BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 Seventh Place East, Suite 350
St. Paul, Minnesota 55101-2147

Beverly Jones Heydinger	Chair
Dr. David C. Boyd	Commissioner
Nancy Lange	Commissioner
J. Dennis O'Brien	Commissioner
Betsy L. Wergin	Commissioner

In the Matter of the Request of Minnesota Power
for a Certificate of Need for the Great Northern Transmission Line

MPUC Docket No. E-015/CN-12-1163

Application For A Certificate Of Need

October 21, 2013

minnesota power
AN ALLETE COMPANY

GREAT NORTHERN
TRANSMISSION LINE

TABLE OF CONTENTS

LIST OF APPENDICES

N	Dorsey – Iron Range 500 kV Project Preliminary Stability Analysis, December 5, 2012
O	Manitoba – United States Transmission Development Wind Injection Study, March 1, 2013
P	MH – US TSR Sensitivity Analysis Draft Reports, January 2013
Q	New Tie Line Loop Flow Impact Study, October 14, 2013 Draft Study Scope
R	MISO Information on Potential Generation Additions and Retirements

TABLE OF FIGURES AND TABLES

TABLE OF STUDIES

Official Study Name - Appendix (if applicable)	Study Owner	Study Objective	Great Northern Transmission Line (Project)	Fargo Area Study Concept	Hybrid Alternative
Manitoba Hydro Wind Synergy Study, September 2013 - Appendix I	MISO	Look at synergy between Manitoba hydropower and MISO wind power	Eastern Option	Western Option	Central Option
Great Northern Transmission Line, Economic Impact on Northern Minnesota, University of Minnesota Duluth, Labovitz School of Business and Economics, July 2013 – Appendix L	Minnesota Power	To evaluate the economic impact of the Great Northern Line on the northern Minnesota economy	Great Northern Transmission Line	n/a	n/a
GNTL Economic Impact Study (will be provided when final draft issued)	Minnesota Power	To evaluate the economic impact of the Project based on its impact on locational marginal prices, adjusted production costs, and losses	Great Northern Transmission Line	n/a	n/a
Northern Area Study, June 2013 – Appendix M	MISO	A regional evaluation of production cost savings potential and reliability issues in MISO's northern footprint	New Manitoba - Duluth 500 kV Tie Line	New Manitoba - Fargo 500 kV Tie Line	New Manitoba - "T" 500 kV Tie Line
MHEB Group TSR System Impact Study	MISO	Analyze system impact of long-term transmission service requests and associated transmission	Option 3[1]	Option 1	n/a

[1] "Option 3" was a new 50 percent series compensated 500 kV line from Dorsey – King; there are significant differences between this option and the Great Northern Transmission Line.

MHEB Group TSR System Impact Study Transmission Options W.1 and W.2	MISO	Analyze system impact of long-term transmission service requests and associated transmission	n/a	Option W.1	n/a
MH – US TSR Sensitivity Analysis Draft Reports, January 2013 – Appendix Q	MISO	Perform sensitivity analysis on alternative transmission options for the MH-US south bound TSRs, including different MH-US transfer levels	Eastern Plan	Western Plan	n/a
Manitoba Hydro Preliminary Group Facility Study Report for MHEM (to be provided when final draft issued)	Manitoba Hydro	To quantify impacts of new reservations on the steady state and dynamic performance of the interconnected Manitoba - United States system	Iron Range Injection	Fargo Injection	n/a
White Paper on Series Capacitor Upgrade Issues, July 2013	Manitoba Hydro	To summarize potential issues with increasing the rating of D602F (M602F) from 2000 Amp to 2500 Amps	n/a	n/a	n/a
Manitoba Hydro Transmission Expansion (MANTEX) Study, August 1, 2012	Xcel, GRE, OTP, MRES	To provide thoroughly studied projects for inclusion in the MISO Wind Synergy Study	n/a	Option B	n/a
Minnesota Route Transmission Option Study, April 3, 2013	Xcel, GRE, OTP, MRES	To evaluate the system performance of MANTEX Option B if the routing is on the Minnesota side of the Minnesota-North Dakota border and the line terminates near Barnesville, MN	n/a	Option B'	n/a
Impact of CapX Facilities on North Dakota Export for the Year 2016 Report, June 2012	CapX2020	To determine the impact of the CapX2020 facilities on the North Dakota Export (NDEX) limit	n/a	n/a	n/a

Dorsey – Iron Range 500 kV Project Preliminary Stability Analysis, December 5, 2012 - Appendix N	Minnesota Power	Preliminary stability analysis on new 500 kV tie line configurations	Dorsey - Iron Range	Dorsey - Bison	n/a
Manitoba – United States Transmission Development Wind Injection Study, March 1, 2013 – Appendix O	Minnesota Power	Identify and evaluate incremental Western Minnesota wind injection capability in conjunction with 1100 MW of new Manitoba to United States transmission service requests and their associated facilities	Iron Range Option	Fargo Option	n/a
Eastern MN 500 kV Transmission Study, August 31, 2012	Xcel, GRE, OTP, MRES	To analyze the performance of an Eastern Minnesota 500 kV option and compare it to MANTEX Option B	Eastern 500 kV Option[2]	Option B	n/a
Dakota Wind Study, August 31, 2012	Xcel, GRE, OTP, MRES	Building on the results of the MANTEX study, to identify additional transmission upgrades needed to transfer wind power from the Dakotas	n/a	Option B	n/a
New Tie Line Loop Flow Impact Study – October 14, 2013 Draft Study Scope included as Appendix P; final report will be provided when available	Minnesota Power	To capture the impact of a new 500 kV Manitoba - United States tie line on the North Dakota - Manitoba loop flow phenomenon	Eastern Plan	Western Plan	n/a

[2] The "Eastern 500 kV Option" was developed without input from Minnesota Power or Manitoba Hydro; there are significant differences between this option and the Great Northern Transmission Line.

**GREAT NORTHERN TRANSMISSION LINE –
COMPLETENESS CHECKLIST
FOR CERTIFICATE OF NEED APPLICATION**

Authority	Title/Required Information	Section of Initial Filing
Minn. Rule 7829.2500	**CERTIFICATE OF NEED FILING**	
Subp. 2	Brief summary of filing sufficient to apprise potentially interested parties of its nature and general content.	Appendix A
Minn. Rule 7849.0120	**CRITERIA**	
A.	Showing that denial would adversely affect adequacy, reliability and efficiency, considering:	Throughout and Sections 2.1, 6 and 8.1
1.	Demand forecast for type of energy supplied by proposed facility is accurate.	Sections 1.4, 2.1 and Appendices H and J
2.	Effects of applicants' conservation program and state and federal conservation programs.	Sections 1.4, 2.1, 7.5.1 and Appendix K
3.	Effects of applicants' promotional practices on energy demand.	Section 2.3
4.	Ability of current facilities and facilities not requiring a Certificate of Need to meet future demand.	Section 7.5
5.	Effect of proposed facility in making efficient use of resources.	Section 2.2
B.	A more reasonable and prudent alternative has not been demonstrated, considering:	Sections 7 and 8.2
1.	Facility is appropriate size, type and timing compared to reasonable alternatives.	Section 7

2.	Cost of facility and of its energy compared to reasonable alternatives.	Sections 4.3 and 7
3.	Effects of the proposed facility upon the natural and socio-economic environment compared to the effects of reasonable alternatives.	Section 5.4 and Appendices G and L
4.	Expected reliability of facility compared to reasonable alternatives.	Section 7
C.	Project will provide benefits to society, considering:	Sections 2, 6.4, 8.3 and Appendix L
1.	Relationship of facility to overall state energy needs.	Sections 2.1, 6.4.1 and 8.3
2.	Effects of facility on natural and socio-economic environment compared to not building facility.	Sections 2.1.3, 5, and 6.4.2
3.	Effects of facility inducing future development.	Sections 2.4, 6.4.3 and 8.3
4.	Socially beneficial uses of the output of the facility, including its uses to protect or enhance environmental quality.	Sections 6.4.3 and 8.3
D.	Project will comply with relevant policies and regulations of other state and federal agencies and local governments.	Sections 3.5, 6.5 and 8.4
Minn. Rule 7829.0200	**APPLICATION PROCEDURES AND TIMING**	
Subp. 2	Title page, table of contents, and list of applicable rules.	Cover page; pp. i through xxvi
Subp. 4	Cover letter.	Cover letter
Minn. Rule 7849.0210	**FILING FEES AND PAYMENT SCHEDULE**	Paid under separate cover

Minn. Rule 7849.0240	**NEED SUMMARY AND ADDITIONAL CONSIDERATIONS**	
Subp. 1	Need summary (major factors that justify need for facility).	Section 2
Subp. 2	Additional considerations:	
A.	Socially beneficial uses of facility output, including uses to protect or enhance environmental quality.	Section 2.2
B.	Promotional activities that may have given rise to demand.	Section 2.3
C.	Effects of the facility in inducing future development.	Section 2.4
Minn. Rule 7849.0260	**PROPOSED LHVTL AND ALTERNATIVES**	
A.	Type and general location of proposed line, including:	Section 4.2
1.	Design voltage.	Section 4.2.1
2.	Number, sizes and types of conductors.	Section 4.2.2
3.	Expected losses under maximum and average loading in line and terminals or substations.	EXEMPT provided alternative data supplied
	ALTERNATIVE – Estimated system losses	Section 4.5
4.	Length of line and portion in Minnesota.	Sections 1.3, 4.1, and 4.2.3
5.	Location of DC terminals or AC substations on map.	Figures 1.5A and 1.5B
6.	List of counties reasonably likely to be affected by construction and operation.	Section 4.1
B.	Availability of alternatives, including:	

1.	New generation of various technologies, sizes, fuel types.	Section 7.3
2.	Upgrade of existing lines or generating facilities.	Section 7.4.1
3.	Transmission with different voltages or conductor arrays.	Section 7.4.2
4.	Transmission lines with different terminals or substations.	Section 7.4.3
5.	Double circuiting of existing transmission lines.	Section 7.4.4
6.	If facility is for DC (AC) transmission, an AC (DC) transmission line.	Section 7.4.5
7.	If facility is for overhead (underground) transmission, an underground (overhead) transmission line.	Section 7.4.6
8.	Any reasonable combination of alternatives (1) – (7).	Sections 7.3 and 7.4
C.	For facility and for each alternative, discuss:	
1.	Total cost in current dollars.	Sections 4.3.1 and 7.4
2.	Service life.	Sections 4.3.2 and 7.4
3.	Estimated average annual availability.	Sections 4.3.3 and 7.4
4.	Estimated annual operating and maintenance costs in current dollars.	Sections 4.3.4 and 7.4
5.	Estimate of its effect on rates system-wide and in Minnesota.	Sections 4.3.5 and 7.4
6.	Efficiency, expressed as expected losses under maximum and average loading in lines and terminals or substations.	EXEMPT provided alternative data supplied
	ALTERNATIVE – Estimated system losses	Section 4.5

7.	Major assumptions made in sub items (1) – (6).	Sections 4.3, 4.5 and 7.4
D.	Scaled map showing the system or load center to be served.	Figure 4.4
E.	Any other relevant information about the proposed facility and each alternative.	Sections 6.3, 7.4 and 7.5
Minn. Rule 7849.0270	**PEAK DEMAND AND ANNUAL CONSUMPTION FORECAST**	
Subp. 1	Pertinent data concerning peak demand and annual electrical consumption.	EXEMPT provided alternative data supplied
	ALTERNATIVE – July 2013 Advanced Forecast Report	Appendix H
Subp. 2	Forecast consumption data by customer class; forecast demand data by peak period, customer class, and month; estimated system annual revenue per kilowatt hour; estimated average system load factor by month.	EXEMPT except as noted below and provided alternative data supplied
	ALTERNATIVE – July 2013 Advanced Forecast Report; including provision of AFR data that includes specific industrial load growth scenarios.	Appendix H
	Subp. 2 (D) – Applicant's system peak demand by month.	Appendices H and J
	Subp. 2 (E) – Alternative explanation of how wholesale electricity costs are spread and general financial effect on Minnesota Power customers.	Section 4.3.5
Subp. 3	Detail of the forecast methodology employed in subp. 2.	Appendices H and J
Subp. 4	Discussion of the database used in current forecasting.	Appendices H and J

Subp. 5	Discussion of each assumption made in forecast preparation and sensitivity to variations in assumptions.	Appendices H and J
Subp. 6	Coordination of forecasts.	Appendices H and J
Minn. Rule 7849.0280	**SYSTEM CAPACITY**	
A.	Discussion of power planning programs applied to applicant's system and power area upon which planning studies are based.	Appendix J
B.	Applicant's seasonal firm purchases and firm sales for each utility involved in each transaction for each forecast year.	EXEMPT
C.	Applicant's seasonal participation purchases and sales for each utility involved in each transaction for each forecast year.	EXEMPT
D.	Load and generation capacity data requested in subitems 1-13 for summer and winter seasons for each forecast year, including anticipated purchases, sales, and capacity retirements and additions except those that depend on a not yet issued certificate of need.	EXEMPT
E.	Load and generation capacity data requested in item D, subitems 1-13 for summer and winter seasons for each forecast year, including purchases, sales and generating capability contingent on the proposed facility.	EXEMPT
F.	Load and generation capacity data requested in item D, subitems 1-13 for summer and winter seasons for each forecast year, including all projected purchases, sales and generating capability.	EXEMPT

G.	List of proposed additions and retirements in net generating capability for each forecast year, including the probable date of application for any addition that is expected to require a certificate of need.	EXEMPT
H.	Graph of monthly adjusted net demand and adjusted net capability as well as the difference between the adjusted net capability and actual, planned, or estimated maintenance outages of generation and transmission facilities for the previous calendar year, the current year, the first full calendar year before the proposed facility is expected to be operational and the first full calendar year of operation of the proposed facility.	Appendix Q
I.	Discussion of the appropriateness of and method of determining system reserve margins, considering the probability of forced outages of generating units, deviation from load forecasts scheduled maintenance outages of generation and transmission facilities, power exchange arrangements as they affect reserve requirements, and transfer capabilities.	CLARIFIED per below by Exemption Order
	CLARIFICATION – Information related to transfer capabilities is relevant and Minnesota Power will provide information about the integrated transmission system, including information from MISO on any planned additions and retirements.	Sections 7.2 and 7.4.3, Appendices I, M and N
Minn. Rule 7849.0290	**CONSERVATION PROGRAMS**	
A.	Name of committee, department, or individual responsible for the applicant's energy conservation and efficiency programs, including load management.	EXEMPT provided alternative data provided

B.	List of the applicant's energy conservation and efficiency goals and objectives.	EXEMPT provided alternative data provided
C.	Description of the specific energy conservation and efficiency programs the applicant has considered, a list of those that have been implemented, and the reasons why the other programs have not been implemented.	EXEMPT provided alternative data provided
D.	Description of the major accomplishments that have been made by the applicant with respect to energy conservation and efficiency.	EXEMPT provided alternative data provided
E.	Description of the applicant's future plans through the forecast years with respect to energy conservation and efficiency.	EXEMPT provided alternative data provided
F.	Quantification of the manner by which these programs affect or help determine the forecast provided in response to part 7849.0270, subp. 2, a list of their total costs by program, and a discussion of their expected effects in reducing the need for new generation and transmission facilities.	EXEMPT provided alternative data provided
	ALTERNATIVE – Minnesota Power will provide a summary of its 2013 Integrated Resource Plan and Conservation Improvement Program filings, along with additional CIP information to be filed in 2013.	Appendices J and K, Sections 6.2, 6.4 and 7.4.1
Minn. Rule 7849.0300	**CONSEQUENCES OF INDEFINITE DELAY AND 1, 2, OR 3 YEAR POSTPONEMENT UNDER THREE LEVELS OF DEMAND**	EXEMPT provided alternative data provided

	ALTERNATIVE – the transfer capability requirements that are necessary to import generation from Manitoba Hydro and what any delay in facilitating additional transfer capabilities would mean to Minnesota and the region; currently proposed and projected retirements of baseload facilities in the Upper Midwest that likely would create a need for other baseload resources to be identified and readily available, and if any delay in the Project would have any consequences for decisions to be made on Minnesota Power's system; and the consequences of any delay or no-facility alternative to the analysis reviewed by the Commission when it approved Minnesota Power's PPA with Manitoba Hydro for 250 MW related to Minnesota Power's own energy needs.	Sections 6.1, 6.2, 6.5, 7.2 and 7.4.3, Appendices I, M and N
Minn. Rule 7849.0310	**ENVIRONMENTAL INFORMATION**	Appendix G and Sections 4, 5.2 - 5.4 and 7
Minn. Rule 7849.0330	**TRANSMISSION FACILITIES ALTERNATIVES**	
A.	For overhead transmission facilities:	
1.	Schematic diagrams that show the dimensions of the support structures and conductor configurations for each type of support structure that may be used.	Section 4.2
2.	Discussion of the strength and distribution of the electric field attributable to the transmission facility, including the contribution of air ions is appropriate.	Section 5.4.1
3.	Discussion of ozone and nitrogen oxide emissions attributable to the transmission facility.	Section 5.4.2

4.	Discussion of radio and television interference attributable to the transmission facility.	Section 5.4.3
5.	Discussion of the characteristics and estimated maximum and typical levels of audible noise attributable to the transmission facilities.	Section 5.4.4
B.	For underground transmission facilities.	Not applicable
C.	Estimated width of the right-of-way required for the transmission facility.	Section 5.1
D.	Description of the construction practices for the transmission facility.	Section 5.2
E.	Description of operation and maintenance practices for the transmission facility.	Section 5.3
F.	Estimated work force required for construction, operation, and maintenance of the transmission facility.	Section 5.2.3, and Appendix L
G.	Narrative description of the major features of the region between the endpoints of the transmission facility, encompassing the likely area for routes between the endpoints and emphasizing the area within three miles of the endpoints. The following information shall be described where applicable:	Appendix G
1.	Hydrologic features including lakes, rivers, streams, and wetlands.	Appendix G
2.	Natural vegetation and associated wildlife.	Appendix G
3.	Physiographic regions.	Appendix G
4.	Land-use types, including human settlement, recreation, agricultural production forestry production, and mineral extraction.	Appendix G

Minn. Rule 7849.0340	NO FACILITY ALTERNATIVE	
A.	Description of the expected operation of existing and committed generating and transmission facilities.	EXEMPT provided alternative data provided
B.	Description of changes in resource requirements and wastes produced by facilities discussed in response to item A.	EXEMPT provided alternative data provided
C.	Description of equipment and measures that may be used to reduce the environmental impact of the alternative of no facility.	EXEMPT provided alternative data provided
	ALTERNATIVE – the transfer capability requirements that are necessary to import generation from Manitoba Hydro and what any delay in facilitating additional transfer capabilities would mean to Minnesota and the region; currently proposed and projected retirements of baseload facilities in the Upper Midwest that likely would create a need for other baseload resources to be identified and readily available, and if any delay in the Project would have any consequences for decisions to be made on Minnesota Power's system; and the consequences of any delay or no-facility alternative to the analysis reviewed by the Commission when it approved Minnesota Power's PPA with Manitoba Hydro for 250 MW related to Minnesota Power's own energy needs.	Sections 6.1, 6.2, 6.5, 7.2 and 7.4.3, Appendices I, M and N

ADDITIONAL REQUIREMENTS FROM EXEMPTION ORDER (Appendix B)		
	data describing the existing generation, and any planned additions and retirements, in the integrated regional transmission system. This information would be helpful to assess the ability of the proposed lines to accommodate generation needs;	Section 7.4 and Appendix N
	information and explanation of the effects, costs, benefits, and drawbacks of the proposed project on other utilities in the state and region	Sections 4.3.5, 7.2 and 7.4, Appendices I, M and N
	the same information concurrently in these proceeding as what Minnesota Power is required to file in the PPA docket.	Sections 2.2 and 7.3

1. EXECUTIVE SUMMARY

1.1. Introduction

Minnesota Power (also "Company") hereby applies to the Minnesota Public Utilities Commission ("Commission") for a Certificate of Need to construct the Great Northern Transmission Line ("Project").

The Project is guided by the Company's 2013 Integrated Resource Plan ("2013 Plan") and enables Minnesota Power to implement the next chapter in the Company's Energy***Forward*** resource strategy.[3] The Project, a central element of the 2013 Plan approved by the Commission on September 25, 2013,[4] brings a host of benefits while enabling Minnesota Power to meet its customers' need for power economically and sustainably. Those benefits include, but are not limited to, enabling Minnesota Power to diversify its baseload generation portfolio and reduce the overall emissions associated with its electric supply portfolio. The Project also improves Minnesota's ability to import renewable energy from the west, while increasing transmission system deliverability and reliability for a broad region of the Upper Midwest and supporting recent and planned industrial growth on the Iron Range in northern Minnesota. In addition, the Project provides substantial economic benefits in the form of property tax revenue, construction and maintenance jobs and increased business along the final route.

1.2. Procedural Background

In anticipation of this Certificate of Need filing, on October 29, 2012 the Company filed a notice plan under Minn. R. 7849.2550 and on November 20, 2012, it filed a request for an exemption from certain data requirements under Minn. R. 7849.0200, subp. 6. The Department of Commerce ("Department") evaluated the proposed notice plan and requested that the Company provide further detail on how its plan meets the requirement to notify tribal governments and the governments of towns, statutory cities, home rule charter cities, and counties whose jurisdictions are reasonably likely to be affected by the proposed line. On December 10, 2012, Minnesota Power provided a more detailed description of the government and tribal officials and administrators who will be notified of the Project. The Department therefore subsequently recommended that the

---

[3] Minnesota Power announced its Energy***Forward*** resource strategy in late January 2013. Energy***Forward*** builds upon renewable investments already completed. It further diversifies Minnesota Power's generation mix, balancing coal, natural gas and renewable energy resources and builds upon significant emissions reductions at existing power plants. At the same time, Energy***Forward*** preserves the reliable and affordable power Minnesota Power's customers have come to expect.

[4] *See* MPUC Docket No. E-015/RP-13-53. The Commission orally approved the 2013 Plan at its September 25, 2013 Agenda Meeting. At the time of this application, the Commission has yet to issue its Order memorializing that vote.

Commission approve the plan, concluding that the notice plan meets the requirements of Minn. R. 7829.2550 and the Commission concurred, issuing its Order Approving the Notice Plan on February 28, 2013. Minnesota Power implemented the approved Notice Plan in August 2013 and will submit the required compliance filings. The Commission Order Approving the Notice Plan is included herein as Appendix B.

At the time Minnesota Power filed its proposed notice plan and its exemption request, the Company anticipated filing a Certificate of Need application for two transmission lines and associated facilities – the Project and a separate 345 kilovolt ("kV") transmission project between the terminus substation of the Project and the Arrowhead Substation near Hermantown, Minnesota. At this time there are not sufficient transmission service requests to support this second 345 kV phase. Thus, Minnesota Power has determined that it will not pursue construction of the 345 kV project at this time. Should that separate project move forward in the future, a new Certificate of Need application will be filed.

Also by Order on February 28, 2013, the Commission granted Minnesota Power's request to be exempted from certain data requirements and to be exempted from certain additional data requirements provided it supply alternative data with this Application. The Company provides all such alternative data, as set forth in the Certificate of Need Completeness Checklist provided with this Application.

1.3. Project Description

Minnesota Power, in partnership with Manitoba Hydro, proposes to construct a 500 kV transmission line from the International border that would terminate at the Blackberry Substation in Itasca County (spanning an estimated 235 to 270 miles). Construction of the line is anticipated to begin in June, 2016 and take approximately 48 months to complete, with a projected in-service date of June 1, 2020. While Minnesota Power is evaluating the possibility of building additional lines in Minnesota beyond the 500 kV transmission line at some time in the future, the Project is limited to the 500 kV transmission line.

The primary objective of the Project will be to provide increased access to Manitoba hydropower. Additionally, the Project facilitates an innovative wind storage provision in the PPA that leverages the flexible and responsive nature of hydropower to optimize the value of Minnesota Power's significant wind energy investments and allows Minnesota Power to take another positive step in its Energy***Forward*** resource strategy.

The Project will provide delivery and access to power generated by Manitoba Hydro's hydroelectric stations in Manitoba, Canada. The Project is required to facilitate delivery of 383 megawatts ("MW") of hydropower and wind storage energy products to serve Minnesota Power customers – including a 250 MW power purchase agreement ("PPA") and Energy Exchange Agreement ("EEA") (collectively the "250 MW Agreements"), approved by the Commission in 2012, along with a new agreement for an additional 133 MW Energy Sale Agreement and Energy Exchange Agreement (collectively, the "133 MW Renewable Optimization Agreements"). Combining the two agreements, Minnesota Power has procured a combined total of over 1.5 million megawatt hours ("MWh") annually, with the ability annually to store 1 million MWh of wind power in Manitoba Hydro's system.

First, Minnesota Power needs this line to deliver at least 250 MW of energy and capacity and to optimize Minnesota Power's wind resources under the 250 MW Agreements approved by the Commission on February 1, 2012 in MPUC Docket No. E-015/M-11-938 ("938 Docket").[5] The innovative wind storage provision of the 250 MW Agreements leverages the flexible and responsive nature of hydropower to enhance the value of Minnesota Power's significant wind energy investments.

Second, Minnesota Power and Manitoba Hydro recently finalized a Term Sheet for the 133 MW Renewable Optimization Agreements includes an additional 750,000 MWh of renewable energy storage, by June 1, 2020, included as Appendix D (including both Public and Nonpublic versions). Minnesota Power will submit the new 133 MW Renewable Optimization Agreements to the Commission for approval upon the parties' finalization of terms and execution.

Several other items also drive the need for a new transmission line to be built from Manitoba, Canada to Minnesota Power's Blackberry Substation, including the increasing demand for access to competitively priced, emission-free, renewable energy for Minnesota Power and the region, serving growing industrial load on the Iron Range, strengthening regional transmission reliability and taking advantage of the synergies of wind and hydroelectric power.

The Project is further described in Section 4, below.

1.4. Project Need

As discussed in detail below, the Project provides critical new transmission resources for northern Minnesota and the region by providing an additional high voltage tie line between Manitoba and the United States. Not only are the current transmission resources unable to facilitate significant new energy exchanges, the existing 500 kV tie-line between Manitoba and the United States represents the single largest contingency in the region. As such, new transmission not only enables additional energy exchanges, but strengthens the regional transmission grid as well.

[5] The Commission Order and Department Comments in the 938 Docket, approving the 250 MW Agreements and recognizing the need for new transmission facilities to deliver this energy, are attached as Appendix C.

For Minnesota Power's customers, the Project represents the Minnesota portion of major new transmission facilities necessary to deliver the power called for under the Commission-approved 250 MW Agreements discussed above. The 938 Docket completed a regulatory process of identifying Minnesota Power's resource needs and selecting the best means of meeting those needs. That process began with Minnesota Power's 2010 Integrated Resource Plan ("IRP" or "Plan") docket, MPUC Docket No. E-015/RP-09-1088 ("1088 Docket"), where Minnesota Power included in its long-term action plan pursuing a "250 MW expansion of Manitoba Hydro generation and associated transmission in [the] 2020 time frame."[6] Subsequently, the Commission and Department affirmed that Minnesota Power had significant projected capacity and energy deficits over the period 2020-2035, and therefore the company "would need a significant additional amount of peaking capacity and energy to meet its future capacity and energy needs."[7]

In approving the 250 MW Agreements as providing a needed and appropriate resource, the Department and Commission each recognized that "both [Manitoba Hydro, "MH" in Commission and Department documents] and [Minnesota Power, "MP" in Commission and Department documents] <u>must construct their own new transmission facilities (in Canada and the USA respectively) to allow MH to sell the contracted power to MP</u>."[8] Given this recognized need for new transmission, the Commission's Order required Minnesota Power to "file a report in this docket on various significant milestones achieved regarding the new hydraulic generating facilities and the new major transmission facilities."[9]

Manitoba Hydro is simultaneously developing the Canadian portion of these major new transmission facilities and on August 16, 2013, submitted its Needs For and Alternatives To ("NFAT") filing with the Manitoba Public Utilities Board. In its NFAT submission, Manitoba Hydro details its Preferred Development Plan, including commencing construction of the 695 MW Keeyask Generating Station in June 2014 for a 2019 in-service date along with the construction of the Canadian transmission component that will meet the Project at the United States – Canada border. The Executive Summary of the NFAT filing is attached as Appendix E.[10] In addition, Manitoba Hydro will file with the National Energy Board ("NEB") for approval of the Canadian portion of this new transmission project, given that the line will cross the Canadian-United States border.

---

[6] MPUC Docket No. E-015/RP-09-1088, Order Accepting Resource Plan and Requiring Compliance Filings, May 6, 2011, p. 4.

[7] Appendix C, Department Comments, p. 4.

[8] Appendix C, Department Comments, p. 13 (emphasis added).

[9] Appendix C, p. 1.

[10] The entire NFAT filing is available for viewing or downloading at: www.hydro.mb.ca/projects/development_plan/nfat_business_case.shtml.

Manitoba Hydro will also be required to seek approval for the routing of the Canadian portion of this new transmission interconnection.

This Application further addresses the need for the Project in Sections 2 and 6, below.

1.5. Project Study Area and Potential Routes

Routing for the Project will be considered in both the Presidential Permit required for the Project and in the Route Permit process, which will come before the Commission in a separate docket.[11] At this time, three potential international border crossing areas remain under consideration, near US Highway 59 in Kittson County, County State Aid Highway 24 along the Kittson/Roseau County border, and Minnesota Trunk Highway 89 in Roseau County. The route corridors from those crossing areas to the Blackberry Substation in Itasca County reflect the consideration of a number of factors, including infrastructure sharing opportunities, large water bodies, Scientific and Natural Areas, State Parks, and large areas of open wooded wetland and cities.

Figure 1.5A on the next page sets forth the study area, route corridors, and route alternatives originally considered.

Following further analysis and multiple stakeholder meetings, Figure 1.5B sets forth the route alternatives currently under consideration.

---

[11] On July 2, 2013, Minnesota Power sent the United States Department of Energy its "Letter of Intent to Submit Presidential Permit Application" for the Project and includes a copy of that letter as Appendix F.

FIGURE 1.5A - Study Area and Potential Route Corridors

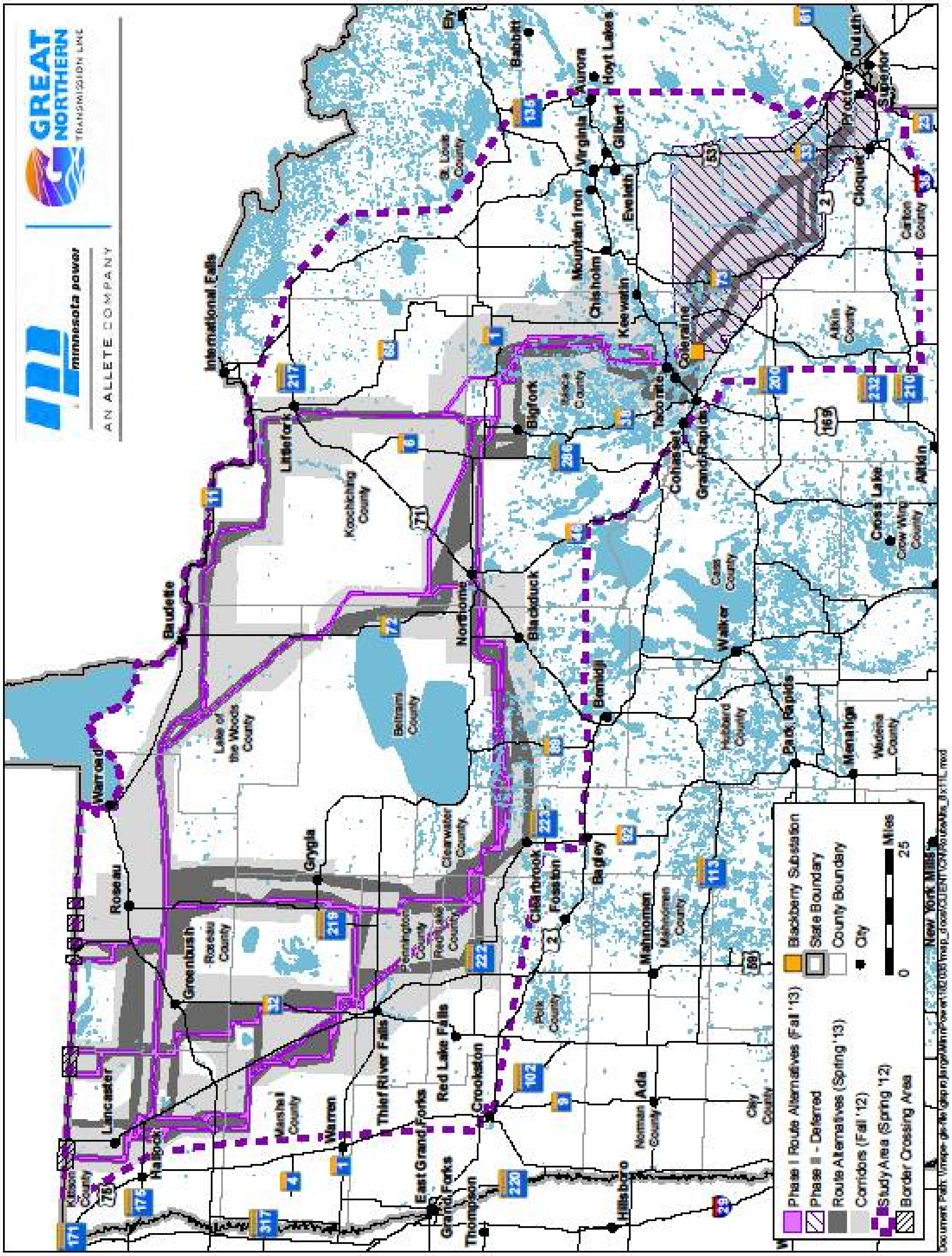
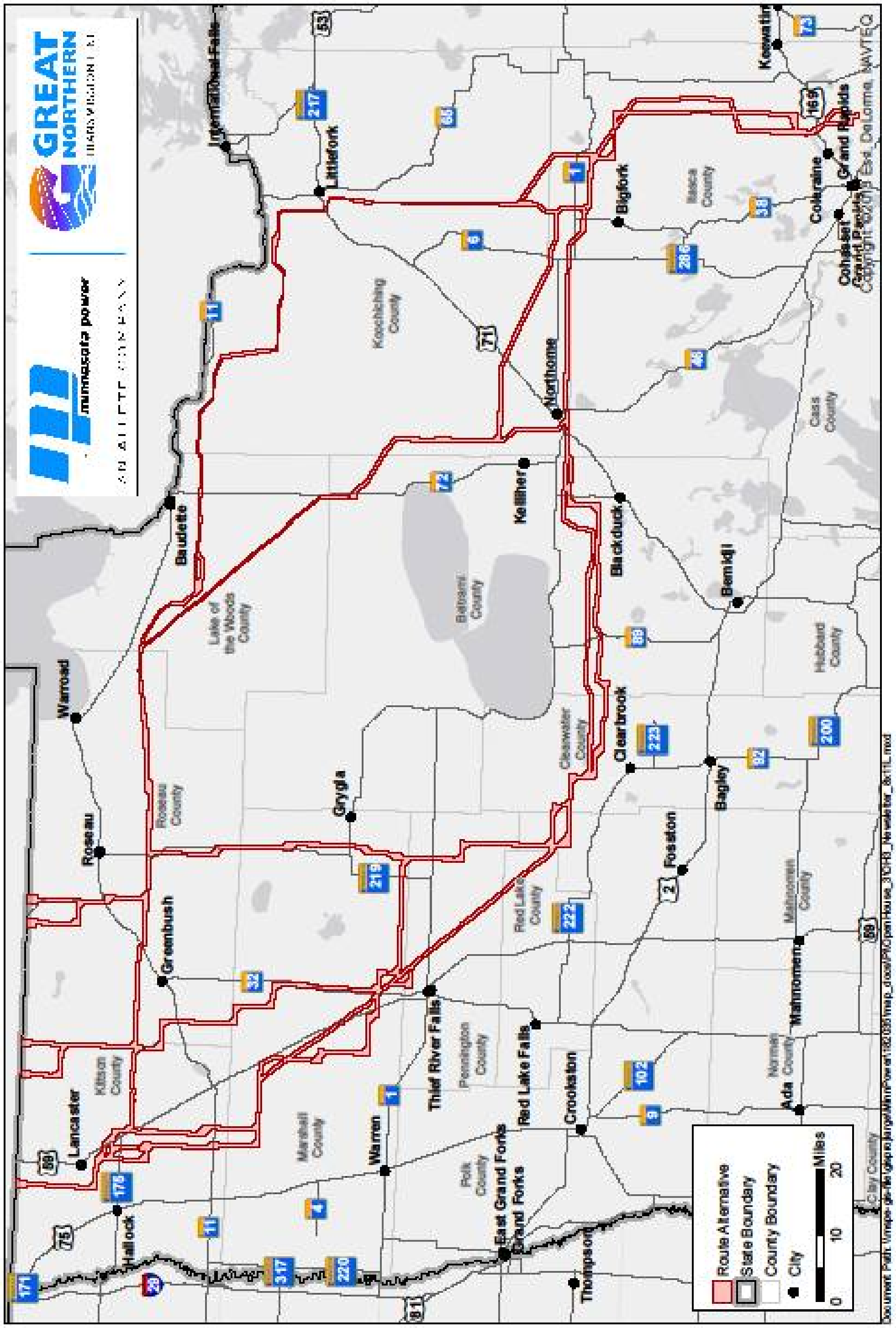


FIGURE 1.5B - Route Alternatives Currently Under Consideration



1.6. Alternatives to the Project

Minnesota Power has analyzed various alternatives to the Project, as discussed in Section 7, below. Alternatives considered included: (1) a "no-build" alternative, exploring whether conservation, demand side management and existing resources could meet the needs identified; (2) other generation alternatives, including distributed generation; and (3) various transmission system alternatives, including various size lines, various terminal points, and upgrades of existing facilities. No alternative considered more reasonably or prudently meets the need for increased transmission capabilities to serve Minnesota Power, its customers and the region than the Project. Moreover, denial of a Certificate of Need for the Project would severely impact Minnesota Power and its customers, as the Company would be unable to effectuate the Commission-approved 250 MW Agreements and the 133 MW Renewable Optimization Agreements with Manitoba Hydro and would be unable to deliver these needed resources to its customers, denying them the environmental, economic and reliability benefits the Agreements and Project together will provide.

1.7. Environmental Impacts

Minnesota Power has identified preliminary route alternatives for the Project, as shown in Figure 1.5B, that allow optimum performance of the proposed transmission line, while minimizing the impacts to social, economic and environmental resources. As permitting processes move forward, Minnesota Power will continue to receive public, landowner, agency and other stakeholder input, as well as field surveys and additional analyses, to determine the final route alternatives that will be presented to the Commission. As part of this process, sensitive areas will be avoided to the extent practicable and, in any areas where avoidance is not practicable, reasonable impact minimization and mitigation measures will be developed and implemented. More detailed discussion of environmental impacts associated with the Project is included in Section 5.4 and in the Draft Environmental Report, attached as Appendix G.

1.8. Public and Agency Involvement

Minnesota Power has already engaged hundreds of landowners, the public and federal, state and local agency stakeholders through a variety of means, as discussed further in Section 3.3, below, and will continue to encourage broad public and agency participation.

The public can review this application and submit comments to the Commission on the state's eDockets page. A copy of this Application and additional relevant materials can also be viewed on the Project's web page at http://greatnortherntransmissionline.com. Minnesota Power will also be filing a Route Permit Application for the Project. Once filed, the Route Permit Application will also be available on the state's eDockets site and on the Project web site.

In August 2012, after coordination with relevant federal and state agencies, Minnesota Power conducted 11 stakeholder workshops to discuss the project study area, including constraints to development within the study area. A total of 54 persons attended those workshops and Minnesota Power also received 37 community surveys and 142 comments regarding the maps of the proposed study area.

In October and November 2012, Minnesota Power presented its initial corridors to the public at a series of 11 agency and public meetings held within the project study area. Nearly 600 persons attended those meetings and an additional 80 visitors accessed an "online open house" held on the Project web site. The Company received over 150 mapping comments and 16 comment forms from these meetings.

Since that time, Minnesota Power has published and distributed a newsletter on the Project and in April 2013 held a series of 14 public open house meetings to both provide information and to receive public feedback and input to be utilized as the routing process moves forward. The purpose of these meetings was to further refine the potential routing alternatives through direct public input and involvement. Nearly 750 people attended this series, with 269 additional visitors accessing the online open house. Minnesota Power received nearly 250 mapping comments, over 50 comment forms and 38 online meeting comments from this series of meetings.

Minnesota Power held another series of public open house meetings, as well as an online open house meeting in September 2013, to gather input from local stakeholders and the public on the narrowed proposed route alternatives for the Project. A total of 683 persons attended these meetings, with over 100 attending on-line, and the meetings generated approximately 100 comment forms and 250 mapping comments.

Along with these public meetings, Minnesota Power has been actively engaged in meetings with several state and federal agencies to discuss various aspects of the routing and environmental review processes before those agencies and to begin discussing permitting and mitigation strategies. Additionally, an "all agencies" meeting was held in December 2012 to provide a project introduction and to begin inter-agency discussions on the Project. Eleven agencies attended that meeting and, in total, Minnesota Power has held more than 20 different meetings with 16 state and federal agencies through September 2013.

1.9. Conclusion

As demonstrated below and in the attached Appendices, the Project meets all criteria set forth in Minnesota statutes and rules for the granting of a Certificate of Need. First, the probable result of denying this Application would be an adverse effect on the future adequacy and reliability of the transmission system and on the ability of Minnesota Power to meet the electric supply needs of its customers with this renewable resource. Second, no more reasonable and prudent alternative exists to the Project. Third, the

Project will provide benefits to society compatible with protecting the environment. Fourth, the Project will comply with all applicable standards and regulations.

In addition, the route corridors identified, which will be further developed and finalized in the route permit proceeding, provide opportunities to develop viable routes that will utilize existing corridors to the extent reasonable and practical. No system performance, reliability, economic or environmental issues have been identified that would preclude construction of the Project. Finally, the Project is a central element of Minnesota Power's Energy***Forward*** resource strategy, delivering an affordable, reliable and environmentally sustainable and diverse mix of energy resources for its customers.

For the reasons discussed above and in the remainder of this Application and Appendices, Minnesota Power respectfully requests that the Commission find this Application complete and, upon completion of its review, grant a Certificate of Need for the Project. All correspondence relating to this Application should be directed to:

Michael Donahue Transmission Project Development Manager Minnesota Power 30 West Superior Street Duluth, MN 55802 Phone: (218) 355-2617 Email: mdonahue@mnpower.com	David Moeller Senior Attorney Minnesota Power 30 West Superior Street Duluth, MN 55802 Phone: (218) 723-3963 Email: dmoeller@allete.com

2. NEED SUMMARY

2.1. Major Factors Justifying Need

2.1.1. Minnesota Power Need

The new transmission line is needed to support and allow for the additional capacity and energy provided by its 250 MW Agreements with Manitoba Hydro in the 938 Docket. In that docket, the Commission recognized that "both MH and MP must construct their own new transmission facilities (in Canada and the USA respectively) to allow MH to sell the contracted power to MP."[12] Moreover, the Commission specifically requested Minnesota Power to update the Commission on the progress on the milestones achieved regarding the "new major transmission facilities" necessary to deliver the capacity and power contracted for under the approved 250 MW Agreements.[13] The Project provides these necessary new major transmission facilities.

For Minnesota Power, the Project will deliver power that meets its anticipated increases in annual energy demand while increasing service reliability and providing a necessary new connection to a clean, renewable energy resource. The Company's anticipated increases in energy demand are demonstrated in its most recent Advanced Forecast Report ("AFR"), filed pursuant to Minnesota Rules 7610 and attached as Appendix H.

Further, Minnesota Power has historically generated the majority of its electricity from coal-fired units located in northern Minnesota and west-central North Dakota. The Company's 2010 Plan introduced a diversification strategy that was furthered with its 2013 Plan. These two most recent IRPs included the Company's growing portfolio of North Dakota wind resources and the Manitoba Hydro – Minnesota Power 250 MW Agreements and the Project, as part of the Company's least cost system-wide supply plan. Development of the Project, and the resulting incorporation of substantial hydropower resources into its long-term power supply, will diversify Minnesota Power's energy portfolio. This will allow Minnesota Power to decrease its reliance on coal-based generation and thereby enable a corresponding decrease in air emissions, while delivering more renewable energy and adding reliable, dispatchable and renewable capacity onto its system. As such, the Project positions Minnesota Power to better anticipate and prepare for any future regulations and policies that restrict carbon emissions or penalize generators of those emissions.

The Project allows Minnesota Power and Manitoba Hydro to take advantage of a unique renewable resource optimization opportunity. As part of the Commission approved 250 MW Agreements and the 133 MW Renewable Optimization Agreements, Minnesota Power will schedule energy from its wind-generating facilities to Manitoba Hydro when

---

[12] Appendix C, Department Comments, p. 13.
[13] Appendix C, p. 1, Ordering Paragraph 2.

wind production is high. When utilizing that wind power, Manitoba Hydro will be able to reduce the flow of water through their hydropower plants, effectively storing energy by increasing the water stored behind those plants. The water stored during this process can be used later to generate electricity to be scheduled to Minnesota when wind energy production is low. These arrangements optimize the use of both wind-generated energy and hydropower, benefitting Minnesota Power's customers.

Finally, while the Project would enable this optimized wind-water "synergy" on a regional basis, the Project facilitates high simultaneous production from both resource types. This efficiency of design provides Minnesota Power and the region with the desired wind-water synergy without restricting the long-term operation of the system when high simultaneous production from wind and hydropower resources is desirable.

2.1.2. State and Regional Need

In addition to meeting the needs of Minnesota Power and its customers, as set forth under Minn. Stat. § 216B.243, subd. 9, the Project meets state and regional needs in multiple ways, including by facilitating the wind-water synergy discussed above. Manitoba Hydro has a long history of energy trading relationships with utilities in the United States and has potential future United States customers that have requested transmission service for delivery of energy and capacity from Manitoba. The High Voltage Transmission Line ("HVTL") developed in the Project would have enough capacity to deliver the 383 MW which are contracted in the 250 MW Agreements and the 133 MW Renewable Optimization Agreements, as well as additional hydropower to other utilities in the United States, thereby meeting future state and regional energy needs. In fact, while large hydropower transfers like this do not satisfy the current renewable energy mandates in Minnesota, such a hydropower transfer could support compliance with renewable energy requirements for utilities in Wisconsin and other states.[14]

Manitoba Hydro is currently engaged in a significant development plan that will provide key benefits to Minnesota Power and other Minnesota and regional utilities and their customers. As part of this development plan, Manitoba Hydro is pursuing: (1) construction of the 695-megawatt Keeyask Generating Station on the Nelson River; (2) construction of the 1,485-megawatt Conawapa Generating Station on the Nelson River; (3) construction of AC transmission facilities in Manitoba, associated with Keeyask and Conawapa; and (4) the Manitoba transmission facilities that will meet the Project at the United States – Canada border, providing additional capacity for new export sales from Manitoba (including those sales to Minnesota Power already approved by the Commission in the 938 Docket), allowing for additional imports into Manitoba from United States utilities as needed, while also enhancing regional reliability.

[14] *See, e.g.,* Wis. Stat. § 196.378, as amended by 2011 Wis. Act 34.

The Project, in conjunction with construction of the connecting facilities in Manitoba, will allow additional energy exchanges between Manitoba and the United States, including additional importation of hydropower to the United States from the planned new hydroelectric facilities not supported by the current regional transmission system. Not only will the Project facilitate these additional energy exchanges, it will also facilitate significant addition of new wind generation, benefitting not just Minnesota Power and its customers, but benefitting other utilities and their customers as they strive to meet aggressive renewable energy standards. In total, the Project will support approximately 750 MW of transfer capability from the United States to Canada that will also facilitate the wind/hydro synergy benefits discussed above.

The Midcontinent Independent System Operator ("MISO") recently conducted its first comprehensive study that looks at the synergy between Manitoba Hydro's hydroelectric power and wind power. The report for this Manitoba Hydro Wind Synergy Study is attached as Appendix I. The Study, discussed further in Section 7.2.2, below, assessed how Manitoba hydroelectric power can work with MISO wind to provide benefits to electric customers within MISO. The study found that a new 500 kV interconnection with Manitoba will provide "significant benefits" to the entire MISO footprint. These benefits over 20 years were valued at approximately $1.6 billion in 2012 dollars and include substantial reductions in wind curtailment in the northern MISO region.

Further, the Project also provides a highly valuable new connection to energy resources in Manitoba. Currently, the regional transmission system includes only a single tie line between Manitoba and the United States that is comparable in size to the Project. An unplanned outage of this existing 500 kV tie line is the single largest contingency in the MISO footprint. Development of a second 500 kV tie line from Manitoba to the Iron Range will reduce loading on the existing 500 kV tie line and improve the performance of the transmission system during this contingency.

In addition, the Project will strengthen the transmission system in an area poised for significant economic growth, with attendant electric load growth. The bulk of this load growth is associated with planned mining and industrial expansion on the Iron Range. Development of a second 500 kV interconnection on the Iron Range will provide another strong source of reliable power to one of the most demanding, rapidly expanding load pockets in the region.

2.1.3. Impact of Denial

Denial of a Certificate of Need for the Project would adversely impact Minnesota Power, its customers, the state and the region. For Minnesota Power, the immediate and direct impact of denial would be the inability to take delivery of power from Manitoba Hydro under the Commission-approved 250 MW Agreements and the 133 MW Renewable Optimization Agreements. Denial of a Certificate of Need for the Project, and the resulting inability for Minnesota Power to take delivery of the contracted hydropower, would leave Minnesota Power with significant unmet needs. Loss of the contract for and ability to access hydropower would come with an economic cost, as well as a cost in diversification of generation resources and a loss of the synergies possible through the coordination of wind and hydropower contemplated by Minnesota Power and Manitoba Hydro.

Additionally, denial of a Certificate of Need would mean the loss of the regional benefits that can be brought about by the Project, including the additional ability to take advantage of the wind-hydro synergies, the ability to meet regional needs with emission-free hydropower, building a more reliable system by reinforcing the connections between Minnesota and Manitoba, thereby addressing the single largest contingency in MISO's northern region, and increasing the transfer capability between Manitoba and the United States, while simultaneously reducing wind curtailments.

2.2. Socially Beneficial Uses of Output of Facility, Including Uses to Protect or Enhance Environmental Quality

2.2.1. Economic Development

By facilitating the Commission-approved 250 MW Agreements, as well as the additional 133 MW Renewable Optimization Agreements, the Project enables Minnesota Power to meet its customers' need for power economically and reasonably. Those benefits include, but are not limited to, enabling Minnesota Power to not only meet a growing industrial need, due to new industrial facilities anticipated in northern Minnesota, but to simultaneously diversify the Company's generation portfolio and reduce the overall emissions associated with its electric supply portfolio. In this manner, the Project reduces Minnesota Power's system exposure to potential future emission reduction requirements and supporting future economic development in the Company's service territory. In addition, the Project provides economic benefits in the form of property tax revenue, construction and maintenance jobs and increased business for hotels, restaurants, and other services along the final route. Minnesota Power estimates that construction of the Project will require over a 200 member work force.

2.2.2. Wind Integration and Portfolio Diversification

The Project supports the economic integration of significant wind resources into the regional transmission system, as demonstrated by MISO's Manitoba Wind Synergy Study. Additionally, by facilitating the existing 250 MW Agreements, as well as the additional 133 MW Renewable Optimization Agreements, the Project makes possible a unique "wind storage" feature of the agreements between Minnesota Power and Manitoba Hydro. Minnesota Power will be able to store wind energy generated in North Dakota in Manitoba Hydro's hydroelectric system. Through a provision in the agreements, Minnesota Power will be able to schedule electric energy to Manitoba Hydro when wind production is high and Minnesota Power electric loads are low, thereby maximizing the value of its wind resources. When using that wind power, Manitoba Hydro would be able to temporarily reduce their hydropower generation by decreasing the flow of water through their hydropower plants. The water stored during that process would be used later to generate electricity to schedule to Minnesota when wind energy production is low. This arrangement optimizes the use of both wind-generated energy and hydropower.

In addition, as discussed above, the Project enables Minnesota Power to diversify its overall electric supply portfolio and lessen its dependence on coal-fired electricity.

2.2.3. Increased Reliability

As noted above, the Project provides a highly valuable second high voltage connection to energy resources in Manitoba. The regional transmission system includes only a single existing tie line between Manitoba and the United States comparable in size to the Project. An unplanned outage of this lone existing 500 kV tie line is the single largest contingency in the region served by MISO. In addition, as discussed in greater detail in Section 7.4, below, the Project brings further reliability and other transmission system benefits to the region, both compared to the existing system and compared to transmission alternatives.

2.3. Promotional Activities Have Not Given Rise to Demand for Facility

Minnesota Power has engaged in no direct promotional activities to encourage the use of more power. In fact, Minnesota Power engages in significant demand-side management and conservation programs, as discussed in Section 7.5.1, below and Appendix K. Therefore, the Project does not respond to any growth in demand due to promotional activities. Rather, the Project responds to Minnesota Power's needs to serve a growing industrial base due to economic growth on the Iron Range, and to fulfill the Company's Energy***Forward*** strategy of lessening dependence on coal-fired facilities, diversifying its supply portfolio and successfully integrating significant additions of wind and other renewable energy resources.

2.4. Future Development

The Project increases overall system transfer capability, as discussed below. In addition, the Project further enables future development in the region by improving the well-documented North Dakota-Manitoba loop flow issue and supporting integration of increased wind generation resources. Finally, by enabling the diversification of Minnesota Power's electric supply portfolio and lowering overall emissions associated with that portfolio, the Project reduces Minnesota Power's customers' exposure to the rate impacts of increased environmental regulations.

3. GENERAL INFORMATION

3.1. Project Ownership

Minnesota Power, an operating division of ALLETE, Inc., will have majority ownership (51%) of the Project. Minnesota Power is a public utility in the State of Minnesota under Minn. Stat. § 216B.02, with its principal place of business at 30 West Superior Street, Duluth, Minnesota 55802. The balance of the Project (49%) will be owned by a subsidiary of Manitoba Hydro. As discussed in the Term Sheet, Minnesota Power and Manitoba Hydro and its subsidiary are still evaluating the ownership structure that fully addresses federal and state regulatory, MISO, legal and tax issues. Minnesota Power will provide the Commission final ownership terms upon completion, as the Commission has required in previous transmission dockets.[15] Minnesota Power will also provide the Commission updates regarding all applicable MISO facilities construction and interconnection agreements.

While Minnesota Power will own 51% of the Project, Minnesota Power's customers will be financially responsible for only 33.3% of the Project's revenue requirements. Minnesota Power will receive an amount equal to the balance of the revenue requirements associated with its ownership percentage (17.7%) from Manitoba Hydro by way of a scheduling fee arrangement included in the proposed 133 MW Renewable Optimization Agreements. Given this arrangement, while the Project will have a transfer capability of approximately 750 MW, Minnesota Power and its customers will be responsible for the revenue requirements associated with 250 MW of that total capability. The rate impacts of this are discussed in Section 4.3.5, below.

Minnesota Power will serve as the construction manager for all assets within the United States and will also operate and maintain all Project assets located within the United States. Minnesota Power, through an Operation and Maintenance agreement will invoice the minority owner monthly for its 49% pro rata share of Operation and Maintenance expenses associated with the Project. Once in-service, functional control of the entire Project will be turned over to MISO.

3.2. Project Participants

The Project represents the United States segment of an overall project to increase the transmission capability between Manitoba and Minnesota and the Upper Midwest. The

---

[15] *See, e.g., In the Matter of the Application Of Great River Energy, Northern States Power Company (d/b/a Xcel Energy) and Others for Certificates of Need for Three 345 kV Transmission Lines with Associated System Connections*; MPUC Docket No. ET-2, E-002, et al./CN-06-1115; Order Granting Certificates of Need, May 22, 2009, Order Point 4, requiring Applicants to "make a compliance filing disclosing each project's transmission capacity, owners and ownership structure."

high voltage transmission facilities on the Canadian side of the border will be owned and operated by Manitoba Hydro, a Provincial Crown Corporation with whom Minnesota Power has signed the Commission-approved 250 MW Agreements and the 133 MW Renewable Optimization Agreements. As the Commission has already found, the Project is needed to facilitate the 250 MW Agreements. The Project will also facilitate the 133 Renewable Optimization Agreements, once the agreements are finalized and approved.

3.3. Public Participation and Stakeholder Involvement in the Process

Minnesota Power has implemented a proactive outreach program to key stakeholders and the public since mid-2012 and plans to carry this approach forward, through the routing phase of the Project. State and federal permitting processes will provide further public involvement opportunities going forward.

Beginning in August 2012, Minnesota Power hosted voluntary public outreach meetings to initiate communication and to identify issues or concerns, gather information, and introduce the Project to these stakeholders early in its development. It is Minnesota Power's experience that bringing the public and stakeholders into the process at an early stage identifies constraints and opportunities, which can then be addressed through avoidance or Project design. Participants in these voluntary meetings have included federal and state agency representatives, county commissioners and planners, city officials, non-governmental organization members, tribal representatives and landowners.

Eleven stakeholder meetings were held in August 2012 followed by 11 public open-house meetings hosted during October-November 2012. A second round of 14 public open-house meetings was held in April 2013, and a third round of 13 public open-house meetings was held in September 2013. Minnesota Power promoted each of the rounds of open house meetings via over 40,000 invitations mailed to landowners, over 2,000 letters mailed to stakeholders, press releases distributed and paid advertisements in over 30 media publications throughout the study area.

In addition to the meetings in the communities at the identified sites, the open-house meetings were available on-line at http://greatnortherntransmissionline.com/.

Table 3.3 on the following page gives a summary of the Stakeholder and Public meetings held through September 2013.

Table 3.3. Summary of Stakeholder and Public Involvement through September 2013

Criteria	Stakeholder Meetings (August 2012)	Public Meetings (Oct./Nov. 2012)	Public Meetings (April 2013)	Public Meetings (September 2013)
Number of Locations	11	11	14	13
Number of Attendees	54 people in attendance	583 people in attendance 80 online meeting unique visitors	747 people in attendance 269 online meeting unique visitors	683 people in attendance 108 online meeting unique visitors
Number of Comments Received	37 community surveys 142 mapping comments	16 comment forms 154 mapping comments	53 comment forms 249 mapping comments 38 online comment forms	126 comment forms 91 mapping comments 23 online comment forms
Primary Feedback Topics (based on number of comments)	1. Development 2. Recreation 3. Natural Resources	1. Housing 2. Agriculture 3. Existing Utilities	1. Housing 2. Agriculture 3. Land	1. Housing 2. Agriculture 3. Land

3.4. Involvement of Federal, State, and Local Officials

Minnesota Power has also met with State and Federal agencies individually to begin to understand their environmental review requirements, permitting and mitigation strategies (see Section 3.5) and to discuss the Project's schedule and process as relevant to that agency.

Table 3.4 lists the agencies that Minnesota Power met with between June 2012 and September 2013. An all agency meeting was held in December 2012 to provide a project update and to begin the inter-agency discussions for the Project. In all, 15 government agencies have attended at least one Project meeting prior to the filing of this Application.

Table 3.4. Summary of Agency Meetings through September 2013

Agency	Meeting Date(s)
Advisory Council on Historic Preservation	December 11, 2012
MN Public Utilities Commission	June 6, 2012, December 11, 2012, and June 14, 2013
MN Department of Transportation	June 20, 2012 & December 11, 2012
MN Department of Natural Resources	June 26, 2012, December 11, 2012, March 21, 2013 and August 30, 2013
MN Department of Commerce	July 12, 2012, September 4, 2012, December 11, 2012, June 14, 2013 and September 16, 2013
MN Department of Agriculture	September 5, 2012
MN Pollution Control Agency	September 4, 2012
MN State Historic Preservation Office	October 2, 2012
US Department of Energy	December 11, 2012 and September 16-19, 2013
US Army Corps of Engineers	June 7 and December 11, 2012, April 22, August 8, 2013 and September 17, 2013
US Fish and Wildlife Service	June 20, 2012 and December 11, 2012
US Forest Service - Chippewa National Forest	October 30, 2012 and December 11, 2012
US Department of Agriculture – Natural Resources Conservation Services	December 11, 2012
US Environmental Protection Agency	December 11, 2012
US Bureau of Indian Affairs	October 2, 2012

In addition to the agency meetings listed above, Minnesota Power began holding monthly agency conference calls in February 2013 to provide updates on the project, gather feedback on the routing process and to facilitate interagency coordination as the project develops. Twenty-eight staff from seven state agencies and seven federal agencies have been invited to participate on the calls along with MISO representatives.

On July 2, 2013, Minnesota Power filed its Letter of Intent to Submit a Presidential Permit Application for the Project ("LOI") with the United States Department of Energy ("DOE"). The LOI is attached as Appendix F and was previously e-filed in this docket. As indicated in the LOI, Minnesota Power intends to submit a full Presidential Permit application to the DOE and a Route Permit application to the Commission in early 2014. Minnesota Power will continue to facilitate interagency discussions to enhance coordination and collaboration amongst federal, state, local and tribal governments, non-governmental organizations and the public.

3.5. Listing of Other Permits and Approvals

Table 3.5 provides a summary of the likely permits and approvals that will be needed for the Project.

Table 3.5. Anticipated Federal, State and Local Permits, Approvals and Consultations for the Project

Jurisdiction	Permit/Approval/Consultation
FEDERAL	
Army Corps of Engineers	Clean Water Act Section 404 – Wetlands
Army Corps of Engineers	Clean Water Act Section 10 – Navigable Waters
Bureau of Land Management	To be determined through consultation
Customs and Border Protection	Reviewed as part of NEPA process; Need for additional permitting to be determined

Jurisdiction	Permit/Approval/Consultation
Department of Agriculture – Farm Service Agency	Conservation Reserve Program (CRP) or Conservation Reserve Enhancement Program (CREP) Crossing Coordination
Department of Energy	NEPA Environmental Impact Statement (EIS) Record of Decision
Department of Energy	Presidential Permit
Department of Energy	Section 106 Consultation; Programmatic Agreement
Environmental Protection Agency	Section 401 Permit (if crossing tribal lands)
Federal Aviation Administration	Part 7460 review - Parts 1 & 2 (Obstruction Evaluation/Airport Airspace Analysis)
U.S. Fish & Wildlife Service	Migratory Bird Treaty Act Consultation
U.S. Fish & Wildlife Service	Bald & Golden Eagle Protection Act Incidental Take Permit
U.S. Fish & Wildlife Service	Section 7 of Endangered Species Act
National Park Service	Land and Water Conservation Fund Act, Permission to cross LWCF properties
Natural Resource Conservation Service	NRCS Conservation Easement Program approvals

STATE	
Public Utilities Commission	MN Certificate of Need
Public Utilities Commission	MN Route Permit
Board of Water and Soil Resources	RIM Easement Releases (Coordination with landowners)
Board of Water and Soil Resources	Local/State/Federal Application for Water/Wetland Projects – Public Waters Work Permit
Department of Agriculture	Agriculture Impact Mitigation Plan – Implementation/ Oversight/Coordination
Department of Natural Resources	Local/State/Federal Application for Water/Wetland Projects – Public Waters Work Permit
Department of Natural Resources	License to Cross Public Waters License to Cross State Lands (May also require coordination with National Park Service for land crossings)
Department of Natural Resources	Coastal Zone Management Consistency Determination
Department of Natural Resources	Minnesota Endangered Species Act Coordination/Consultation
Department of Transportation	Utility, Drainage, Driveway, Overweight/Oversized Permits
Pollution Control Agency	National Pollution Discharge Elimination System Permit (Stormwater)

Pollution Control Agency	Section 401 Clean Water Act Permit
State Historic Preservation Office	National Historic Preservation Act and Minnesota Historic Sites Act
LOCAL	
Local Governmental Units (LGUs)	Exemption or No Loss Determination (under the Wetland Conservation Act) Road Crossing/Right-of-way Permits Lands Permits Building Permits Overwidth Load Permits Driveway Access Permits
TRIBES	
Indian Tribes and other Consulting Parties	Section 106 Consultation

4. PROJECT DESCRIPTION

4.1. Overview and Associated Facilities

The Project includes the construction of a new 500 kV transmission line in Minnesota from the United States/Canadian border to the Minnesota Power Blackberry Substation in the Grand Rapids, Minnesota area (the "500 kV Line"), providing 750 MW of transfer capability. The 500 kV Line will be approximately 235-270 miles in length, subject to final route approval by the Commission, and will be constructed on a 200 foot wide right of way. The Minnesota counties likely to be impacted by the construction of the 500 kV Line (depending on final route selection) include: Beltrami, Clearwater, Itasca, Kittson, Koochiching, Lake of the Woods, Marshall, Roseau, and Pennington.

The 500 kV Line will be part of a new 500 kV international transmission interconnection (the "500 kV Interconnection"). Manitoba Hydro will be constructing the approximately 95 - 130 mile Canadian portion of this new interconnection.

Minnesota Power continues to evaluate several structure types and configurations that will be used for the 500 kV Line, including: a self-supporting lattice tower, a lattice guyed-V structure and a lattice guyed delta structure. Minnesota Power currently estimates approximately 4 to 5 structures per mile of line. The type of structure in any given section of line will be dependent on land type and land use.

The existing Minnesota Power Blackberry 230/115 kV Substation ("Blackberry Substation") will be expanded to accommodate the 500 kV line, 500/230 kV transformation, and all associated 500 kV and 230 kV equipment. Minnesota Power plans to acquire 200 additional acres of property adjacent to the Blackberry Substation to accommodate the interconnection of the Project to the existing northeastern Minnesota transmission system. The Project will also require 500 kV series compensation, which may be located at the expanded Blackberry Substation subject to electrical optimization.

4.2. Type and General Location

4.2.1. Design Voltage

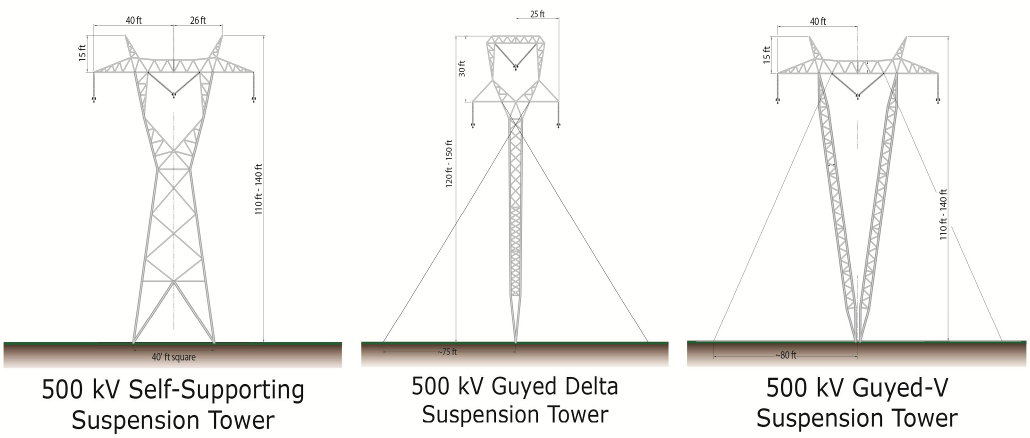
As discussed above, the design voltage of the transmission line for the Project is 500 kV. As discussed further in Section 7.4.2, below, Minnesota Power considered alternative voltages. However, those alternative voltages failed to provide the same overall benefits as the Project.

4.2.2. Number, Sizes and Types of Conductors

Minnesota Power anticipates using 3-conductor bundle 1192.5 kcmil ACSR "Bunting" with 18 inch sub-spacing as the conductor for the 500 kV Line. This conductor is the same as that used on the existing Dorsey - Chisago 500 kV transmission line. Minnesota

Power continues to evaluate several structure types and configurations that will be used for the 500 kV Line, including: a self-supporting lattice tower, a lattice guyed-V structure and a lattice guyed delta structure. Minnesota Power currently estimates approximately 4 to 5 structures per mile of line. The type of structure in any given section of line will be dependent on land type and land use. Figure 4.2.2 illustrates the potential structures.

FIGURE 4.2.2 - Structure Schematics



Typical Spans:
1,000 ft - 1,450 ft

Right-of-way:
200 ft

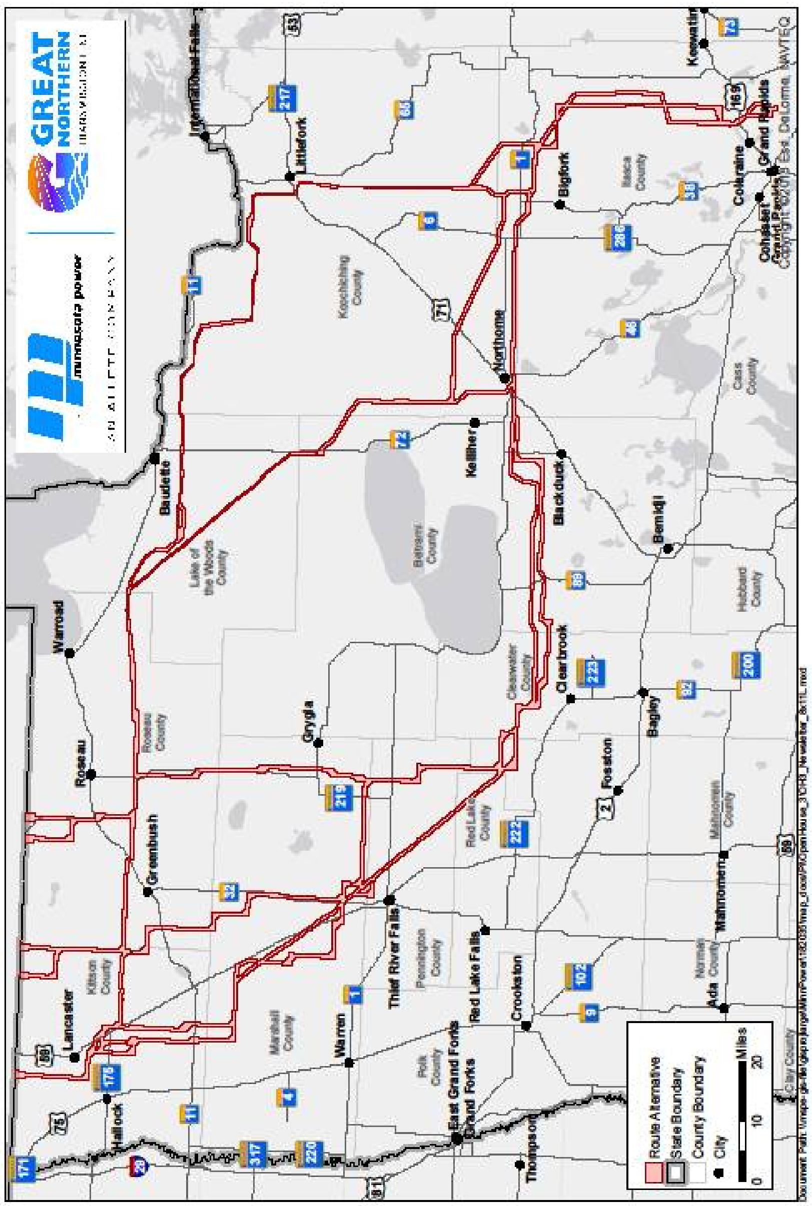
Typical Spans:
1,000 ft - 1,450 ft

Right-of-way:
200 ft

4.2.3. Map

The map in Figure 4.2.3 illustrates the potential routes that have been identified as part of the stakeholder process. Final routes and alternative(s) will be identified as part of the route permit proceeding. The length of the line will depend on the final route selection, but will range from 235 miles to 270 miles.

FIGURE 4.2.3 - Map of Potential Routes



4.3. Cost and Service Characteristics

4.3.1. Total Cost in Current Dollars

The Project will traverse a large section of Northern Minnesota. The geographical topology of Northern Minnesota is very diverse and the route upon which the line will be built has not been determined. Therefore, in order to develop a meaningful estimate, Minnesota Power has developed a "proxy route" that engineers could review and apply design standards to. The result of this process is an estimate based on a proxy route of 240 miles. Minnesota Power estimates that construction of the Project on this proxy route, including substation construction, will cost between $406 million and $609 million (2013 dollars), with a mid-point of $507 million. This range divided by the proxy route of 240 miles will generate a total cost per mile of approximately $1.7 to $2.5 million.

The major components of the above estimates are shown in Table 4.3.1, below.

Table 4.3.1: Project Cost Estimates

	GNTL Project Estimates (2013 Dollars)		
Project Components	Low End (in Millions)	Mid Point (in Millions)	High End (in Millions)
Project Management & Engr	$ 75.3	$ 94.1	$ 112.9
Land and Clearing	$ 53.1	$ 66.4	$ 79.7
Transmission Line Construction	$ 235.6	$ 294.6	$ 353.5
Substation Construction	$ 42.2	$ 52.7	$ 63.3
Project Totals	$ 406.2	$ 507.8	$ 609.3
Based on 240 Miles Dollars per M	$ 1.692	$ 2.116	$ 2.539

4.3.2. Service Life

Minnesota Power has submitted to the Minnesota Public Utilities Commission its 2013 Transmission Plant Depreciation Study (Docket No. E-015/D-13-252). Included in that study Minnesota Power has requested a 55 year life be established for certain transmission line assets and a 44 year service life for substation equipment. If approved, those service lives would apply to the Project's 500 kV line and the substation assets. As a practical matter, a 500 kV line and substation equipment is rarely completely retired, but is repaired, replaced or upgraded to meet future needs.

4.3.3. Average Annual Availability

Transmission assets have very few mechanical elements and will be built to withstand severe weather extremes. Transmission assets are controlled by computer based protection and outages should be momentary. Scheduled maintenance outages also are very infrequent. As a result, the average annual availability of transmission assets is very high, near or above 99%.

4.3.4. Estimated Annual Operations and Maintenance Costs in Current Dollars

Transmission lines require a minimal amount of routine maintenance. The primary annual maintenance expense for transmission line is aerial inspection. These inspections will look for broken insulators or structural defects which could compromise the line. If issues are identified, ground crews will be dispatched to correct the defect. In addition to structural maintenance the right-of-way also must be kept clear of vegetation. Vegetation control is performed on a scheduled and routine basis. Additional vegetation management will also be performed if the aerial inspection discovers issues. The cost for routine maintenance will depend on the topology of the terrain and the type of maintenance required, but typically will run from $1,100 to $1,600 per mile.

Transmission facilities require a certain amount of maintenance to keep them functioning in accordance with good utility practices, manufacturers' recommendations and North American Electric Reliability Corporation ("NERC") standards.

4.3.5. Estimate of Effect on Rates System-Wide and in Minnesota

Minnesota Power recognizes the value and importance of affordable rates in all customer classes. While the Project will impact the rates that Minnesota Power charges both its retail and wholesale customers, Minnesota Power and Manitoba Hydro have taken steps to minimize that impact.

As part of the 938 Docket, Minnesota Power indicated that a 230 kV transmission option for the delivery of 250 MW Agreements from Manitoba Hydro would cost Minnesota Power (and by extension, its customers) from $200 to $240 million (2020 dollars). In addition, Minnesota Power and its customers would bear the full maintenance costs associated with such a line.

In contrast, as discussed in Section 3.1 above, Minnesota Power will be asking its customers to be responsible for only one-third of the Project cost, corresponding to the portion of the line needed for the delivery of the 250 MW Agreements. Using the Project cost estimates provided in Section 4.3.1, escalated to 2020 dollars, Minnesota Power's customers' revenue requirements would be based on an investment of \$164 to \$245 million. In order to provide a meaningful comparison, the rate impacts were based on an investment at the midpoint of the above 2020 range, or \$204.5 million, compared to a midpoint range of the 230 kV estimates of \$220 million, representing a cost reduction of approximately ten percent (10%) from the transmission cost in the 938 Docket. Going forward, Minnesota Power customers will also be responsible for only one-third of the maintenance costs associated with the Project. As such, the Project provides a more cost-effective and longer-term solution for Minnesota Power ratepayers than constructing the 230 kV option.

The effect of the Project on rates will be discussed in two sections. The first will be the effect on Minnesota Power's retail rates and the second will be the effect on FERC (MISO) jurisdictional rates.

4.3.5.1. Minnesota Power Retail Rates

The Project is project to have an effect on the rates of Minnesota Power's retail customers. Table 4.3.5.1 summarizes the estimated Minnesota jurisdictional revenue requirements and rate impacts by customer class for the expected in-service year beginning June 1, 2020. The Minnesota jurisdictional and class requirements were derived by multiplying the total Minnesota Power customer revenue requirements by Minnesota Power's current D-02 Transmission Demand jurisdictional and class allocators. For the average residential customer, the rate impact in 2020 would be approximately \$2.51 per month. If compared to the estimated average current residential rate in 2014, this would represent an increase of approximately 3.3 percent. By 2020, however, the percent increase is expected to be lower because base rates will likely increase as other system costs change and are incorporated into base rates through future rate cases and other mechanisms. For Large Power customers, the estimated rate impact for the year 2020 would be approximately 0.261¢ per kWh of energy. If compared to the estimated average current Large Power rate for 2014, this would represent an increase of approximately 4.9 percent. As with residential rates, the percent increase is expected to be lower by 2020 because base rates will likely increase due to changes in other system costs that will be incorporated into base rates through future rate cases and other mechanisms. These estimates would also be impacted by future changes in Minnesota Power's D-02 Transmission Demand jurisdictional and class allocators.

Table 4.3.5.1: Estimated Retail Customer Impact[16]

For the twelve months ending	**5/31/2021**
MN Jurisdictional Revenue Requirements	$25,088,852
Rate Class Impacts	
Residential	
Average Current Rate (¢/kWh)	9.403
Increase (¢/kWh)	0.309
Increase (%)	3.29
Avg Impact ($/month)	2.51
General Service	
Average Current Rate (¢/kWh)	9.398
Increase (¢/kWh)	0.287
Increase (%)	3.05
Avg Impact ($/month)	7.97
Large Light & Power	
Average Current Rate (¢/kWh)	7.494
Increase (¢/kWh)	0.259
Increase (%)	3.46
Avg Impact ($/month)	590.32
Large Power	
Average Current Rate (¢/kWh)	5.299
Increase (demand + energy combined) (¢/kWh)	0.261
Increase (%)	4.93
Avg Impact ($/month)	144,968

[16] Average current rates are 2014 estimated rates based on Final General Rates in 2009 Rate Case without riders and other revenues (E-015/GR-09-1151) adjusted to include current rider rates. Current rider rates include Renewable Resources Rider rate, Transmission Cost Recovery rate, current 2013 Conservation Program Adjustment ("CPA") rate and estimated 2014 Fuel and Purchased Energy ("FPE"). Average $/month impact based on 2014 budgeted billing units.

Municipal Pumping	
Average Current Rate (¢/kWh)	8.564
Increase (¢/kWh)	0.428
Increase (%)	5.00
Avg Impact ($/month)	51.89
Lighting	
Average Current Rate (¢/kWh)	15.090
Increase (¢/kWh)	0.323
Increase (%)	2.14
Avg Impact ($/month)	0.47

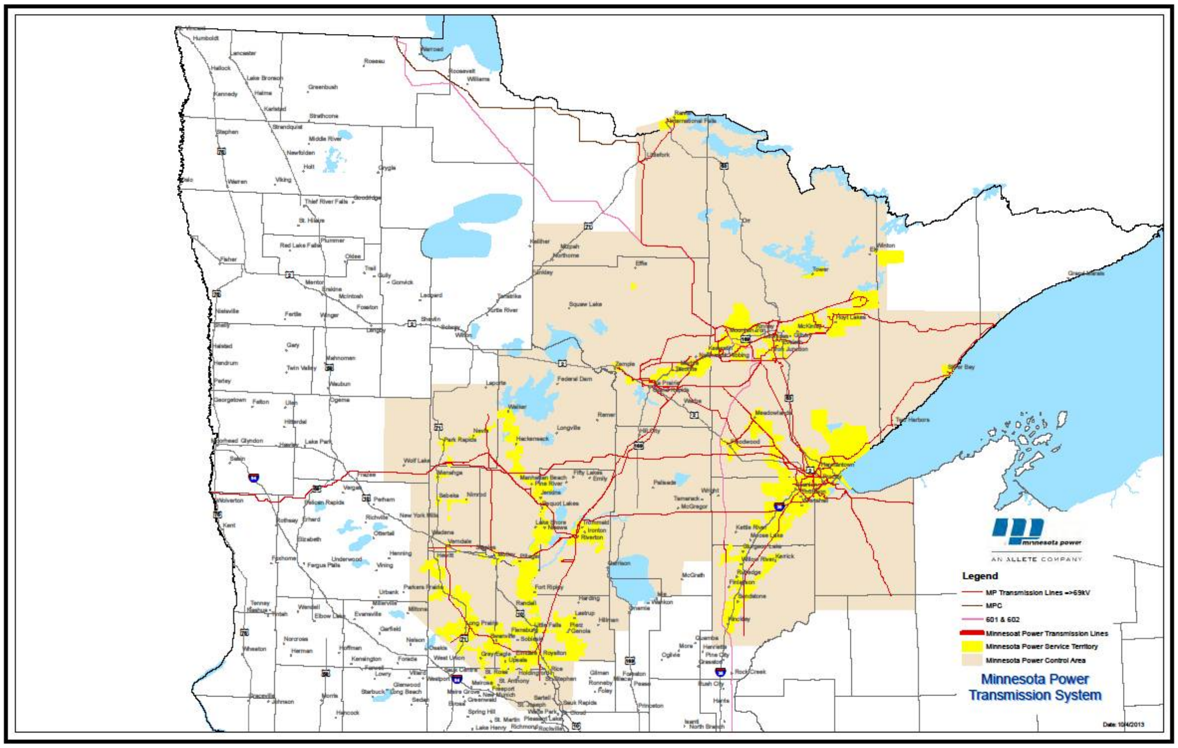
4.3.5.2. FERC (MISO) Jurisdictional Rates

Minnesota Power, as a Transmission Owner in MISO, develops transmission rates annually through the completion of the MISO Attachment O. Attachment O is a FERC-approved formula rate template used by all MISO Transmission Owners to develop transmission rates. MISO uses these rates to establish a price that MISO Market Participants could expect to pay when they utilize transmission service provided by MISO. The Project is one of the largest transmission projects ever undertaken in Minnesota and will have an impact on MISO rates. The Project will add $26.4 million in MISO revenue requirements in the first year of operation to the Minnesota Power load zone. In contrast, if Minnesota Power would construct a stand-alone 230 kV project, a 230 kV project would add $34.5 million in addition revenue requirements to Minnesota Power's MISO rates. The Project has the potential of reducing Minnesota Power MISO rates by 9.3% over a stand-alone 230 kV build. The Project is not currently eligible for MISO cost allocation and instead will be fully funded under a participant pays model.

Minnesota Power supplies power to full requirement municipal customers based on a standardized power supply formula rate under FERC's market based rate authority. Municipal customers also pay the FERC approved transmission rate under the annually filed MISO Attachment O plus unbundled ancillary services. Minnesota Power's municipal customers 2014 total estimated increase is 3.81% based on a 2014 in-service (recognizing the Project is scheduled to be in-service by 2020).

4.4. Map of Applicant's System or Load Center to be Served

FIGURE 4.4 – Minnesota Power System and Load Center to be Served



4.5. Estimated System Losses

Losses are a measure of the energy flow across the system that is converted into heat due to resistance within the elements of the transmission system. It is necessary for utilities to provide enough generation to serve their respective system demands (plus reserves), taking into account the loss of the energy before it can be usefully consumed. When system losses are reduced or minimized, electrical energy is delivered to end users more efficiently, helping to defer the need to add more generation resources to a utility's portfolio. Therefore, system loss reduction results in monetary savings in the form of less fuel required to meet the system demand plus delayed capital investment in generation plant construction.

In determining the amount of losses associated with a particular project, it is not reasonable to consider only the Project's transmission facilities and calculate losses directly from operation of that transmission. It is necessary to look at the total losses of the system that result with and without the proposed project. In its Exemption Order, the Commission authorized the Company to provide line loss data for the system as a whole, rather than line loss data specific to an individual transmission line. In this case, the Company considered the MISO West Planning Region, a large area served by a number of utilities in the Dakotas, Minnesota, Iowa, Wisconsin, and Upper Michigan, to determine the resulting effect of the Project's transmission facilities on system losses.

Power Flow analysis was used to calculate the losses at peak demand based on the MISO Transmission Expansion Plan ("MTEP") MTEP13 Reliability Analysis 2023 Summer Peak Model, with no incremental transfers from Manitoba to the United States. The results are shown below in Table 4.5.

Table 4.5: Calculated Peak Loss Savings

Scenario	System Losses (MW)
Existing Transmission System	1142.2
System with Project	1121.1
Difference	-21.1

The table shows that the Project's proposed transmission infrastructure reduces the losses on the electrical system. Under summer peak demand conditions with no incremental Manitoba – United States transfers, the losses incurred in the MISO West Planning Region are 21.1 MW less when the Project is energized as compared to the existing system configuration, in essence delivering an estimated 21.1 MW of zero emission efficiency energy.

Because demand for electric power is not constant and losses are related to the square of the current flowing through the transmission lines in the electric system, the losses will change over time, increasing as demand increases and decreasing as demand decreases. Because losses change over time, there is no precise method to calculate average annual loss reductions. One common method is to use the loss savings at peak demand to estimate the average annual loss savings based on the following formulas:[17]

$$Loss\ Factor = (0.3 \times Load\ Factor) + (0.7 \times Load\ Factor^2)$$

$$Annual\ Loss\ Savings\ (MWh) = (Loss\ Factor \times Peak\ Loss\ Savings) \times 8760\ hours/year$$

[17] Gönen, Turan. *Electric Power Distribution System Engineering.* McGraw Hill, 1986, pp. 55, 58-59.

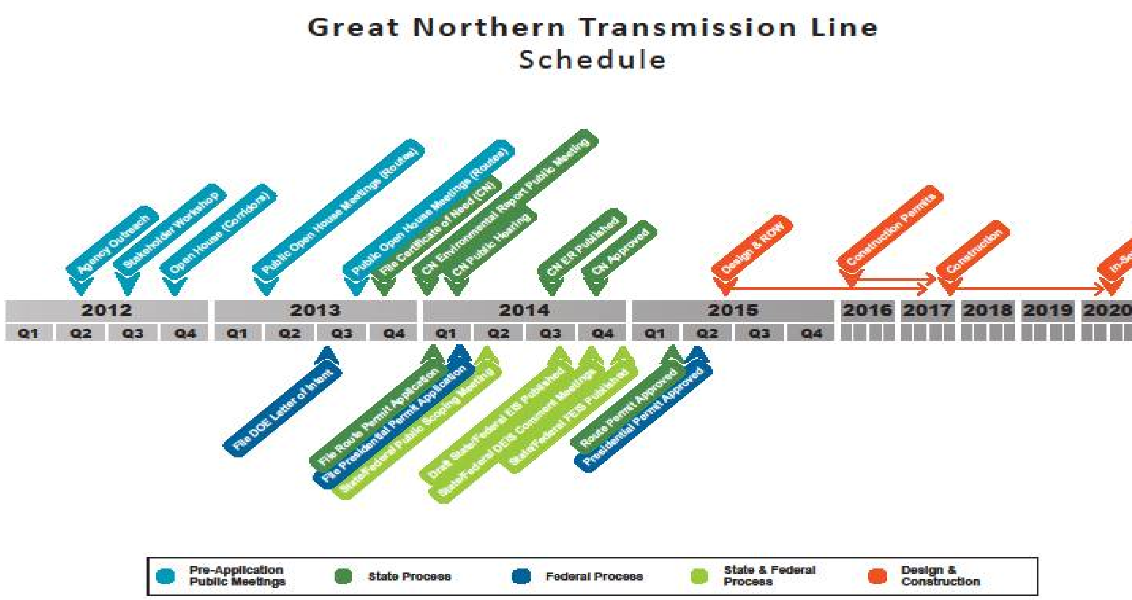
Assuming a MISO load factor of 60 percent and using the calculated loss savings at peak demand (given in Table 4.5), the Project will reduce average transmission losses by an estimated 79,849 MWh annually.

5. PROJECT CONSTRUCTION, MAINTENANCE AND OPERATION

5.1. Project Schedule and Sequencing, Including Property Acquisition and Width of Right-of-Way Required

The in-service date for the proposed Project is June 1, 2020. Minnesota Power anticipates that the State of Minnesota, as part of the Route Permit process, will develop a state Environmental Impact Statement ("EIS") for the Project, in compliance with MN Rules 7849.5300. Likewise, the Department of Energy ("DOE"), through the Presidential Permit process, will prepare a Federal EIS to assess the environmental impacts of the Project, in compliance with the National Environmental Policy Act and DOE's implementing regulations, 10 CFR Part 1021. Minnesota Power further anticipates that the environmental impacts from the Project will be reviewed by numerous agencies and the public during preparation of the state and federal EISs and during the federal and state permitting processes. In addition, DOE and the Department are exploring the option of a shared scoping process and joint federal/state EIS but no formal agreement has yet been reached.

The anticipated schedule for the state and federal environmental review processes is illustrated in Figure 5.1. **FIGURE 5.1**



The schedule allows for two years of environmental review, one year for final design, easement negotiation/acquisition and permitting, and three years for construction and restoration.

The 500 kV line is expected to require a 200-foot-wide right-of-way. Minnesota Power will work with private landowners to negotiate the terms of an easement acquisition that will be acceptable to both parties. Normally, right-of-way discussions will begin during the detailed design phase of the project, when a final route has been selected. For the transmission line, Minnesota Power will acquire an easement across the parcel to accommodate the facility. The land evaluation and acquisition process will include a title search, contact with the landowner, survey, real estate document preparation, negotiation and purchase agreement.

As part of the acquisition process, Minnesota Power's right-of-way agents will discuss the construction schedule and construction requirements with the owner of each parcel. Special considerations may be discussed and included in the easement agreement, such as temporary or permanent gates, fencing, crops and livestock accommodations. Experience with siting lines has shown that, in nearly all cases, the utility company is able to work with landowners to address their concerns and an agreement is reached for the purchase of the easement. Documents required for the purchase may include an easement, purchase agreement, contract and deed.

In rare instances, a negotiated settlement cannot be reached and the landowner may choose to have an independent third-party determine the value of the easement. This valuation is made through the utility's exercise of the right of eminent domain per Minnesota Statutes Chapter 117. This process is known as condemnation. The condemnation process begins at the district court, which appoints a three-person condemnation commission if the condemnation petition is granted. The condemnation commission would then hold a valuation hearing, where the utility and landowner can testify as to the fair market value of the easement. The condemnation commission then makes an award as to the value of the property and files it with the court.

At the Blackberry Substation, new land will be acquired to accommodate project facilities. Property for the substation will be purchased outright, rather than as an easement. The procedure for land acquisition will be similar to that stated above for transmission line right-of-way. Minnesota Power has entered a purchase option agreement with the owner of the property adjacent to the Blackberry Substation. Execution of a land purchase at this location will provide a definite end point for the route, which will be addressed in the Route Permit and Presidential Permit processes.

5.2. Construction, Mitigation and Restoration Practices, Including Workforce Required

5.2.1. Transmission Line

Standard construction and mitigation practices developed from experience with past projects as well as industry-specific Best Management Practices ("BMPs") will be employed. BMPs address right-of-way clearance, erecting transmission line structures, and stringing transmission lines. BMPs for the Project will be based on the specific construction design, prohibitions, maintenance guidelines, inspection procedures, and other activities involved in constructing the line. In some cases these activities, such as schedules, are modified to incorporate a BMP for construction that will assist in minimizing impacts on sensitive environments. For instance in areas where construction occurs close to waterways, BMPs are employed to help prevent soil erosion and ensure that equipment fuel and lubricants do not enter the waterway.

Post-construction reclamation activities will include removing and disposing of debris, removing all temporary structures (including staging and laydown areas), employing appropriate erosion control measures, reseeding areas disturbed by construction activities with vegetation similar to that which was removed within certain height restrictions to prevent interference with the line using a seed mixture certified as free of noxious or invasive weeds, and restoring the areas to their original condition to the extent possible. In cases where soil compaction has occurred, the construction crew or a restoration contractor uses various methods to alleviate the compaction, or as negotiated with landowners.

Once restoration procedures are completed, Minnesota Power will contact affected landowners to determine if the clean-up measures have been to their satisfaction and if any other damage may have occurred. If damage has occurred to crops, fences, or other property, Minnesota Power will compensate the landowner.

5.2.2. Substation

The substation upgrades involve adding new equipment, modifying existing equipment, or replacing existing equipment with new equipment. Construction work will occur on adjacent property near the existing Blackberry Substation.

The substation will be constructed/upgraded in compliance with the applicable requirements of the National Electrical Safety Code, Occupational Safety and Health Act, and state and local regulations. Designs will be completed by Minnesota licensed experienced and proficient engineers. Contractors will be committed to safe working practices. The final design of the substation upgrades will take the local conditions of the substation sites into consideration, and where warranted will include safety provisions beyond the minimum requirements established in the various applicable safety codes.

The substation upgrades will be designed to allow future maintenance to be done with the minimum impact on substation operation and the necessary clearance from energized equipment to ensure safety.

Standard construction and mitigation practices developed from experience with past projects as well as industry-specific BMPs will be employed. BMPs for the Project will be based on the specific construction design, prohibitions, maintenance guidelines, inspection procedures, and other activities involved in constructing the substations. In some cases these activities, such as schedules, are modified to incorporate a BMP for construction that will assist in minimizing impacts on sensitive environments. For instance in areas where construction occurs close to waterways, BMPs are employed to help prevent soil erosion and ensure that equipment fuel and lubricants do not enter the waterway.

Upon the completion of construction activities, Minnesota Power will restore the remainder of the site. Post-construction reclamation activities will include removing and disposing of debris, removing all temporary structures (including staging areas), and employing appropriate erosion control measures. If areas outside the substation's fence line are disturbed by construction activities, they will be reseeded with vegetation similar to that which was removed, within certain height restrictions to prevent interference with the substation and the transmission lines entering the substation.

5.2.3. Work Force Required

The work force required for construction of the Project's facilities is estimated to be over 200 people per year. This includes tree trimming crews, transmission line construction workers, substation upgrade construction workers, safety supervisors, environmental support, and other on- and off-site support staff. Minnesota Power will work with local governments in the Project area to meet any specific local employment obligations. There will also be a need for additional contracted professional services related to line and substation design.

It is not expected that additional permanent jobs will be directly created by construction of the Project. The construction activities will provide, however, a seasonal influx of additional dollars into the communities during the three-year construction phase, with construction materials purchased from local vendors where feasible. Minnesota Power contracted with the Labovitz School of Business and Economics (Bureau of Business and Economic Research) at the University of Minnesota Duluth to conduct an economic impact study on the Project (the "Labovitz Study"). The Labovitz Study shows that construction of the Project will generate over $850 million in economic impact in northern Minnesota for the design and construction period of 2016 through 2020.[18] The study report is attached as Appendix L.

5.3. Operations and Maintenance Practices

5.3.1. Transmission Line

Access to the right-of-way of a completed transmission line is required periodically to perform inspections, conduct maintenance, and repair damage. Regular maintenance and inspections will be performed during the life of the facility to ensure its continued integrity. Generally, 500 kV lines are inspected annually for problems by foot, ATV, truck, snowmobile, or by air. Inspections are limited to the right-of-way and to those areas where obstruction or terrain may require off-right-of-way access. If problems are found during inspection, repairs are performed and the landowners compensated for any losses incurred.

The right-of-way is managed to remove vegetation that interferes with the operation of the line. Vegetation maintenance for 500 kV lines is typically on a two to five year cycle. Right-of-way clearing practices include a combination of mechanical and hand clearing, along with herbicide application where allowed, to remove or control vegetation growth. The structures for the line will be new, so very little maintenance is expected for many years.

5.3.2. Substation

Over the life of the substation, inspections will be performed regularly to maintain equipment and make necessary repairs. Routine maintenance will be conducted as required to remove undesired vegetation that may interfere with the safe and reliable operation of the substation.

5.4. Additional Human and Environmental Impact Considerations

5.4.1. Electric and Magnetic Fields, Stray Voltage

Electric and magnetic fields are invisible lines of force that are present anywhere electricity is produced or used, including around electric appliances and any wire that is conducting electricity. The term EMF is typically used to refer to electric and magnetic fields that are coupled together. For the lower frequencies associated with power lines (referred to as "extremely low frequency" or ELF), electric and magnetic fields are relatively decoupled and should be described separately in terms of kilovolts per meter (kV/m) and milliGauss (mG), respectively.

[18] The Labovitz Study is attached as Appendix L.

5.4.1.1. Electric Fields

Voltage on any wire (conductor) produces an electric field in the area surrounding the wire. The electric field associated with a HVTL extends from the energized conductors to other nearby objects, such as the towers, buildings, and vehicles. The intensity of electric field associated with a HVTL is proportional to the voltage of the line, and becomes weaker with increasing distance from the line conductors. Nearby trees and building material also greatly reduce the strength of HVTL electric fields. The electric field is expressed in units of voltage density, expressed as volts per meter (V/m) or kilovolts per meter (kV/m).

When an electric field reaches a nearby conductive object, such as a vehicle or a metal fence, it induces a voltage on the object. The magnitude of the induced voltage is dependent on many factors, including the object's capacitance, shape, size, orientation, location, resistance to ground, and the weather conditions. If the object is insulated or semi-insulated from the ground and a person touches it, a small current would pass through the person's body to the ground. This might be accompanied by a spark discharge and mild shock, similar to what can occur when a person walks across a carpet and touches a grounded object, like a door knob, or another person.

The main concern with induced voltage on an object is not the level of induced voltage, but the current that flows through a person to the ground when the person touches the object. To ensure that any discharge associated with induced voltage due to a HVTL does not reach unsafe levels, the National Electric Safety Code ("NESC") requires that any discharge be less than 5 milliAmperes (mA). Based on the maximum calculated intensity of electric field shown in Table 5.4.1.1 below, Minnesota Power has calculated the approximate spark discharge from a typical school bus (40 ft. long × 8.5 ft. wide × 10.75 ft. high) stopped at mid-span under a 500 kV line. The modeling shows that the spark discharge current would be approximately 3.75 mA, which is within limits of the levels that have been deemed safe by the NESC. Minnesota Power would ensure that any fixed object, such as a fence or other large permanent conductive object in close proximity to, or parallel to the line, would be grounded to further reduce the likelihood of shock hazard associated with induced voltage from the HVTL.

While there is no official state or federal standard for transmission line electric fields, the Environmental Quality Board ("EQB") had historically enforced a maximum electric field limit of 8 kV/m measured at one meter above the ground for transmission line projects. This limit was designed, consistent with the NESC spark discharge limit, to prevent serious hazard from shocks when touching large objects placed under AC transmission lines of 500 kV or greater. As stated above and demonstrated in Table 5.4.1.1 below, the proposed facilities will comply with the NESC and EQB standards.

Minnesota Power retained a consultant to calculate the predicted intensity of electric field associated with the various structure configurations of the Project. The results are given in Table 5.4.1.1 for the edge of the right-of-way (100 feet from centerline) and at the location where the maximum electric field will be experienced.

Table 5.4.1.1: Predicted Intensity of Electric Fields at Maximum Operating Voltage

Structure Type	Edge of Right-of-Way	Maximum Overall	
	E-Field Intensity (kV/m)	E-Field Intensity (kV/m)	Distance from ROW Centerline (ft.)
500 kV Single Circuit Guyed Delta Tower	1.330	6.613	31.2
500 kV Single Circuit Self-Supporting Tower	2.325	7.122	43.8
500 kV Single Circuit Guyed-V Tower	2.325	7.122	43.8

Values were calculated by Minnesota Power's consultant using Bonneville Power Administration's Corona and Field Effects Program, Version 3.0. Because electric fields are particularly dependent on the voltage of the transmission line, the values below were calculated at the line's maximum operating voltage. Maximum operating voltage is defined for the Project as the nominal voltage plus ten percent, in this case 550 kV. Per IEEE Standard 644-1994 (R2008), *IEEE Standard Procedures for Measurement of Power Frequency Electric and Magnetic Fields From AC Power Lines*, values were calculated at minimum conductor-to-ground clearance (mid-span) at a height of one meter above ground.

Other potential impacts of electric fields include interference with the operation of pacemakers and Implantable Cardioverter/Defibrillators ("ICDs"). Interference with implanted cardiac devices can occur if the electric field intensity is high enough to induce sufficient body currents to cause interaction. In general, the response depends on the make and model of the device as well as the individual's height, build, and physical orientation with respect to the electric field. Pacemaker manufactures like Medtronic and Guidant have indicated that modern cardiac devices are much less susceptible to interactions with electric fields than older "unipolar" designs. A recent study (Scholten et al. 2005) concludes that the risk of interference inhibition of unipolar cardiac pacemakers from high voltage power lines in everyday life is small. In 2007, Minnesota Power and

Xcel Energy conducted studies with Medtronic to evaluate the impact of the electric fields associated with existing 115 kV, 230 kV, 345 kV, and 500 kV transmission on implantable medical devices. The analysis was based on real life public exposure levels under actual transmission lines in Minnesota; no adverse interaction with pacemakers or ICDs occurred (University of Minnesota Power Systems Conference Proceedings 2007). The analysis concluded that, although interaction may be possible in unique situations, device interaction due to typical public exposure would be rare.

In the unlikely event a pacemaker is impacted, the effect is typically a temporary asynchronous pacing. The pacemaker would return to its normal operation when the person moves away from the source of the interference.

5.4.1.2. Magnetic Fields

Current passing through any conductive material, including a wire, produces a magnetic field in the area around that material. The current flowing through the conductors of a HVTL generates a magnetic field that, in similar fashion to the electric field, extends from the energized conductors to nearby objects. The intensity of the magnetic field associated with a HVTL is proportional to the amount of current flowing through the line conductors, and rapidly weakens with increasing distance from the line conductors. Unlike electric fields, magnetic fields are not significantly affected by the presence of trees, buildings, or other solid structures nearby. The magnetic field is expressed in units of magnetic flux density, expressed as Gauss (G) or milliGauss (mG).

The question of whether exposure to power-frequency (60 Hertz ("Hz")) magnetic fields can cause biological responses or adverse health effects has been the subject of considerable research for the past three decades. The most recent and exhaustive reviews of the health effects from power-frequency fields conclude that the evidence of health risk is minimal. The National Institute of Environmental Health Sciences ("NIEHS") issued its final report, NIEHS Report on *Health Effects from Exposure to Power-Line Frequency Electric and Magnetic Fields*, on June 15, 1999, following six years of intensive research (NIEHS 1999). In the report, the NIEHS concluded that the scientific evidence linking EMF exposures with health risks is weak and that this finding does not warrant aggressive regulatory concern. However, in light of the weak scientific evidence supporting some association between EMF and health effects and the fact that exposure to electricity is common in the United States, the NIEHS stated that passive regulatory action, such as providing public education on reducing exposures, is warranted.

The United States Environmental Protection Agency (US EPA 2013) has come to a similar conclusion about the link between adverse health effects, specifically childhood leukemia, and power-frequency EMF exposure. On its website, the EPA states:

> Many people are concerned about potential adverse health effects. Much of the research about power lines and potential health effects is inconclusive. Despite more than two decades of research to determine whether elevated EMF exposure, principally to magnetic fields, is related to an increased risk of childhood leukemia, there is still no definitive answer. The general scientific consensus is that, thus far, the evidence available is weak and is not sufficient to establish a definitive cause-effect relationship.

Minnesota, California, and Wisconsin have each conducted their own literature reviews or research to examine this issue. In 2002, Minnesota formed an Interagency Working Group to evaluate the research and develop policy recommendations to protect the public health from any potential problems arising from EMF effects associated with HVTLs. The Minnesota Department of Health published the Working Group's findings in *A White Paper on Electric and Magnetic Field (EMF) Policy and Mitigation Options* (Minnesota Department of Health 2002). The Working Group summarized its findings as follows:

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

Most recently, results of a large epidemiological study were published presenting the findings of a case-control study that investigated risks of adult cancers in relation to distance and the extremely low-frequency (ELF) magnetic fields from high-voltage overhead transmission lines (Elliot et al. 2013). The study examined National Cancer Registry Data in England and Wales from 1974 – 2008. The data examined included 7,823 leukemia, 6,781 brain/central nervous system, 9,153 malignant melanoma, and 29,202 female breast cancer cases. Case cancers were individuals 17-74 years old diagnosed between 1974 and 2008, and lived within 1,000 meters of a high-voltage overhead transmission line. The transmission lines included in the study were 400 kV, 275 kV, and 132 kV transmission lines across England and Wales. The study also included 79,507 controls frequency-matched on year and region. The controls were individuals selected from a range of cancers not considered to be associated with electric and magnetic fields. They found that the results do not support an epidemiological association of adult cancers with proximity to residential magnetic fields from high-voltage overhead transmission lines.

There are currently no federal guidelines pertaining to magnetic field exposure beneath a HVTL. The Commission has addressed the matter with respect to new transmission lines in a number of separate dockets over the past few years. In its September 12, 2012 Order in MPUC Docket No. E-002/TL-11-800 for the North Rochester to Chester 161 kV transmission line, the Commission approved and adopted the following findings with regard magnetic field exposure:

> 107. There are no State of Minnesota or federal standards for exposure to magnetic fields from transmission lines. Florida, Massachusetts, and New York have established standards for magnetic field exposure at the edge of transmission line rights-of-way. These standards are 150 mG, 85 mG, and 200 mG respectively.
>
> 108. The International Commission on Non-Ionizing Radiation Protection (ICNIRP) has developed standards for magnetic field exposure. The ICNIRP standard for magnetic field exposure for the general public is 2,000 mG.
>
> 109. Epidemiological studies have shown an association between magnetic field exposure and health risks for children. Epidemiological studies, clinical studies, and cellular studies have shown no association between magnetic field exposure and health risks for adults. No studies have established a causal relationship between magnetic field exposure and adverse health impacts.
>
> 110. The estimated magnetic fields for the project are below all standards adopted by other states and below international standards. No adverse health impacts from magnetic fields are anticipated for persons living or working near the project.

As shown in Table 5.4.1.2B, the predicted peak magnetic field at the Project's projected peak loading is below the state standards at the edge of the transmission right-of-way, and well below the ICNIRP standard anywhere under the transmission line. Because the magnetic field produced by the transmission line is dependent on the current flowing on its conductors, the actual magnetic field when the project is placed in service will typically be less than shown in Table 5.4.1.2B. Actual magnetic field levels associated with the line will vary as the power flow on the line varies throughout the day. Since the actual power flow on the line will be less than projected peak levels during most hours of the year, the actual magnetic field levels surrounding the line will also be less than those shown in Table 5.4.1.2B during most hours of the year.

Minnesota Power retained a consultant to calculate the predicted intensity of magnetic field associated with the various structure configurations of the Project. The results are given in Tables 5.4.1.2A & 5.4.1.2B for the edge of the right-of-way (100 feet from centerline) and at the location where the maximum magnetic field will be experienced. Values were calculated by Minnesota Power's consultant using Bonneville Power Administration's Corona and Field Effects Program, Version 3.0. Because magnetic fields are particularly dependent on the current flowing on the transmission line, magnetic field information is provided for two conditions: the maximum ampacity of the line (Table 5.4.1.2A) and the projected peak loading when the project is in service (Table 5.4.1.2B).

Maximum ampacity is defined for the Project as the expected capacity of the line, in this case 2,000 Amps. The projected peak loading of the line – 1,024 Amps – was derived from power system modeling of the Project under system normal conditions in a 2020 summer off-peak case with high Manitoba – United States transfers. Per IEEE Standard 644-1994 (R2008), *IEEE Standard Procedures for Measurement of Power Frequency Electric and Magnetic Fields From AC Power Lines*, values were calculated at minimum conductor-to-ground clearance (mid-span) at a height of one meter above ground.

Table 5.4.1.2A: Predicted Intensity of Magnetic Fields at Maximum Ampacity

Structure Type	Edge of Right-of-Way	Maximum Overall	
	B-Field Intensity (mG)	B-Field Intensity (mG)	Distance from ROW Centerline (ft.)
500 kV Single Circuit Guyed Delta Tower	52.94	258.11	0
500 kV Single Circuit Self-Supporting Tower	88.54	293.67	18.8
500 kV Single Circuit Guyed-V Tower	88.54	293.67	18.8

Table 5.4.1.2B: Predicted Intensity of Magnetic Fields at Projected Peak Loading

Structure Type	Edge of Right-of-Way	Maximum Overall	
	B-Field Intensity (mG)	B-Field Intensity (mG)	Distance from ROW Centerline (ft.)
500 kV Single Circuit Guyed Delta Tower	26.81	126.18	0
500 kV Single Circuit Self-Supporting Tower	44.76	144.68	18.8
500 kV Single Circuit Guyed-V Tower	44.76	144.68	18.8

5.4.1.3. Stray Voltage

Stray voltage is a condition that can occur on the electric service entrances to structures from distribution lines – not transmission lines. More precisely, stray voltage is a voltage that exists between the neutral wire of the service entrance and grounded objects in buildings such as barns and milking parlors.

Transmission lines do not, by themselves, create stray voltage because they do not connect to businesses or residences. However, transmission lines can induce stray voltage on a distribution circuit that is parallel and immediately under the transmission line. Appropriate measures would be taken to prevent stray voltage problems when the proposed Project parallels or crosses distribution lines.

5.4.2. Ozone and NOx

Because of a transmission line's electrical characteristics, some chemical reactions occur around conductors in the air. Chemical reactions can occur when corona forms, which can produce ozone and oxides of nitrogen in the air surrounding the conductor. Corona consists of the breakdown or ionization of air within a few centimeters of conductors, which usually occurs because of some imperfection such as a sharp edge or scratch on the conductor.

Ozone is a very reactive form of oxygen molecules and combines readily with other elements and compounds in the atmosphere. Because of its reactivity it is relatively short-lived. Ozone also forms in the lower atmosphere from lightning discharges, and from reactions between solar ultraviolet radiation and air pollutants. The natural production rate of ozone is directly proportional to temperature and sunlight, and inversely proportional to humidity. Thus, humidity or moisture, the same factor that increases corona discharges from transmission lines, inhibits the natural production of ozone. Ozone occurs naturally in the air, with typical rural ambient levels around 10 to 30 parts per billion (ppb) and higher (EPRI 1982). After a thunderstorm the air may contain 50 to 105 ppb of ozone.

Currently, both the State and federal governments have regulations regarding permissible concentrations of ozone and oxides of nitrogen. The State and national ambient air quality standards for ozone are similarly restrictive. The National Ambient Air Quality Standards ("NAAQS") for ozone and nitrogen dioxide is 75 ppb on an eight-hour averaging period (US EPA 2013). The State standard is 80 ppb based upon the fourth-highest eight-hour daily maximum average in one year (Minn. R. 7009.0080). Both averages must be compared to the national and State standards because of the difference averaging periods.

A recent study performed in Lithuania (Valuntaité et al. 2009) found that the ozone concentration near high-voltage lines (330 kV) was 10 to 51 ppb, while the background ozone concentrations in the test areas varied from 10 to 51 ppb. The researchers concluded that the average ozone concentration near high-voltage lines was on average 20 percent higher than the background ozone concentration, and that the most significant impact on different levels of ozone near high-voltage lines and the background concentrations was the result of temperature, wind speed, and relative humidity.

A literature review of ozone studies near transmission lines was conducted. In one study, the results of six measurement programs (studies) concerning the field measurement of ozone from overhead high voltage lines concluded that the lines had no significant effect on ozone concentration in the area (IIT Research Institute 1978). The voltages of the transmission lines studied ranged from 138 kV to 765 kV. The studies were occurred from 1970 – 1973. Three of the studies were conducted by groups not connected with or sponsored by the power industry.

5.4.3. Radio and Television Interference

Generally, transmission lines do not cause interference with radio, television, or other communication signals and reception. While it is rare in every day operations, four potential sources for interference do exist, including gap discharges, corona discharges, and shadowing and reflection effects.

Gap discharge interference is the most commonly noticed form of power line interference with radio and television signals, and also typically most easily fixed. Gap discharges are usually caused by hardware defects or abnormalities on a transmission or distribution line causing small gaps to develop between mechanically connected metal parts. As sparks discharge across a gap, they create the potential for electrical noise, which can cause interference with radio and television signals. The degree of interference depends on the quality and strength of the transmitted communication signal, the quality of the receiving antenna system, and the distance between the receiver and the power line. Gap discharges are usually a maintenance issue, since they tend to occur in areas where gaps have formed due to broken or ill-fitted hardware (clamps, insulators, brackets). Because gap discharges are a hardware issue, they can be repaired relatively quickly once the issue has been identified. While gap discharges and their effects can happen on power lines of all voltage levels, they typically occur on lower voltage distribution lines. The gap discharge potential of larger transmission lines, like the Project, tends to be minimized because there are fewer structures and a higher mechanical load on hardware.

Corona from transmission line conductors can also generate electromagnetic noise at the same frequencies that radio and television signals are transmitted. Most often the reasons for corona discharge are related to irregularities on conductors, including scratches and nicks, dust buildup, or water drops. Corona discharges are generated when localized electric fields near an energized conductor produce small electric discharges, ionizing nearby air. The air ionization cause by corona results in energy loss and generates audible noise, radio noise, light, heat, and small amounts of ozone. The energy loss from corona is minimized largely through the design process by selecting an appropriate conductor arrangement for the operating voltage of the line. In the case of the Project, a three-conductor bundle in a delta arrangement was selected largely for this purpose. The potential for radio and television signal interference due to corona discharge relates to the magnitude of the transmission line-induced radio frequency noise compared to the strength of the broadcast signals. Because radio frequency noise, like electric and magnetic fields, becomes significantly weaker with distance from the transmission line conductors, very few practical interference problems occur with existing transmission lines. In most cases, the strength of the radio or television broadcast signal within a broadcaster's primary coverage area is great enough to prevent interference.

If interference from transmission line corona associated with the Project does occur for an AM radio station within a station's primary coverage area where good reception existed before the Project was built, satisfactory reception can be obtained by appropriate modification of (or addition to) the receiving antenna system. The situation is unlikely, however, because AM radio frequency interference typically occurs immediately under a transmission line and dissipates rapidly with increasing distance from the line.

FM radio receivers usually do not pick up interference from transmission lines because:

- Corona-generated radio frequency noise currents decrease in magnitude with increasing frequency and are quite small in the FM broadcast band (88-108 Megahertz), and

- The interference rejection properties inherent in FM radio systems make them virtually immune to amplitude type disturbances.

The potential for television interference due to radio frequency noise caused by transmission lines is even lower now that the United States has completed the transition to digital broadcasting. Digital reception is in most cases considerably more tolerant of noise than analog broadcasts. Due to the higher frequencies of television broadcast signals (54 MHz and above) a transmission line seldom causes reception problems within a station's primary coverage area. In the rare situation where the Project may cause interference within a station's primary coverage area, the problem can usually be corrected with the addition of an outside antenna.

Shadowing and reflection effects are typically associated with large structures, such as high buildings, that may cause reception problems by disturbing broadcast signals and leading to poor radio and television reception. Although the occurrence is rare, a transmission structure or the conductor can create a "shadow" on adjoining properties that obstructs or reduces the transmitted signal. Structures may also cause a "reflection" or scattering of the signal. Reflected signals from a structure result in the original signal "breaking" into two or more signals. Multipath reflection or "scattering" interference can be caused by the combination of a signal that travels directly to the receiver and a signal reflected by the structure that travels a slightly longer distance and is received slightly later by the receiver. If one signal arrives with significant delay relative to the other, the picture quality of both analog and digital television broadcast signals may be impacted. With analog broadcasts, a second image may appear on the receiver's screen and displace the other. This type of reception interference is known as "ghosting" or "delayed image." With digital broadcasts, the picture can become pixelated or freeze and become unstable. The most significant factors affecting the potential for signal shadow and multipath reflection are structure height above the surrounding landscape and the presence of large flat metallic facades. Potential shadow and reflection effects from the Project tend to be minimized because there are spaces between the members of the steel lattice structures and because the structures will be placed up to 1,400 feet apart. Due to the spaces between the lattice elements, and the large spaces between individual structures, the Project's structures do not create one large obstacle, and broadcast signals should travel through the structures, minimizing the likelihood of shadowing and reflection effects.

A two-way mobile radio located immediately adjacent to and behind a large metallic structure, such as a steel tower, may experience interference because of signal-blocking (shadowing) effects. Movement of either mobile unit so that the metallic structure is not immediately between the two units should restore communications. This would generally require a movement of less than 50 feet by the mobile unit adjacent to a metallic tower.

Television interference is rare but may occur when a large transmission structure is aligned between the receiver and a weak distant signal, creating a shadow effect. Digital reception is somewhat less resistant to multipath reflections (i.e. reflections from structures) than analog broadcasts. In the rare situation where the Project may cause interference within a station's primary coverage area, the problem can usually be corrected with the addition of an outside antenna.

If television or radio interference is caused by or from the operation of the proposed facilities in those areas where good reception was available prior to construction of the Project, Minnesota Power will inspect and repair loose or damaged hardware in the transmission line, or take other necessary action to restore reception to the present level, including the appropriate modification of receiving antenna systems if necessary.

5.4.4. Noise

Noise is defined as unwanted sound. It may be comprised of a variety of sounds of different intensities across the entire frequency spectrum. Noise is measured in units of decibels (dB) on a logarithmic scale. Because human hearing is not equally sensitive to all frequencies of sound, certain frequencies are given more "weight." The A-weighted decibel (dBA) scale corresponds to the sensitivity range for human hearing. A noise level change of 3 dBA is barely perceptible to average human hearing. A 5 dBA change in noise level is clearly noticeable. A 10 dBA change in noise level will be perceived as doubling (or halving) the loudness of the noise. For reference, Table 5.4.4A shows noise levels associated with common, everyday sources, providing context for the transmission line and substation noise levels discussed in the section.

Table 5.4.4A: Common Noise Sources and Levels

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

Source: A Guide to Noise Controls in Minnesota, MPCA (revised, 1999), http://www.pca.state.mn.us/index.php/view-document.html?gid=5355.

In Minnesota, statistical sound levels (L Level Descriptors) are used to evaluate noise levels and identify noise impacts. The standards are expressed as a range of permissible dBA within a one hour period. L5 is defined as the noise level, in dBA, that may be exceeded 5 percent of the time, or for three minutes in an hour. L50 is the noise level, in dBA, that may be exceeded 50 percent of the time, or for 30 minutes in an hour.

Land areas, such as picnic areas, churches, or commercial spaces, are assigned an activity category based on the type of activities or use occurring in the area. Activity categories are then categorized based on their sensitivity to traffic noise. The Noise Area Classification ("NAC") is listed in the MPCA noise regulations to distinguish the categories. Residential areas, churches, and similar type land use activities are included in NAC 1; commercial-type land use activities are included in NAC 2; and industrial-type land use activities are included in NAC 3.

Table 5.4.4B identifies the established daytime and nighttime noise standards by NAC.

Table 5.4.4B: Noise Standards by Noise Area Classification (dBA)

NAC	Daytime		Nighttime	
	L50	L5	L50	L5
1	60	65	50	55
2	65	70	65	70
3	75	80	75	80

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

Noise emissions from a transmission line occur during certain weather conditions. In foggy, damp or rainy weather, transmission lines can create a crackling sound due to corona – the small amount of electricity ionizing the moist air near the conductors. During heavy rain the background noise level of the rain is usually greater than the noise from the transmission line. As a result, people do not normally hear noise from a transmission line during heavy rain. During light rain, dense fog, snow and other times when there is moisture in the air, transmission lines will produce audible noise equal to approximately household background levels. During dry weather, audible noise from transmission lines is barely perceptible.

At substations, audible noise is generated primarily by transformers. New substations and substation upgrades will be designed and constructed to comply with state noise standards established by the Minnesota Pollution Control Agency ("MPCA"). Maximum and typical levels of audible noise attributable to each of the proposed transmission facilities voltages will be calculated and field monitored as needed. Any noise monitoring will be conducted in accordance with Minnesota Rule 7030.0060.

Table 5.4.4C: Noise Calculations

Structure Type	L50 Noise (dBA) Edge of ROW	L5 Noise (dBA) Edge of ROW
500 kV Single Circuit Guyed Delta Tower	47.9	51.4
500 kV Single Circuit Self-Supporting Tower	47.2	50.7
500 kV Single Circuit Guyed-V Tower	47.2	50.7

5.4.5. Visual Impacts

The landscape in the Project area is highly variable, ranging from open tilled agricultural land to densely wooded areas with large lakes. The majority of the Project area is relatively flat, with the exception of the Iron Range where the terrain becomes moderately hilly with steeply sloped areas adjacent to active mining pits. On the western side of the Project area, the landscape is dominated by row crop agriculture with limited topographic variation, resulting in high visibility of tall structures. Many of the forested portions of the Project area also have limited topographic variation, but the height and density of the trees on the landscape will likely limit visibility of tall structures. The proposed Project is not anticipated to be visible from any areas having high visual sensitivity, such as national parks or wilderness areas. It would, however, cross state designated scenic byways.

The Project area contains existing transmission structures up to 500 kV in size, which are of similar height as the structures for the proposed Project. The highest density of existing transmission lines is in the Iron Range, due to the heavy electrical use by mining and the higher density of population centers in the area. Due to the topographic variation in this area and the higher density of population, it is likely that transmission line structures will have increased visibility on the Iron Range relative to other portions of the Project area.

The Project is prohibited from being placed in specific types of protected lands under Minn. R. 7849.5930. These lands include wilderness areas, Scientific and Natural Areas (SNAs), national parks and state parks. The Project area does not contain any wilderness areas or national parks nor is the Project area close enough to be visible from either type of these protected lands. Depending on the final route chosen, the Project may be visible from other protected lands such as SNAs and state parks, as well as from scenic byways. In wooded areas, visual impacts are expected to be minimal because of the natural screening. Visual impacts in agricultural areas may be more prominent given the lack of topography and lack of natural visual screening.

6. PROJECT NEED

6.1. Minnesota Power's Resource Needs and the Approved 250 MW Agreements

As discussed in Section 2, above, the Commission has already recognized the need for additional transmission capacity to facilitate energy trade between Manitoba and the United States in the 938 Docket. The 938 Docket completed a regulatory process of identifying Minnesota Power's resource needs and selecting the best means of meeting those needs – a process that began in Minnesota Power's 2010 resource planning docket, the 1088 Docket. Notably, in approving the 250 MW Agreements, the Commission concurred with the Department's comments stating that both Manitoba Hydro and Minnesota Power "*must* construct their own new transmission facilities (in Canada and the USA respectively) to allow MH to sell the contracted power" to the Company. Given this recognized need for new transmission facilities, the Commission required Minnesota Power to file reports on various significant milestones achieved regarding both the new hydroelectric generating stations being built in Manitoba and on the new major transmission facilities. The Project represents the Minnesota portion of these major new transmission facilities, necessary to deliver the power called for under the approved 250 MW Agreements.

Minnesota Power's need for the additional capacity and energy to be delivered by Manitoba Hydro pursuant to the 250 MW Agreement is further demonstrated by Minnesota Power's most recent Advanced Forecast Report ("AFR"), filed in July 2013 pursuant to Minnesota Rules 7610 and attached as Appendix H. Given Minnesota Power's industrial load concentration, the AFR includes multiple industrial load growth scenarios. As Minnesota Power discussed in its exemption request, the Wholesale and Industrial Customer Addition scenario provides the most relevant information for the purpose of this Application and supports Minnesota Power's need for the additional capacity and energy to be purchased from Manitoba Hydro.

Further, Minnesota Power's 2013 Integrated Resource Plan ("2013 Plan"), MPUC Docket No. E-015/RP-13-53, included the Project and the 250 MW Agreements with Manitoba Hydro in all scenarios evaluated.[19] The 2013 Plan, approved by the Commission, represented Minnesota Power's next step in its Energy***Forward*** resource strategy, designed to supply its customers with a safe, reliable, and affordable power supply while reducing coal fleet emissions, sustaining its high quality energy conservation program, adding renewables in the near term and adding natural gas in the long-term. This strategy is reshaping the company's power supply from a predominantly coal-based energy mix to a diverse supply that minimizes customer costs and retains reliability. A diverse and balanced resource mix of one-third renewable energy sources, one-third coal and one-third natural gas will provide Minnesota Power the flexibility to

[19] The 2013 Plan Initial Filing, March 1, 2013, is included at Appendix J.

address its need to meet air quality regulations in an economically and environmentally beneficial manner. It will also allow Minnesota Power to better manage risk associated with any future federal or state regulations and policies that restrict carbon emissions or penalize generators of those emissions.

That diversification is already well underway with much of the progress attributed to the successful implementation of the Company's renewable plans, including wind and wood additions plus the 250 MW Agreements and 133 MW Renewable Optimization Agreements between the Company and Manitoba Hydro. This Project represents another critical step down this path set forth in the Energy***Forward*** resource strategy. For Minnesota Power, the Project will deliver power that meets its anticipated increases in annual energy demand while increasing service reliability and providing a new high voltage transmission connection to a clean, carbon-free renewable energy resource.

Finally, the Project allows Minnesota Power and Manitoba Hydro to take advantage of a unique resource optimization opportunity. As part of an energy exchange agreement, upon completion of the Project Minnesota Power would schedule energy from their wind-generating facilities to Manitoba Hydro when wind production is high. When using that wind power, Manitoba Hydro would be able to temporarily reduce their hydropower generation by decreasing the flow of water through their hydropower plants. The water stored during that process would be used later to generate electricity to schedule to Minnesota when wind energy production is low. This arrangement optimizes the use of both wind-generated energy and hydropower.

6.2. State and Regional Resource Needs

6.2.1. Overall System Constraints

In the 938 Docket, the Commission recognized that the current transmission system cannot support the delivery of an additional 250 MW of power from Manitoba to the Minnesota Power service area. Of course, the current transmission system also cannot support the additional 133 MW Renewable Optimization Agreements, now being finalized between Minnesota Power and Manitoba Hydro. The Project alleviates these current constraints and will facilitate additional sales of hydropower to Minnesota and regional utilities. These additional sales may become increasingly important as other state and regional utilities also seek to integrate large quantities of wind power on their systems and respond to increasing pressure to avoid or mitigate carbon emissions. Manitoba Hydro has been a consistent supplier of energy into Minnesota since the first interconnection was built between Manitoba and the United States in 1970. Developing a HVTL that delivers to Minnesota Power the 383 MW contracted for in the 250 MW Agreements and 133 MW Renewable Optimization Agreements to northern Minnesota and also has the capacity to deliver additional hydropower to other utilities in the Upper Midwest would help meet these future state and regional energy needs.

The existing interface between Manitoba and the United States consists of three 230 kV lines and one 500 kV line. A special protection system currently enables the transmission grid to be operated reliably in the event of an unplanned outage of any of these tie lines. However, an unplanned outage of the existing 500 kV line is currently the largest single contingency in MISO. The Project will reduce loading on the existing tie lines and improve the performance of the transmission system during contingencies, benefitting the entire state and region.

6.2.2. Impact of Project on System Efficiency

In addition to providing valuable redundancy in the event of an unplanned outage, the Project brings substantial efficiency benefits to the state and region, as discussed in Section 2, above. The Project will reduce overall transmission system losses, as discussed in Section 4.5, above. The estimated peak loss reduction in the MISO West Planning Region with no incremental Manitoba to United States transfers is approximately 21 MW. This is 21 MW of power that would no longer be required during system peak times, when energy prices are typically the highest and more uneconomical units are required to run. Beyond system loss savings, the Project will also relieve the main constraint associated with the North Dakota – Manitoba loop flow phenomenon, which is discussed in further detail in Section 7.4.3, below. This will have the long-term impact of enabling considerable levels of simultaneous transfers of hydroelectric power from Manitoba and wind power from the Dakotas without overloading any of the Manitoba – United States tie lines. Compared to other alternatives, the Project will provide the most long-term outlet capability from Manitoba and North Dakota before requiring the development of new transmission. Simply stated, the Project is the best way to improve efficiency and reliability and maximize production and delivery of clean, carbon-free renewable energy into Minnesota and the Upper Midwest.

The Project would also enable the optimized wind-water "synergy" discussed above on a regional basis. Moreover, the Project could facilitate high simultaneous production from both resource types. This efficiency of design provides Minnesota Power and the region with the desired wind-water synergy without restricting the long-term operation of the system should high simultaneous production from wind and hydropower resources become desirable.

6.3. The Project Provides Overall Societal Benefits

In addition to meeting the energy and reliability needs of Minnesota Power, the State and the region, the Project provides additional societal benefits in the form of increased access to renewable energy, leveraging the synergies available between wind and hydropower and stimulating economic activity.

6.3.1. Increased Delivery of Reliable and Environmentally Sound Energy

Manitoba Hydro has been a consistent and reliable supplier of energy to Minnesota and the Upper Midwest for nearly 35 years, since the construction of the first tie line between Manitoba and United States. Since 2005, total sales from Manitoba Hydro into Minnesota and North Dakota has averaged over 9,000 gigawatt hours ("GWh").[20] With Manitoba Hydro's system consisting of over 95% hydroelectric power, Manitoba Hydro estimates that its sales of electricity to United States utilities translates to displacing greenhouse gas emissions amounting to nearly 200 million tons of carbon dioxide since 1970.

Moreover, Manitoba Hydro has a number of long term sales of accredited capacity, as well as energy, to customers in the MISO market. In 2014, Manitoba Hydro has 1,050 MW of capacity sales to United States utilities, including 50 MW to Minnesota Power, which are used to meet the regional resource adequacy requirements under Module E of the MISO Transmission and Energy Market Tariff ("TEMT"). MISO reviews the terms and conditions of these contracts to ensure they meet the requirements of Module E of TEMT. Sourcing capacity from hydro resources in Manitoba in this manner provides portfolio diversification of fuel supply and reduces fuel delivery risk for the purchasing utilities.

6.3.2. Wind and Hydro Synergies

As the Commission noted in the 938 Docket, the Commission-approved 250 MW Agreements between Minnesota Power and Manitoba Hydro facilitates a unique arrangement that recognizes the ability of hydroelectric power to partner with intermittent resources such as wind and thereby maximize system benefits. MISO's Manitoba Hydro Wind Synergy Study notes that "the variable and non-peak nature of wind creates integration challenges within MISO. Manitoba Hydro, with its large and flexible system, offers potential solutions for meeting these challenges."[21] Given that potential, MISO conducted the Wind Synergy Study to evaluate whether the cost of expanding the transmission capacity between Manitoba and MISO would enable greater wind participation in the MISO market. The Study confirms that significant benefits can be realized by the addition of a 500 kV line between the Dorsey station, in southern Manitoba, and the United States and the development of new hydroelectric generating stations in Manitoba. Among the benefits from this additional large tie line are production cost savings and modified production cost savings, load cost savings, reserve cost savings and wind curtailment reduction.

---

[20] Canadian National Energy Board, Electricity Exports and Imports - Monthly Statistics, available at: http://www.neb.gc.ca/clf-nsi/rnrgynfmtn/sttstc/lctrctyxprtmprt/lctrctyxprtmprt-eng.html

[21] Appendix I, p. 1.

6.3.3. Economic Impact

The Project also benefits the economy. First, Minnesota Power estimates a work force required for construction of the Project's facilities of over 200 people per year. This includes tree trimming crews, transmission line construction workers, substation upgrade construction workers, safety supervisors, environmental support, and other on- and off-site support staff. These jobs and associated construction activities will provide an influx of additional dollars into the communities during the construction phase, with construction materials purchased from local vendors where feasible.

In addition, the Project has indirect economic impacts. To gauge the overall economic impact of the Project on the northern Minnesota economy, Minnesota Power contracted for the Labovitz Study, included as Appendix L to this Application. The Labovitz Study found that the Project will generate over $850 million in economic impact in northern Minnesota for the design and construction period of 2016 through 2020. Included in this figure are local, state and federal tax benefits. The Labovitz Study, Appendix L, found that the Project will generate, from both development and construction, almost $28.9 million in State and Local taxes and just over $30.5 million Federal taxes throughout the course of the project. In addition, it is estimated that property taxes will be in the range of $40,000 - $60,000 per mile annually after the line is placed in service.

In addition, the Project will strengthen the transmission system in one of the few areas in the region poised for significant economic growth, with attendant electric load growth. The bulk of this load growth is associated with planned mining and industrial expansion on the Iron Range. Development of a second 500 kV interconnection on the Iron Range will provide another strong source of reliable power to one of the most demanding, rapidly expanding load pockets in the region.

Finally, in order to assess the economic impact of the Project on lowering costs for electric consumers in Minnesota, Minnesota Power commissioned a consultant (Ventyx) to perform a PROMOD analysis to estimate the economic impact based on three metrics:

- the change in locational marginal prices specific to Minnesota;
- the change in adjusted production costs within Minnesota and MISO region;
- the savings to Minnesota from reduced transmission losses.

The GNTL Economic Impact Study will utilize economic models developed during the analysis of the MISO Northern Area Study, discussed in Section 7.2.1, below. While not the main study objective of the Northern Area Study, the Project, along with a separate 345 kV build from Blackberry to Arrowhead, was assumed as a base case facility in many models that were reviewed by MISO stakeholders. For Minnesota Power's economic analysis, these models were modified to exclude the Blackberry – Arrowhead 345 kV project and better align with Minnesota Power's identified resource planning philosophy concerning such issues as coal retirements, coal unit conversion to natural gas, and future wind development plans. The analysis will look at model years 2022 and 2027 and also include scenarios simulating a business as usual (BAU) and High Demand in Energy ("HDE") future. These scenarios will be simulated both with and without the Project to capture economic impacts.

A sensitivity analysis looking at the additional impact assuming a carbon tax was also added to the economic analysis. The cost of coal assumptions were based on a mid-level CO2 tax meant to capture environmental and socioeconomic costs, docket Nos. E-999/CI-93-583 and E-999/CI-00-1636. The economic analysis is ongoing and is expected to be completed the end of October 2013 with the carbon sensitivity analysis completed shortly thereafter. While not a requirement for completeness under the Commission's rules, Minnesota Power will supplement this Docket as soon as the GNTL Economic Impact Study is finalized.

6.4. The Project will Comply With Relevant Policies and Regulations of Other State and Federal Agencies and Local Governments

Minnesota Power is committed to full compliance with relevant policies and regulations related to the Project. As detailed in Section 3.3, above, Minnesota Power has engaged in extensive stakeholder discussions prior to filing the Application, including discussions with tribal, federal, state and local representatives and authorities. As part of this process, Minnesota Power has participated in several multi-agency meetings and has appreciated the efforts of federal and state agencies to coordinate activities regarding this project. Table 3.5 provides a listing of the permits required for the Project and Minnesota Power anticipates receiving all such permits prior to construction.

6.5. Delay or Denial Would Adversely Impact Minnesota Power, the State and the Region

Denial of a certificate of need for the Project would adversely impact Minnesota Power, its customers, the state and the region. For Minnesota Power, the immediate and direct impact of denial would be the inability to take delivery of needed power from Manitoba Hydro under the Commission-approved 250 MW Agreements. In approving the 250 MW Agreements, the Commission has already determined that the hydropower resources proposed in the PPA represent the most appropriate resources to meet Minnesota Power's resource needs over the period 2020 through 2035 and that the 250 MW Agreements are in the public interest. Thus, denial of a certificate of need for the Project, and the resulting inability for Minnesota Power to take delivery of the contracted hydropower, would leave Minnesota Power with significant unmet needs and would compel addition of less appropriate resources to fill those needs. Loss of the contracted-for hydropower would come with an economic cost, as well as a cost in diversification of generation resources.

Moreover, the Company and its customers would lose the ability to receive the benefits of the additional 133 MW Renewable Optimization Agreements, meaning again the Minnesota Power would have to look to other, less optimal resources to fill its needs.

Importantly, by losing the ability to deliver the benefits of the 250 MW Agreements and 133 MW Renewable Optimization Agreements, and the associated renewable energy storage provisions, Minnesota Power and its customers would lose the advantages brought about by the synergies possible through the coordination of wind and hydropower contemplated by Minnesota Power and Manitoba Hydro, as identified in the Manitoba Hydro Wind Synergy Study.

Finally, denial of a certificate of need would mean the loss of the regional benefits that can be brought about by the Project, including the additional ability to meet regional needs with hydropower, building a more reliable system by reinforcing the connections between Minnesota and Manitoba, thereby addressing the single largest contingency in MISO's northern region, and increasing the transfer capability between Manitoba and the United States.

6.6. Minnesota Right of First Refusal

In 2012, in response to FERC Order No. 1000 that eliminated federal rights of first refusal ("ROFR") in federal tariffs, Minnesota enacted a state ROFR for new transmission lines that connect to the facilities of incumbent electric transmission owners.[22] The state ROFR is triggered when a transmission line has been approved for construction by a federally registered planning authority transmission plan and connects to facilities owned by that incumbent electric transmission owner.

For purposes of this Project, the federal planning entity is MISO and the facility that will be connected to is Minnesota Power's Blackberry Substation. While the Project has been submitted to the MISO MTEP process and is currently in Appendix B in that process, until a Facilities Construction Agreement ("FCA") is executed and submitted to FERC for approval, the Project will not meet the statutory criteria of being approved by MISO. Minnesota Power and Manitoba Hydro are working closely with MISO to finalize a FCA and will provide updates in this Docket regarding the status of the FCA and MISO approval.

While State ROFR rights are applicable to this Project, because the MISO process is still ongoing, the Commission procedure set forth under Minn. Stat. § 216B.246, subd. 3 does not yet apply. The Commission procedure requires that the incumbent electric

[22] *See* Minn. Stat. § 216B.246.

transmission owner, here Minnesota Power, provide the Commission notice within 90 days of MISO approval, regarding its intent to construct, own, and maintain the electric transmission line and file a Certificate of Need application within 18 months of the notice. By filing this Application, Minnesota Power provides its intent to build the Project and connect to its existing Blackberry Substation.

7. ALTERNATIVES ANALYSIS

7.1. Alternatives Analyzed and Overall Approach

In any Certificate of Need proceeding on a proposed transmission line project, an applicant is required to consider various alternatives to the proposed project. Minnesota Statutes provide that in assessing need, the Commission will evaluate "possible alternatives for satisfying the energy demand or transmission needs." The Commission has also provided in its rules that an applicant for a Certificate of Need must discuss in the application the possibility of a number of alternatives. Minnesota Rules 7849.0260 states:

> Each application for a proposed large high voltage transmission line ("LHVTL") must include:
>
> B. a discussion of the availability of alternatives to the facility, including but not limited to:
>
> (1) new generation of various technologies, sizes, and fuel types;
>
> (2) upgrading of existing transmission lines or existing generating facilities;
>
> (3) transmission lines with different design voltages or with different numbers, sizes, and types of conductors;
>
> (4) transmission lines with different terminals or substations;
>
> (5) double circuiting of existing transmission lines;
>
> (6) if the proposed facility is for DC (AC) transmission, an AC (DC) transmission line;
>
> (7) if the proposed facility is for overhead (underground) transmission, an underground (overhead) transmission line; and
>
> (8) any reasonable combinations of the alternatives listed in subitems (1) to (7).

Minn. R. 7849.0340 also requires an applicant to consider the option of not building the proposed facility.

This section discusses the various alternatives to the proposed Project that Minnesota Power considered. These alternatives include: 1) generation alternatives; 2) various transmission solutions, including upgrading other existing facilities, different voltage levels and different endpoints; and 3) a no-build alternative. As discussed below, none of these alternatives is more reasonable and prudent than the Project.

7.2. MISO Studies Considered In Analysis

Minnesota Power's consideration and analysis of alternatives has been aided and informed by MISO studies, including the Northern Area Study, the Manitoba Wind Synergy Study and the Manitoba Hydro-United States Transmission Service Request ("TSR") Analysis.

7.2.1. MISO Northern Area Study

The MISO Northern Area Study was complementary and closely coordinated with other studies, including the Manitoba Hydro Wind Synergy Study and the Manitoba Hydro TSR Sensitivity Studies. The Northern Area Study was developed as an exploratory study to understand how the development of new potential Manitoba – MISO tie-lines, changing mining/industrial load levels, and the retirement of generating units drive transmission investment in MISO's footprint. The Northern Area Study originated because of multiple transmission proposals and reliability issues located in MISO's northern footprint. Developed through a technical review group (TRG), the objective of the Northern Area Study was to:

- Identify the economic opportunity for transmission development in the area
- Evaluate the reliability and economic effects of drivers on a regional, rather than local, perspective
- Develop indicative transmission proposals to address study results with a regional perspective
- Identify the most valuable proposal(s) and screen for robustness

The Northern Area Study was a collaborative effort between stakeholders and MISO staff. Meetings were open to all stakeholders and interested parties - study participants included state regulatory agencies, transmission owners, market participants, environmental groups, and industry experts. A stakeholder TRG was involved in all discussions and decisions. The study analyzed 38 different TRG developed options to mitigate three congestion interfaces. These congested interfaces included Dakotas/Minnesota, Minnesota/Wisconsin, and Wisconsin/Upper Peninsula of Michigan. It was found that the Northern Area Study individual transmission options could realize up to $84.4 M in adjusted production cost savings with benefit to cost ratios ranging up to 14.7:1. The most cost-effective options mitigate future congestion from wind on the Dakotas/Minnesota border and were sub-345 kV.

The potential for industrial load increases and decreases was the first scenario driver for the Northern Area Study. The driver for studying industrial load levels in Northern Area Study scenarios originated with a request to evaluate transmission potential through the Upper Peninsula of Michigan and was later expanded to the larger Northern Area Study region, including 600 MW of additions in northern Minnesota.

The second driver was unit retirements, specifically the potential retirement of the Presque Isle Power Plant in Marquette, Michigan. On November 27, 2012 an agreement was announced to keep the Presque Isle Power Plant online. All Presque Isle retirement scenarios were subsequently removed from the Northern Area Study. This resulted in decreased production cost saving potential for new conceptual transmission lines supporting the Upper Peninsula (UP).

The third driver was a potential for increased generation and imports from Manitoba Hydro, along with the transmission required to facilitate these imports. Manitoba Hydro has development plans for adding two additional hydro units, Keeyask (695 MW) and Conawapa (1,485 MW). Together, the units would increase import potential into MISO by approximately 1,100 MW, while the remaining capacity would serve Manitoba Hydro load. To deliver 1,100 MW of imports from Manitoba Hydro to the MISO footprint three different generation and tie-line configurations were proposed for inclusion as base case assumptions in the Northern Area Study. Those three configurations are as follows:

- Conawapa and Keeyask In-Service; New Manitoba – Duluth 500 kV Tie-Line;
- Conawapa and Keeyask In-Service; New Manitoba – Fargo Area 500 kV Tie-Line;
- Conawapa and Keeyask In-Service; New Manitoba – "T" 500 kV Tie-Line.[23]

The Northern Area Study provides no indication or comparison between Manitoba to MISO tie-line options. Tie-lines and new hydro generation were inputs to the Northern Area Study to determine economic development opportunities after the tie-lines and generating units are built and in-service – essentially answering what (if any) build-out is required for MISO's entire northern footprint to realize the benefits of new Manitoba imports.

The study evaluated many different transmission options in North Dakota, Minnesota, Wisconsin, and Michigan and found that large-scale regional transmission expansion in

[23] While showing increased system benefits but also higher total projects cost it was decided by the study participants at the November 2, 2012 TRG meeting the "T" option should be eliminated from the evaluation to reduce scenario simulations.

MISO's northern footprint is not cost-effective based on production cost savings, under current business as usual conditions. Economic benefits for MISO from a new potential Manitoba Hydro to MISO tie-line could be realized with minimal incremental transmission investment. Other than a few local area congestion issues, the economic potential for the Northern Area Study footprint is relatively little; this is a result of the MISO Multi-Value Project ("MVP") Portfolio being assumed in-service, low natural gas prices, and relatively flat demand and energy growth rates. Given the hypothetical nature of the study drivers, transmission solutions stemming from the Northern Area Study analysis were not intended to be recommended for MTEP Appendix A or B consideration. Rather, the Northern Area Study's results and findings will determine and feed future studies.

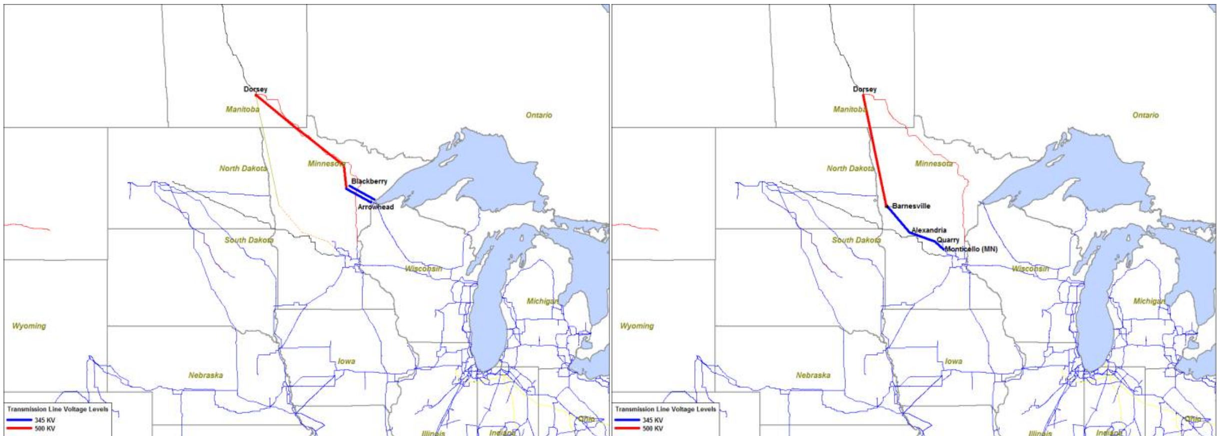
The draft study report was published in April 2013 with the final report completed on June 2013. The final report for the Northern Area Study is attached as Appendix M.

7.2.2. MISO Manitoba Hydro Wind Synergy Study

The variable and non-peak nature of wind creates integration challenges within MISO. Manitoba Hydro, with its large and flexible system, offers potential solutions for meeting these challenges. At the prompting of Manitoba Hydro and the potential customers of output from their new hydroelectric dams, MISO conducted the Manitoba Hydro Wind Synergy Study to evaluate whether the cost of expanding the transmission capacity between Manitoba and MISO would enable greater wind participation in the MISO market. MISO currently has 12 gigawatts ("GW") of wind online and 15 GW of active wind projects in the queue. Manitoba Hydro is looking to expand its hydro system by 2,230 MW over the next 15 years. Manitoba Hydro's current firm export capacity to MISO is limited to 1,850 MW which is insufficient to meet the needs of future wind generation in MISO for synergy with hydropower. Thus, this study looked at expanding transmission capacity between MISO and Manitoba Hydro to facilitate an increase in the realization of these benefits.

MISO completed its first comprehensive study that looks at the synergy between hydropower and wind power in 2013. The Manitoba Hydro Wind Synergy Study, Appendix I, found significant benefits can be realized from the addition of either an eastern 500 kV line between Winnipeg, Manitoba, and the Iron Range in northeastern Minnesota, or a western 500 kV line between Winnipeg, Manitoba, and Barnesville, Minnesota, shown below in Figure 7.2.2.

FIGURE 7.2.2 - MISO Manitoba Hydro Wind Synergy Study – Study Options



East Option: Dorsey to Blackberry	West Option: Dorsey to Fargo/Moorhead Area
- 500 kV line from Winnipeg to Grand Rapids - 345 kV double circuit line from Grand Rapids to Duluth	- 500 kV line from Winnipeg to Fargo/Moorhead Area - 345 kV line from Fargo/Moorhead to Monticello

The Manitoba Hydro Wind Synergy Study set out to evaluate the benefits and costs of expanding the interface between Manitoba Hydro and MISO. The study looked at adding an additional hydro generator in Manitoba Hydro along with the addition of one of three potential new tie lines. The combined benefits were examined including production cost savings, modified production cost savings, load cost savings, reserve cost savings, thermal generator ramping changes and wind curtailment changes. Given the wide variety of benefit metrics along with the exploratory nature of the study, the specific allocation of benefits was not possible. This study simply showed that the total benefits in the MISO area are greater than the costs to build either line.

The benefit metrics used in the Manitoba Hydro Wind Synergy Study are indicative of savings MISO may experience if either of the transmission plans were constructed, but they cannot be used to justify cost sharing of either project under the current MISO tariff. MISO conducted a hypothetical Market Efficiency Project ("MEP") eligibility test and found that MISO would receive no Adjusted Production Cost benefit from the construction of either line under the current MISO tariff and using the current MTEP12 models. Looking at these projects from a market efficiency perspective does not capture the purpose of the transmission plans, which are designed specifically to facilitate increased transfer capability between Manitoba and the United States.

Wind synergy benefits from the expanded use of hydro resources in Manitoba Hydro are demonstrated in three ways: by wind curtailment reduction in MISO; by an inverse correlation between imports from Manitoba Hydro and MISO wind generation; and by a better utilization of both wind and hydro resources. Wind curtailment in the northern MISO region was reduced by 50 to 100 GWh, depending on the plan studied and the scenario examined during the 2027 planning year. The interface between Manitoba Hydro and wind generation in northern MISO showed an inverse correlation between the two demonstrating the strong response of the hydro generators to fluctuations in MISO wind. The wind synergy between Manitoba Hydro and MISO wind resources appears to be economically beneficial for both MISO and Manitoba Hydro.

Based on the analyses from the Manitoba Hydro Wind Synergy Study, MISO recommended both transmission projects for inclusion in MTEP13 Appendix B. The final report was published in September 2013 and is attached as Appendix I.

7.2.3. MISO MH-US Transmission Service Request Study

MISO continues to process generation interconnection requests and Transmission Service Requests ("TSRs") on the transmission system that they operate. One group of these TSRs involves an increase in the ability to transfer power from Manitoba into the United States. The original Manitoba Hydro TSRs requested delivery totaling 1,100 MW from Manitoba Hydro to four TSR customers in the United States (north to south), and 1,100 MW from utilities in the United States to Manitoba Hydro (south to north).

An initial System Impact Study ("SIS") was completed in July 2009 for Firm Transmission Service between Manitoba Hydro and the TSR customers. The initial study considered several 500 kV transmission options for increasing the capability of the Manitoba – United States interface by 1100 MW flowing north or south. The study was conducted by Siemens PTI and an ad hoc study group consisting of Manitoba Hydro, MISO, and several utilities in the Upper Midwest. The two main transmission options considered in the SIS generally extended from the Winnipeg area into the United States via either northeastern Minnesota or the Red River Valley.[24] A follow-up SIS completed in April 2010 evaluated the impact of a new 500 kV interconnection from the Winnipeg area to the planned CapX2020 Bison Substation near Fargo, North Dakota.[25]

Recently, MISO has conducted a series of sensitivities on the original option to evaluate alternative transmission scenarios for achieving 250 MW, 750 MW, or 1100 MW of increased transfer capability from Manitoba to the United States. The MISO TSR Sensitivity Studies have included a "Western Plan" extending new 500 kV transmission to the Barnesville area in western Minnesota, an "Eastern Plan" extending new 500 kV transmission to the Iron Range in northeastern Minnesota, and a "230 kV Option" extending new 230 kV transmission to the Iron Range. While the two 500 kV options could facilitate increased transfers of 750 MW, 1,100 MW or more, the 230 kV Option would facilitate only Minnesota Power's 250 MW Agreements with Manitoba Hydro. The MISO TSR Sensitivity Studies have demonstrated that the alternative transmission

[24] MHEB Group TSR System Impact Study Executive Summary, July 17, 2009.

[25] MHEB Group TSR System Impact Study Transmission Options W.1 and W.2, April 19, 2010.

options at their associated transfer levels do not result in negative impacts to the bulk electric system. While MISO has not yet issued a final report for this series of studies, draft reports for the Eastern Plan and the Western Plan sensitivities are included in Appendix Q. The final reports will be filed in this docket when MISO makes them available

In order to facilitate delivery of power under Minnesota Power's 250 MW Agreements, which requires new transmission to be in service by June 1, 2020, Minnesota Power and Manitoba Hydro have elected to begin moving forward with an Eastern 500 kV project. This project involves extension of a new 500 kV line from the Dorsey Substation in Manitoba to the Blackberry Substation on the Iron Range. The new 500 kV tie line will facilitate increased transfers of approximately 750 MW, including Minnesota Power's 250 MW Agreements and 133 MW Renewable Optimization Agreements and also provide additional capability for Manitoba Hydro to deliver power to the remaining TSR customers or others. A future 345 kV build from Blackberry to the Arrowhead Substation near Duluth, MN would facilitate a further increase in total transfer capability from Manitoba to the United States to at least the 1100 MW originally required by the TSRs when the additional capability is requested and needed.

7.3. Generation Alternatives

7.3.1. Role of Hydro in State and Region

The Project makes possible the delivery of the 250 MW of hydroelectric power from Manitoba Hydro to Minnesota Power, approved by the Commission in the 938 Docket. This new substantial purchase, in addition to the 133 MW Renewable Optimization Agreements currently being finalized by the parties, represents the latest example of a long and mutually beneficial energy trading relationship between Minnesota utilities and Manitoba Hydro. Manitoba Hydro, Minnesota and regional utilities have enjoyed a decades-long trading relationship, as evidenced in part by several Commission-approved PPAs between Manitoba Hydro and utilities such as Minnesota Power. Indeed, for the past several years Manitoba Hydro has supplied approximately ten per cent of the electrical needs of Minnesota customers. Since 1970, Manitoba Hydro has exported 161,791 GWh of hydro-generated electricity to United States utilities, which Manitoba Hydro estimates translates to displacing greenhouse gas emissions amounting to nearly 200 million tons of carbon dioxide.

Going forward, Manitoba Hydro is positioned to continue supplying the needs of Minnesota and regional customers with reliable and environmentally sound hydropower, in a manner consistent with Minnesota state energy policy. For example, as Manitoba Hydro stated in its recent NFAT filing:

> Manitoba Hydro is committed to protecting the environment, contributing to the global reduction of greenhouse gas ("GHG") emissions and

> maintains a diverse workforce including significant Aboriginal representation. Manitoba Hydro recognizes the need for sustainability in all aspects of its operations. Economic, environmental and societal decision criteria are applied in the assessment of major projects and plans, including public and stakeholder consultation.

In the NFAT filing, Manitoba Hydro is seeking government approval for its Preferred Development Plan, which includes the construction of both the 695 MW Keeyask generating station (which will be needed in the supply of power for the approved 250 MW Agreements) and the construction of a major new tie line to the United States (the Manitoba facilities which will connect to the Project at the Canada-US border). Manitoba Hydro also discusses the Conawapa Generating Station, a proposed 1,485 MW facility, with an earliest in service date of 2026.

Manitoba Hydro states that the Keeyask Project will take seven years to construct, with an in service date of 2019-20. The Keeyask Project will be owned by a partnership between Manitoba Hydro and four Keeyask Cree Nations ("KCNs"): Tataskweyak Cree Nation ("TCN"), War Lake First Nation ("WLFN"), York Factory First Nation ("YFFN") and Fox Lake Cree Nation ("FLCN"). A Joint Keeyask Development Agreement addresses the KCNs' income-sharing, training, employment, business opportunities, and involvement in environmental and regulatory affairs. Manitoba Hydro has already worked with and will continue to work with the KCNs partners to mitigate and reduce any adverse effects of the Keeyask Project and make environmental and socio-economic impacts as positive as possible.

The Conawapa Project will take approximately 10 years to construct. The ownership structure for the Conawapa Project has not been finalized, but Manitoba Hydro has stated its commitment to providing the First Nations in the vicinity of the project with long-term sustainable benefits, early involvement and extensive consultations, and opportunities to participate in the environmental governance of the project. As with the Keeyask Project, Manitoba Hydro's plans for the Conawapa Project will include positive measures to address environmental and socio-economic effects. Studies in the past decade have involved five local Cree Nations in the vicinity of the project: FLCN, YFFN, TCN, WLFN and Shamattawa First Nation.

The Manitoba portion of the Manitoba - Minnesota Transmission Project will consist of a 500 kV line in southeastern Manitoba, connecting at the border with the Project. As Manitoba Hydro notes in its NFAT filing, this new tie line would "enable power to be exported to the [United States] based on current sales agreements, improve reliability and import capacity in emergency and drought situations, and increase [Manitoba Hydro's] access to markets in the [United States]" going forward, including enabling extensions of large contracts currently in place with United States utilities.[26] As discussed above,

[26] *See* Appendix E, pp. 6, 33.

Manitoba Hydro will be responsible for a portion of the capital and ongoing operating costs associated with the Project (United States portion of the facilities). For its Preferred Development Plan, as presented in the NFAT filing, Manitoba Hydro has assumed that it could be responsible for up to two-thirds of the capital and ongoing operating costs associated with the Project.

Through this Preferred Development Plan, Manitoba Hydro is uniquely positioned to continue playing a critical role in supplying Minnesota Power, its customers, and others in the state and region with a reliable, uniquely flexible and environmentally sound, non-emitting electric energy resource providing that sufficient transmission facilities are built to enable those energy sales and optimize the wind-hydro synergies discussed in this Application. The Project provides those necessary transmission facilities. In contrast, pursuing a smaller transmission line would not enable these additional sales and resource optimization opportunities, negatively impacting Minnesota and regional utilities whose current PPAs with Manitoba Hydro will expire over the next decade.

7.3.2. Benefits of Diversified Portfolio of Supply for Minnesota Power's Customers

As discussed above, Minnesota Power's 2013 Plan included the Project and the 250 MW Agreements with Manitoba Hydro in all scenarios evaluated. The 2013 Plan, approved by the Commission, represented Minnesota Power's next step in its Energy***Forward*** resource strategy, designed to supply its customers with a safe, reliable, and affordable power supply while diversifying its supply resources. This strategy is reshaping the company's power supply from a predominantly coal-based energy mix to a balanced resource mix of one-third renewable energy sources, one-third coal and one-third natural gas. This diversification will provide Minnesota Power the flexibility to address its need to meet air quality regulations in an economically and environmentally beneficial manner and also allows the Company to better manage risk associated with any future federal or state regulations and policies that restrict carbon emissions or penalize generators of those emissions. The Project makes possible the delivery of this more diverse resource mix, as opposed to pursuing fossil fuel-fired generation alternatives to meet Minnesota Power's identified capacity and energy needs.

7.3.3. Commission-approved 250 MW Agreements

Through Minnesota Power's resource plan filings and the 938 Docket, the Company, Commission and interested parties have already examined generation alternatives for meeting the capacity and energy needs met by the Project and the 250 MW Agreements. For example, in the 938 Docket, the Department and Commission specifically examined whether "the resources proposed in the PPA represent the most appropriate resources to meet [Minnesota Power's] resource needs over the period 2020 through 2035."[27] The

[27] Appendix C, Department Comments, p. 13.

Department and Commission both answered that question in the affirmative. No other generation alternatives were identified, in either the resource planning dockets or the 938 Docket, that can meet the Company's capacity and energy needs more reasonably and prudently than by way of the Project and the 250 MW Agreements.

7.3.4. Distributed Generation

Minnesota Power has examined distributed generation opportunities, including opportunities with its large industrial customers in its Resource Plan filings. As the Company discussed in its 2013 Plan, it is working to develop a fair, equitable and customer-facing distributed generation program that best leverages unique customer and regional attributes to deliver valued and cost effective energy solutions for customers. However, while distributed generation resources may play a role in the Company's overall resource strategy going forward, they cannot displace the need for the Project and the substantial energy and capacity deliveries it makes available to Minnesota Power's customers.

7.3.5. Community-Based Energy Development (C-BED) Efforts

Minn. Stat. § 216B.1612, subd. 5(c) states that "the Commission shall consider the efforts and activities of a utility to purchase energy from C-BED projects when evaluating its good faith effort towards meeting the renewable energy objective under section 216B.1691." In prior transmission Certificate of Need dockets (e.g., ET-2, E-015/CN-10-973) the Department has requested applicants to provide additional information on C-BED projects. Minnesota Power has one C-BED Project under contract. Wing River is an operating 2.5 MW wind project comprised of one 2.5 MW Nordex turbine located near Hewitt, Minnesota. This project began operation in July 2007 achieving two firsts: 1) the first C-BED project in Minnesota to begin operation; and 2) the first 2.5 MW Nordex turbine installation in the United States. Minnesota Power has a 20-year power purchase agreement with Wing River LLC for all energy, capacity and renewable attributes from the Wing River C-BED Wind Project (Docket No. E-015/M-07-537).

Since enactment of the first C-BED legislation, Minnesota Power has continually reviewed C-BED project proposals. Most recently, in early 2013 Minnesota Power issued an RFP for up to 210 MW of wind. Minnesota Power specifically spelled out C-BED projects in the RFP and categorized them separately from the non-CBED wind proposals. As provided in Attachment A to Minnesota Power's Petition in Docket No. E-015/M-13-907, the C-BED proposals in the RFP were not competitive with Minnesota Power's self-build resource option or other non-CBED proposals.

After several years of Minnesota Power exploring C-BED wind projects, obstacles have continued to arise, particularly with regard to developers' challenges obtaining financing and wind turbines. These obstacles have caused significant delays in contract and project implementation. Additionally, not all areas in the state have equal potential for the development of economical C-BED projects as a result of the wide variation in the quality of wind and other renewable resources between each region. In addition, Minnesota Power has participated the C-BED Advisory Task Force and other policy and legislative arenas to assist with the development of solutions.

7.4. Transmission System Alternatives

7.4.1. Upgrades of Existing Transmission or Generation

Minnesota Power considered the possibility of upgrading existing facilities to accommodate increased hydropower transfers from Manitoba to the United States. The existing interface between Manitoba and the United States consists of three 230 kV lines and one 500 kV line. The three 230 kV lines from Manitoba to the United States are G82R from Glenboro to Rugby (North Dakota), L20D from Letellier to Drayton (North Dakota), and R50M from Richer to Moranville (Minnesota). The Dorsey – Forbes 500 kV line, known as D602F, originates at the Dorsey Substation near Winnipeg, Manitoba and connects to the Forbes Substation on Minnesota's Iron Range and then continues on to the Chisago Substation near the Twin Cities. Current total firm transfer capability on the Manitoba – United States interface is 2,175 MW southward and 700 MW northward.[28]

The Riel Station Reliability Project, which will sectionalize the Dorsey – Forbes 500 kV line, is scheduled to be in service in late 2014. Riel Substation is also the southern terminus of Manitoba Hydro's Bipole III Project, which consists of development of a third HVDC bipole from Northern Manitoba, where the majority of Manitoba Hydro's generation is located, to the Winnipeg area. Bipole III is expected to be in service in 2017.[29] Both of these projects are intended to improve the reliability of the Manitoba Hydro transmission system, and neither will change the total transfer capability between Manitoba and the United States.

Increased transfer levels from Manitoba to the United States with no new transmission tie lines across the interface would require additional capacity on some or all of the existing tie lines. Since D602F is the largest, lowest impedance line on the interface, the majority of incremental transfers from Manitoba to the United States will flow on this line, requiring increased capacity on the line. Currently, the flow limit on D602F is based on the 2,000 amp (1732 MVA) rating of the Roseau series capacitors and line terminal equipment. While it is technically feasible to increase the rating of D602F from 2,000 amps to 2,500 amps (2165 MVA) by upgrading the Roseau series capacitors, this upgrade would be highly complex and raise a number of potential issues relating to the operation

[28] Manitoba Hydro Preliminary Group Facility Study Report for MHEM, October 2, 2013, p. 14.
[29] Manitoba Hydro Preliminary Group Facility Study Report for MHEM, October 2, 2013, p. 14.

of the line and terminal equipment as well as the reliability of the regional transmission system. Many of the specific concerns outlined below were set forth in a July 10, 2013 "White Paper" written by Manitoba Hydro titled "Summary of Potential Issues with Increasing the Rating of D602F (M602F) from 2000 Amp to 2500 Amp" ("White Paper on Series Capacitor Upgrade Issues") and all result from the electrical inefficiencies of increasing utilization of D602F beyond its existing capacity.

Historically, D602F has only had electromagnetic transient studies completed at the 2000 amp operating level. At 2500 amps, the circuit breaker transient recovery voltage and arrester energy capability would need to be confirmed. Due to higher transient recovery voltages and increased arrester energy, equipment may need to be replaced at the Forbes and Chisago Substations.[30]

Increasing the power flow on D602F would also increase the amount of reactive power consumed by the line, while an in-place series capacitor upgrade may actually result in decreased reactive power supply from the Roseau series capacitors. A detailed transient stability study would be needed to determine the steady-state and dynamic reactive power requirements of the upgraded line. Costly upgrades of the Forbes Static VAR System (SVS) would likely be required to provide additional reactive power support for the line at its increased capacity. System transient stability issues may further increase the scope of work required at Forbes if a second Static VAR Compensator (SVC) is required to provide increased dynamic range.[31]

When any of the four Manitoba – United States tie lines trips, the existing Manitoba Hydro HVDC Reduction Scheme Special Protection System (SPS) initiates a power order reduction on the high voltage direct current (HVDC) lines connecting Winnipeg to hydroelectric generation in Northern Manitoba. This HVDC power order reduction is equal to 100 percent of the flow on the line or lines that are being tripped. If a 100 percent HVDC reduction level is maintained in the SPS, the flow limit on D602F could not be increased beyond 1732 MW, even if all the limiting equipment was upgraded. This is because MISO will not allow an increase in the amount of HVDC or generation runback on an existing SPS beyond its current maximum level. Simply put, for an existing SPS, transmission or generation additions cannot make the worst runback scenario (in terms of generation loss) worse. This requirement would limit the maximum HVDC reduction and potentially the rating of D602F to 1732 MW. It would be possible to modify the SPS to limit HVDC reduction to 1732 MW, allowing flow on D602F to be increased to 2165 MW. However, the impact of this SPS modification on system transient stability, dynamic reactive power requirements, and the underlying transmission

[30] White Paper on Series Capacitor Upgrade Issues.
[31] White Paper on Series Capacitor Upgrade Issues.

system would almost certainly increase the cost and complexity of the Project as well as the overall risk to the reliability of the system.[32]

Finally, loss of D602F and the associated HVDC reduction is currently the largest single contingency in MISO. In the current system, the maximum reduction in Manitoba – United States transfers is 1500 MW. This is calculated as the difference between the system intact transfer limit of the interface (2175 MW) and steady-state transfer limit of the interface after loss of D602F (675 MW), which is often referred to as the prior outage limit. Increasing the rating of D602F in order to increase the total system intact transfer limit on the Manitoba – United States interface would therefore require a corresponding increase in the prior outage transfer limit of the interface for loss of D602F in order to avoid increasing the size of the largest single contingency in the MISO footprint. Depending on the level of increased firm capability required, it may not be possible to increase the prior outage transfer limit without building a new Manitoba – United States tie line.[33]

Aside from the reasons given above, Minnesota Power believes that upgrading existing facilities is not a feasible long-term solution given the likelihood of significant increases in hydroelectric power imports from Manitoba including and exceeding Minnesota Power's power purchase and Renewable Optimization Agreements representing 383 MW. Appropriate long-term capacity for the interface between Manitoba and the United States can be achieved more efficiently, economically, and reliably with a single new transmission line build large enough to facilitate Minnesota Power's 383 MW and additional transfer capability up to 750 MW to meet future needs in the region.

7.4.2. Alternative Voltages

Minnesota Power considered the possibility of developing a transmission line with a different design voltage to accommodate increased hydropower transfers between Manitoba and the United States. Lower voltages considered include 230 kV and 345 kV, while one design voltage higher than 500 kV (765 kV) was also considered.

7.4.2.1. 230 kV Alternative

One transmission project considered for delivery of Minnesota Power's 250 MW agreements with Manitoba Hydro was a new Winnipeg – Iron Range 230 kV line. Minnesota Power and Manitoba Hydro do not believe that such a project would meet the long-term needs of the region and would not prove to be cost-effective for customers or environmentally preferable over the long-term.

[32] Id.
[33] Id.

It is anticipated that the demand for power in certain areas of the Upper Midwest will increase over the next decade, while environmental restrictions and low priced natural gas will continue to drive small, less efficient coal units to retire. Given the favorable characteristics of hydropower resources and risks associated with carbon-emitting fuel sources, Manitoba Hydro has had several potential customers request transmission service for delivery of energy and capacity from Manitoba to the United States in the recent past. This interest in Canadian hydropower is expected to continue as utilities like Minnesota Power seek to decrease their reliance on fossil-based energy and increase their use of low- or no-emission renewable energy sources. As such, developing a transmission solution that delivers substantial hydropower to northern Minnesota, and that also has sufficient capacity to deliver additional hydropower to other utilities in the Upper Midwest will help meet the future energy needs of the region. A smaller 230 kV line cannot bring those same advantages. Furthermore, while large hydropower transfers like this do not yet meet the renewable energy requirements for utilities in the State of Minnesota, such a hydropower transfer may support compliance with renewable energy requirements for utilities in Wisconsin and other states. Finally, as evidenced by the MISO Wind Synergy Study, these large hydropower transfers facilitate overall resource optimization by taking advantage of the "energy storage" capabilities of hydropower resources.

The financing and ownership of the Project also impacts the consideration of a 230 kV alternative. As Minnesota Power and Manitoba Hydro have structured the Project, Minnesota Power ratepayers will gain the economy of scale capital cost reduction advantages of a 500 kV project as compared to the 230 kV project, as discussed in Sections 3.1 and 4.3.5, above.

For all these reasons, Minnesota Power and Manitoba Hydro believe that a new 230 kV transmission line would not be reasonable and would not be a feasible or optimal long-term solution for an interface poised to see significant growth over the next 15-20 years. Installing the Project at 500 kV is needed to facilitate the Minnesota Power-Manitoba Hydro 250 MW Agreements and the 133 MW Renewable Optimization Agreements. It will reduce the overall human and environmental impacts of required transmission expansions by optimizing the long-term use of the proposed transmission line corridor. In other words, building the new tie line large enough the first time should limit proliferation of new transmission line corridors in the future.

7.4.2.2. 345 kV Alternative

Minnesota Power considered a 345 kV alternative. First, a single 345 kV line would not be capable of the same capacity as a single 500 kV line. An equivalent project to a single 500 kV line would be a double circuit 345 kV line from Winnipeg to the Iron Range, which would be similar in construction cost or more expensive than a 500 kV line. In addition, a 500 kV line is better suited to move power over the long distance from Winnipeg to the Iron Range because it has a higher voltage and therefore higher surge impedance loading. Finally, there is no existing 345 kV equipment in the Winnipeg area where the line originates. If a double circuit 345 kV line was built instead of the proposed 500 kV line, expensive new substation equipment would be required at the Canadian endpoint to step down the voltage from 500 kV to 345 kV. Therefore, the most practical and cost-effective solution is to build the line from Winnipeg to the Iron Range as a single circuit 500 kV line.

7.4.2.3. 765 kV Alternative

Minnesota Power considered a 765 kV alternative. Since there is currently no 765 kV transmission in MISO north of Illinois, expensive transformation would be required at each substation to interconnect with existing 500 kV and/or 230 kV systems in Manitoba and Minnesota. Combined with the increased construction costs of a higher voltage line, the overall cost increase and operational complexity would not be worth the additional capacity gained by a 765 kV build, compared to a 500 kV build. Minnesota Power and Manitoba Hydro believe that the capacity and expandability available with a 500 kV line are adequate for the long-term needs of the region.

7.4.3. Alternative Terminals or Substations

Minnesota Power considered several alternative endpoints for a new 500 kV transmission line to accommodate increased hydropower transfers from Manitoba to the United States. On a regional basis, the primary alternative endpoint considered was in the Fargo-Moorhead area. On a local basis, two alternative Iron Range endpoints were considered. Full consideration of these alternative endpoints demonstrates that none of them provides a preferred solution when compared to the Project.

7.4.3.1. Fargo Area (Barnesville) Study Concept

Minnesota Power, MISO, Manitoba Hydro, and other utilities have all given substantial consideration to a conceptual 500 kV transmission line project from Manitoba to the Fargo area ("Fargo Area Study Concept" or "Concept"). In many study scenarios, this Fargo Area Study Concept exhibits similar performance and benefits when compared with the Project. However, when some of the most stressed study scenarios are considered, it can be demonstrated that the Concept has serious performance flaws compared to the Project. This is fundamentally because the Fargo Area Study Concept would introduce a new low-impedance path between North Dakota and Manitoba, dramatically aggravating the well-documented North Dakota - Manitoba loop flow phenomenon. The resulting inefficiencies in the regional transmission system would constrain generation outlet capability for North Dakota, Manitoba, or both, potentially requiring transmission system upgrades that would not otherwise be required for the Project. Having thoroughly evaluated the Fargo Area Study Concept as an alternative to the Project, Minnesota Power has determined that the substantial negative impact it has on North Dakota – Manitoba loop flow is compelling and makes the Concept an inferior alternative to the Project. The following discussion, starting in Section 7.4.3.1.1, will focus on the background of the Fargo Area Study Concept and the North Dakota – Manitoba loop flow phenomenon, the impact that the Concept has on North Dakota – Manitoba loop flow, and the implications for regional generation outlet capability, system performance, and long-term transmission system planning.

While some of the Concept studies included terminus points in North Dakota, under North Dakota Century Code § 49-22-09.1 a transmission facility that transmits hydroelectric power produced outside the United States, and which crosses any portion of North Dakota, must have the approval of the legislative assembly by concurrent resolution. Neither construction of such a facility, nor exercise of the right of eminent domain in connection with such construction can occur without the approval of the legislative assembly, adding significant uncertainty to any scenario including transmission facilities in North Dakota.

In addition, the Concept cannot achieve the timeline required by Minnesota Power's 250 MW Agreements. In anticipation of the Project's contractual June 1, 2020 in-service date, Minnesota Power began its public outreach efforts for permitting and routing the Project in mid-2012 in order to maintain the Project's schedule. To date, no utility has undertaken these activities on behalf of the Concept, implying that the Concept is nearly a year and a half behind the Project's effort. Through Minnesota Power's public outreach efforts for the Project, which included the agricultural areas of northwestern Minnesota through which the Concept would have to be routed, Minnesota Power uncovered significant challenges that would impact the routing of the Concept through those areas. These challenges could significantly delay the schedule of the Concept. Even if a utility stepped forward today to begin public outreach efforts for the Concept, it is highly improbable that the Concept could achieve a June 1, 2020 in-service date.

Finally, it must be noted that despite the time, attention and analysis given this Fargo Area Study Concept by a variety of entities, to date no entity has indicated a willingness to develop and fund the construction of such a transmission line.

7.4.3.1.1. Background and Relevant Studies

The Fargo Area Study Concept grew out of the July 2009 System Impact Study ("SIS") that was performed for the original transmission service requests from Manitoba Hydro to four utilities in the United States. The original TSRs were for delivery of 1,100 MW, including Minnesota Power's 250 MW, from Manitoba Hydro to the United States utilities (north to south) and 1,100 MW from the United States utilities to Manitoba Hydro (south to north). The initial study considered several 500 kV transmission options for increasing the capability of the Manitoba – United States interface by 1,100 MW flowing south or north.

The study was conducted by Siemens PTI and an ad hoc study group consisting of Manitoba Hydro, MISO, and several utilities in the Upper Midwest, including Minnesota Power. The two main transmission options considered in the SIS generally extended from the Winnipeg area into the United States via either northeastern Minnesota or the Red River Valley. The original transmission option through the Red River Valley actually did not end at Fargo but continued with 500 kV transmission extending to the Twin Cities.[34] The transmission option through northeastern Minnesota, which terminated at the existing Xcel Energy King Substation was eliminated due to feasibility concerns with engineering, operations, and routing to the King Substation.[35] A follow-up System Impact Study completed in April 2010 evaluated the specific impact of a new 500 kV interconnection from the Winnipeg area to the planned CapX2020 Bison Substation near Fargo, North Dakota.[36]

Starting in 2012, a series of sensitivities was conducted on the original TSR System Impact Studies to evaluate alternative transmission scenarios for achieving 250 MW, 750 MW, or 1,100 MW of increased transfer capability from Manitoba to the United States. These sensitivities have included a "Western Plan" extending new 500 kV transmission to the Barnesville area in western Minnesota, an "Eastern Plan" extending new 500 kV transmission to the Iron Range in northeastern Minnesota (the Project), and a "230 kV Option" extending new 230 kV transmission to the Iron Range. While MISO has not yet issued a final report for this series of studies, draft reports for the Eastern Plan and the Western Plan sensitivities are included in Appendix Q and the final reports will be filed when MISO makes them available.

A Fargo Area Study Concept has also been included, along with an Eastern plan (including the Project), in the MISO Wind Synergy and Northern Area studies, which are discussed in greater detail in Section 7.2, above. In these most recent MISO studies, the Fargo Area Study Concept consisted of a new Dorsey – Barnesville 500 kV line interconnecting to the Bison – Alexandria 345 kV line near Barnesville, Minnesota, and a second circuit on the Barnesville – Alexandria – Quarry – Monticello 345 kV line.

The Fargo Area Study Concept was also included in the Group Facility Study performed by Manitoba Hydro. The Facility Study was performed in order to evaluate network upgrade options, including a Fargo conceptual project and an Iron Range alternative (the Project), for facilitating up to 1,100 MW of additional transfer capability between Manitoba Hydro and the United States. In the Manitoba Hydro study, the Concept consisted of a Dorsey – Bison (Fargo) 500 kV tie line, with an optional second 500/345

[34] MHEB Group TSR System Impact Study Executive Summary, July 17, 2009.
[35] MH TSR 500 kV Facility Study Meeting Minutes, February 16, 2010.
[36] MHEB Group TSR System Impact Study Transmission Options W.1 and W.2, April 19, 2010.

kV transformer at Bison and second circuit on the Bison – Monticello 345 kV line. [37] While the final draft of the Manitoba Hydro Facility Study has not yet been released, Minnesota Power has reviewed a preliminary report which may be made available upon request. Minnesota Power will provide the final report when available.

In addition, other utilities have studied the Fargo Area Study Concept. Perhaps the most comprehensive study of this Concept, the Manitoba Hydro Transmission Expansion ("MANTEX") Study, was performed by Siemens PTI on behalf of several CapX2020 utilities. A final report from the MANTEX Study was issued in August 2012. Minnesota Power and Manitoba Hydro participated in the early stages of the MANTEX Study, but were not involved in the model development, analysis, or final recommendations of the study. The purpose of the MANTEX Study was to identify a conceptual transmission plan for inclusion in the MISO Manitoba Hydro Wind Synergy Study, discussed in Section 7.2.2, above.[38] Several transmission plans were considered, but the plan recommended by the MANTEX Study to achieve 1,100 MW of incremental Manitoba - United States transfer capability included a new 500 kV tie line from the Dorsey Substation in Manitoba to the Bison Substation near Fargo, along with additional 500/345 kV transformation at Bison and a second 345 kV circuit from Bison – Alexandria – Quarry – Monticello for higher Manitoba – United States transfer levels.[39] An additional study by the same group of utilities later considered the impact of moving the United States endpoint of the tie line from the existing Bison Substation near Fargo to a new Barnesville Substation near Barnesville, Minnesota.[40]

7.4.3.1.2. Concerns With Fargo Area Study Concept

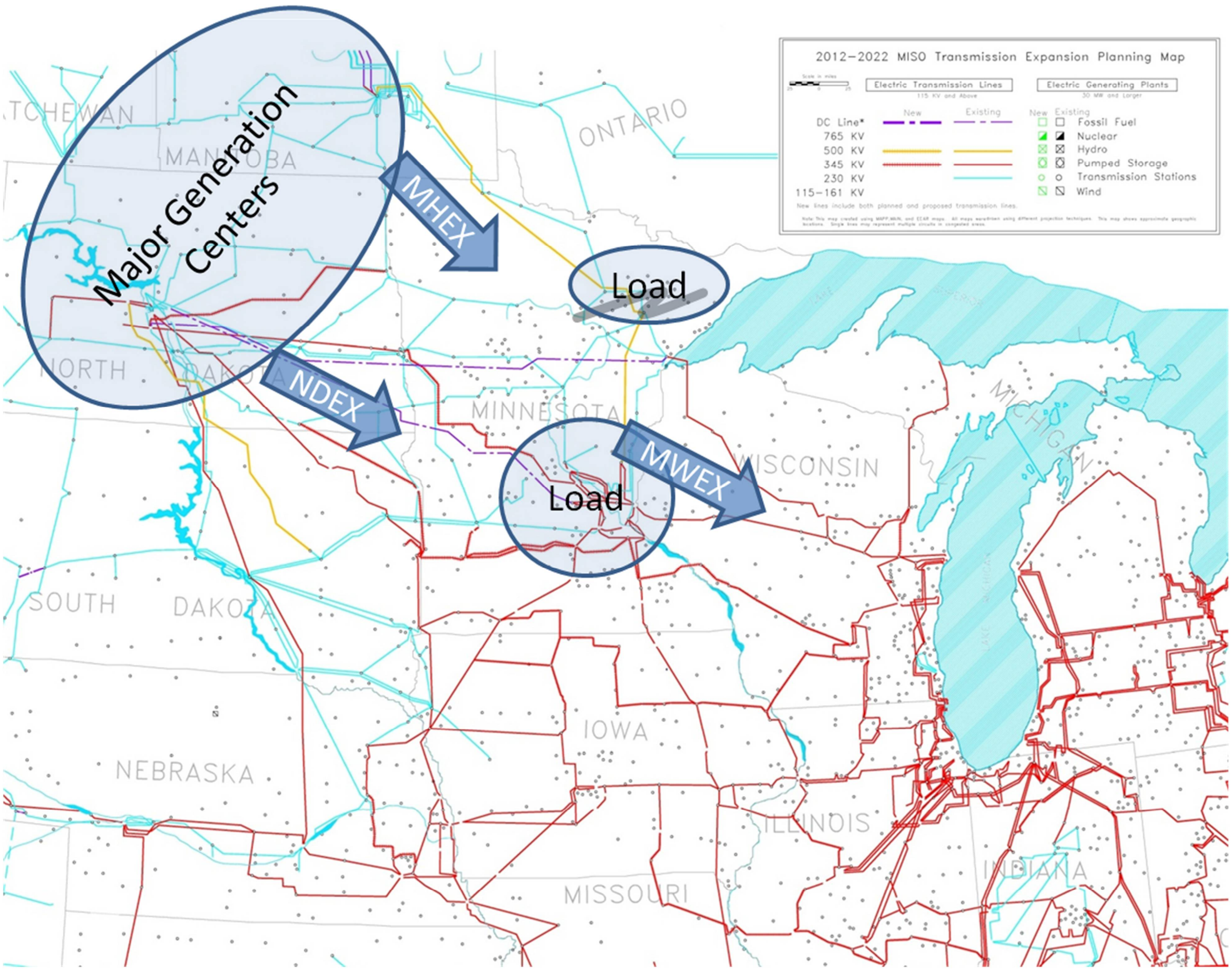
In many study scenarios, the Fargo Area Study Concept exhibits similar performance and benefits when compared with the Project. However, when some of the most stressed study scenarios are considered, serious performance flaws with the Concept compared to the Project become apparent. The fundamental reason for this is that development of a new 500 kV line from Winnipeg to the Fargo area would dramatically aggravate the well-documented North Dakota – Manitoba "loop flow" phenomenon by introducing a very low impedance path between North Dakota and Manitoba. This would ultimately limit the long-term generation export capability of North Dakota, Manitoba, or both, causing generation in North Dakota to compete with generation in Manitoba for the same congested transmission path (the Dorsey – Forbes 500 kV line).

On a regional level, power has historically flowed from major generation centers in Manitoba and North Dakota to load centers on the Iron Range and in the Twin Cities, and further east into Wisconsin. The most stressed cases, and therefore those that have had

[37] Manitoba Hydro Preliminary Group Facility Study Report, October 2, 2013, p. 4.
[38] MANTEX Study, August 1, 2012, p. viii.
[39] MANTEX Study, August 1, 2012, p. vii.
[40] Minnesota Route Transmission Option Study, April 3, 2013.

the most serious reliability and economic impacts, have been those with high simultaneous export levels from Manitoba and North Dakota causing massive amounts of power to flow from those areas to load centers on the Iron Range, in the Twin Cities, and in Wisconsin. This trend is shown in Figure 7.4A, below.

FIGURE 7.4A: Historical Trend of Regional Power Flow



Three interfaces, shown in Figure 7.4A, have historically been used to measure the level of stress in a case and identify regional power flow limits. First, the Manitoba Hydro Export ("MHEX") interface is a measure of the sum of the power flowing on the four existing Manitoba – United States tie lines described in Section 7.4.1, above. Current total firm transfer capability on MHEX is 2,175 MW southward and 700 MW northward.[41] The Project is designed to increase firm transfer capability on MHEX to 2,925 MW southward and 1,450 MW northward while preserving system reliability at existing levels or better.

Second, the North Dakota Export ("NDEX") interface has traditionally been defined by the sum of the power flowing on the tie lines extending from North Dakota to the north (Manitoba), south (South Dakota), and east (Minnesota). Today, this includes 19 high voltage (115+ kV) tie lines, with two additional components located in Minnesota that must be netted out. NDEX currently has a studied simultaneous limit of 2,080 MW, though recent studies have suggested that planned system improvements will modify the nature of the NDEX limit and potentially increase it to 2,200 MW or more.[42] The NDEX interface represents the location where North Dakota historically separated from the rest of the regional power system. While recent and anticipated changes on the system, including two new tie lines across the historical NDEX boundary, have largely eliminated the need for the historical NDEX as a stability interface, NDEX remains a good proxy for measuring the total generation export from North Dakota to the rest of the system as well as the impact of this export on other interfaces like MHEX and Minnesota-Wisconsin Export (described below). It is in this context that the North Dakota Export interface will be referred to throughout the rest of this Application.

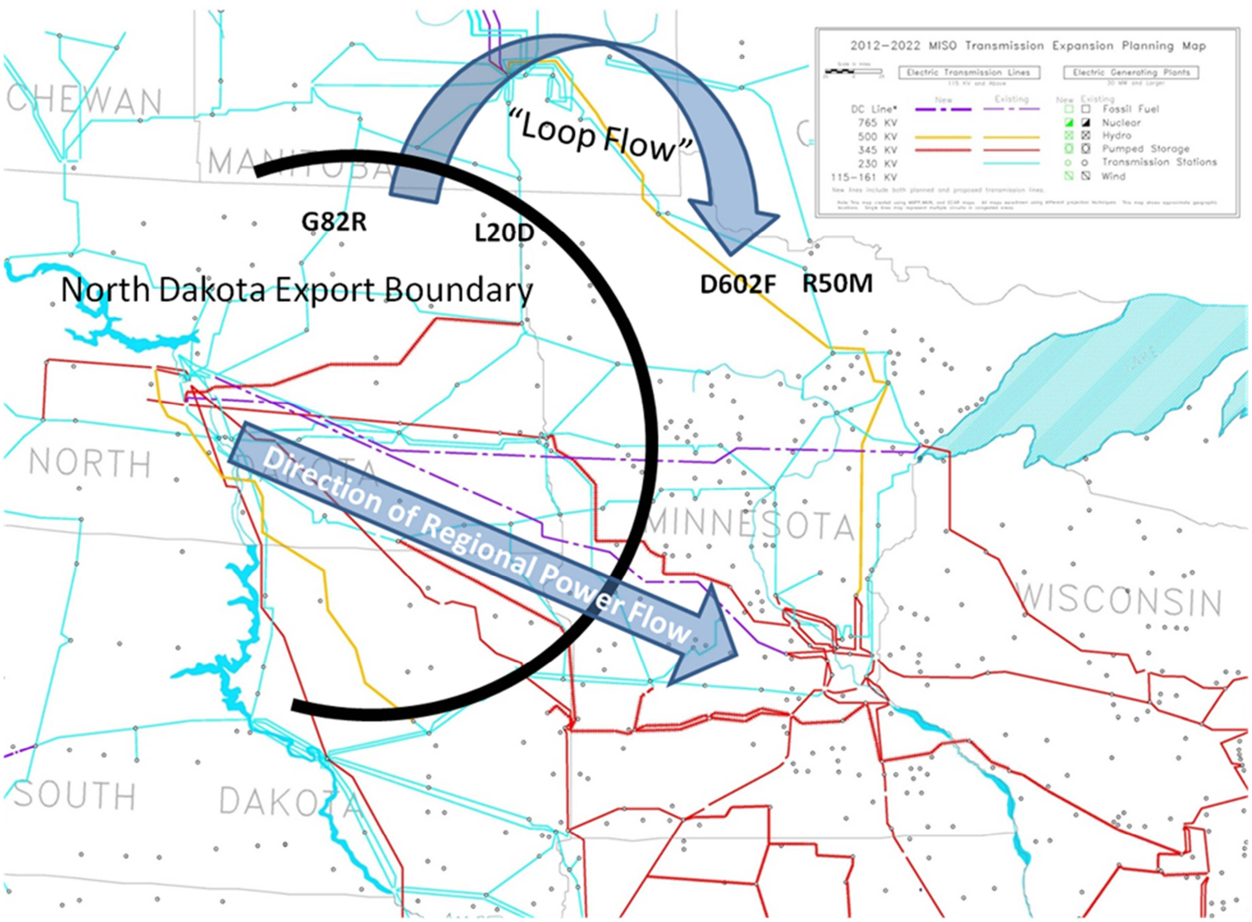
Third, the Minnesota-Wisconsin Export ("MWEX") interface is defined by the sum of the power flowing on two lines: the King – Eau Claire – Arpin 345 kV line and the Arrowhead – Stone Lake – Gardner Park 345 kV line. Currently, export capability from Minnesota to Wisconsin on these two lines is limited to 1,665 MW; beyond this MWEX level, system instability is likely to occur for certain fault events on the King – Eau Claire 345 kV line. The future construction of the Hampton Corners (southeast Twin Cities) – North Rochester – Briggs Road (Lacrosse, WI) 345 kV line and the Briggs Road – North Madison – Cardinal (Madison, WI) 345 kV line will likely improve the dynamic performance of the MWEX interface and increase export capability from Minnesota to Wisconsin.

Regional power system analysis has consistently shown that there is an existing North Dakota – Manitoba "loop flow" phenomenon where higher levels of North Dakota export

[41] Manitoba Hydro Preliminary Group Facility Study Report for MHEM, October 2, 2013, p. 14.
[42] Impact of CapX Facilities on North Dakota Export for the Year 2016 Report, June 2012.

will flow into Manitoba on the two 230 kV tie lines between Manitoba and North Dakota (G82R and L20D) and then back down into Minnesota, primarily on the Dorsey – Forbes 500 kV line (D602F). This condition is due to the physics of the transmission system and related to the fact that electricity does not follow any one path to get from "Point A" to "Point B", but actually flows on all possible paths based on the impedance of the system. This concept is illustrated in Figure 7.4B, below.

FIGURE 7.4B: North Dakota - Manitoba Loop Flow



The amount of loop flow varies with NDEX and MHEX levels. At very low NDEX levels, there is very little loop flow due to low North Dakota generation levels. As the amount of generation being exported from North Dakota increases, loop flow through Manitoba increases proportionately. In practice, loop flow does not typically result in large power flows north on the North Dakota – Manitoba tie lines (G82R and L20D). Rather, when North Dakota loop flow is superimposed onto Manitoba – United States exports, the typical result is a reduction in total power flow south into North Dakota on G82R and L20D and an increase in total power flow south into Minnesota on D602F and R50M. This is illustrated in Figures 7.4C and 7.4D.

Figure 7.4C shows the separate power flows on the Manitoba interface due to Manitoba export and North Dakota loop flow.

FIGURE 7.4C: Power Flows on the Manitoba/United States Interface

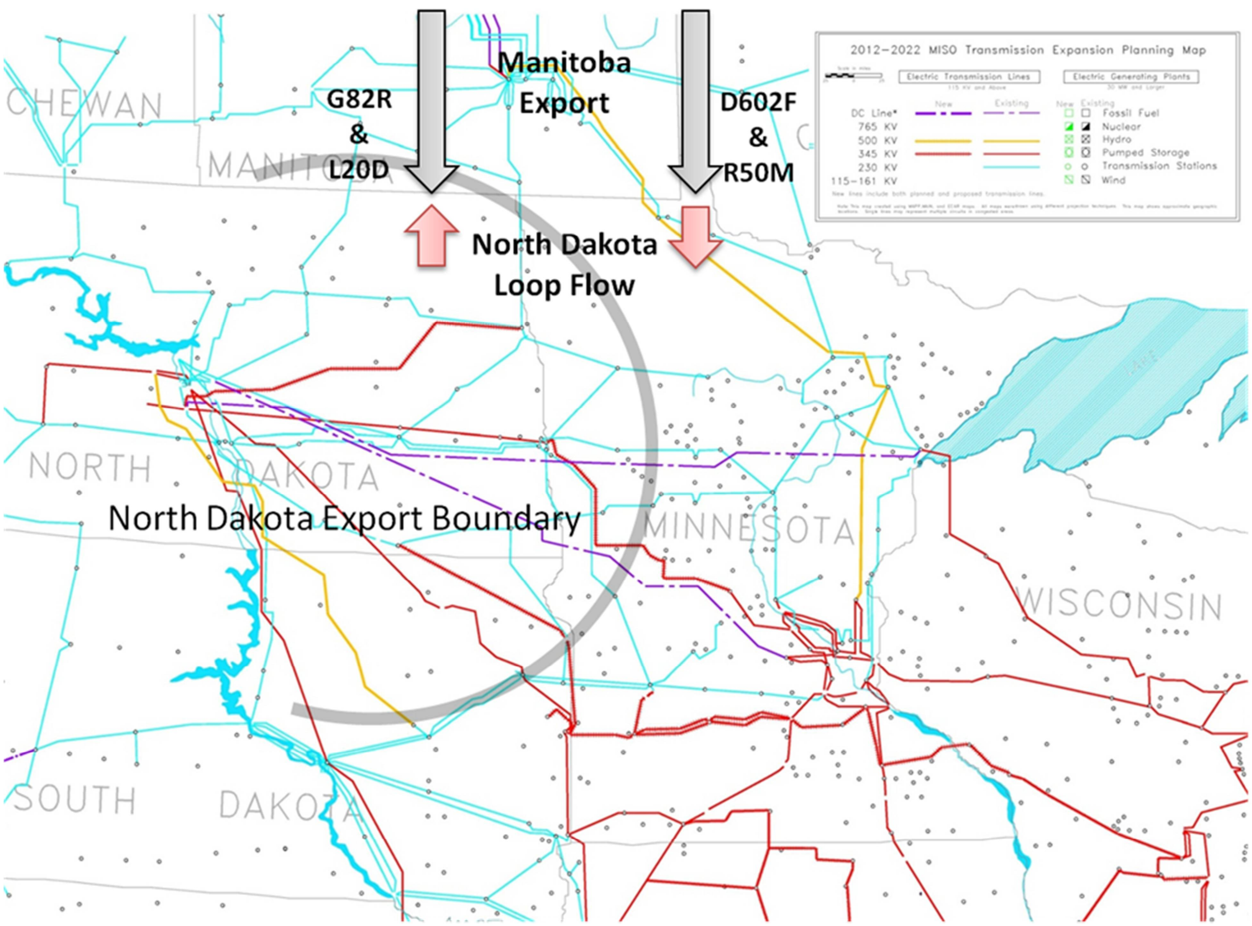
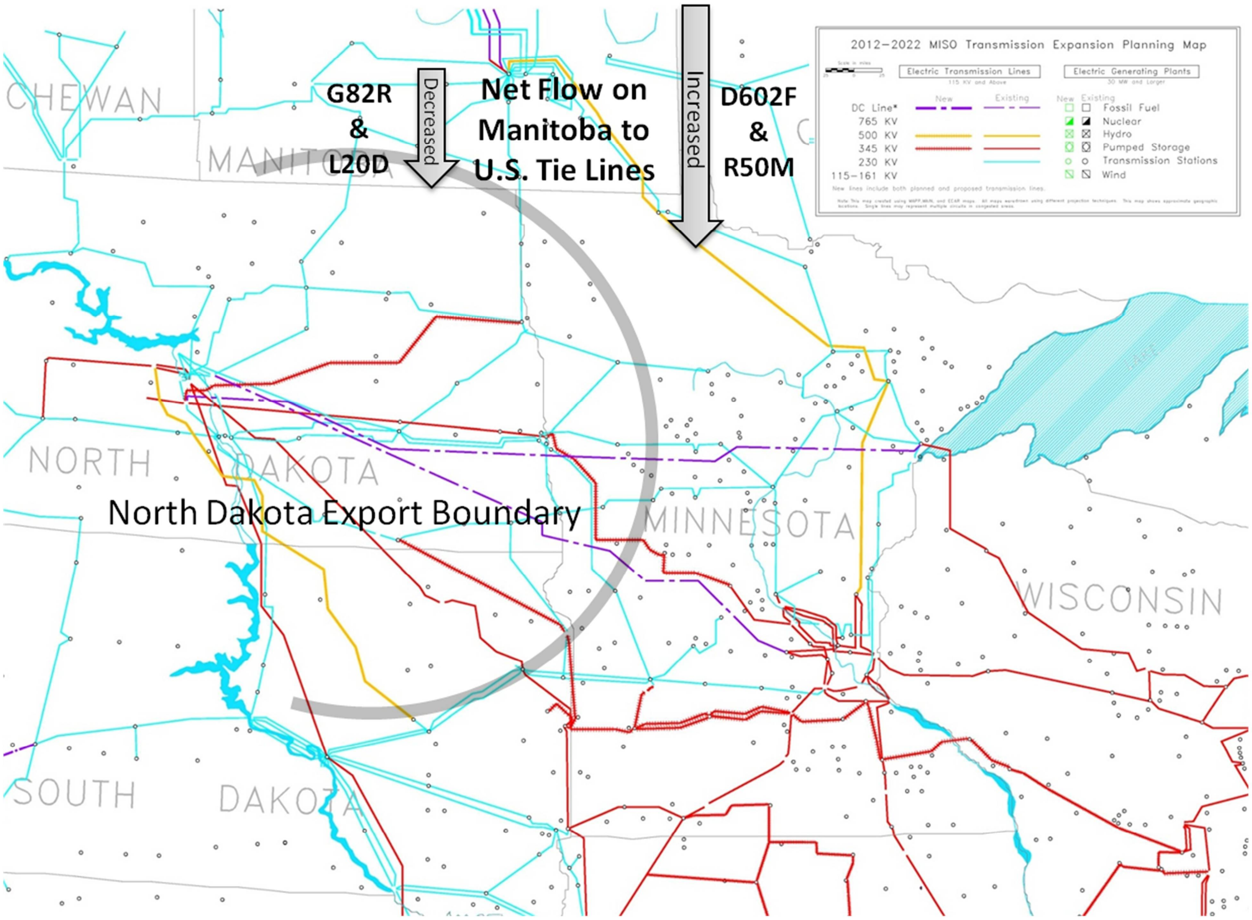


Figure 7.4D shows the net effect of North Dakota loop flow – less power flow south on G82R and L20D, and more power flow south on D602F and R50M.

FIGURE 7.4D: Net Effect of Loop Flow on the North Dakota/United States Interface



This North Dakota – Manitoba Loop Flow phenomenon was recently documented in the CapX2020 study report "Impact of CapX Facilities on North Dakota Export for the Year 2016," where it was found that even with the new Phase 1 CapX2020 facilities in service, thermal and stability constraints on NDEX exist due to loop flow. The study found that the simultaneous NDEX stability limit, with MHEX at 2,175 MW, MWEX at 1,665 MW, and the new CapX lines in service, is established at approximately 2,200 MW by transient undervoltages on the 161 kV system in Northwest Wisconsin. The next limitation on NDEX was encountered in the study at approximately 2,500 MW when the

Roseau series capacitors on D602F overloaded.[43] Both of these constraints are directly attributable to North Dakota – Manitoba loop flow, as exports from North Dakota flow through Manitoba and down on D602F, pushing more power through northeast Minnesota into northwest Wisconsin, causing stability issues on the MWEX interface and eventually overloading the Roseau series capacitor banks.

7.4.3.1.3. Impact of Fargo Area Study Concept Line Compared To the Project

The Fargo Area Study Concept would introduce a new low-impedance path between North Dakota and Manitoba, which would dramatically aggravate the existing loop flow issue. One way to conceptualize the loop flow issue and the impact of a new 500 kV tie line is illustrated in the figures below. Conceptually, each of the Manitoba – United States tie lines can be thought of as a pipe. The size of the pipe corresponds to the relative impedance of the transmission line. Since lower impedance, higher voltage lines facilitate and draw more power flow, the largest pipe will represent the lowest impedance, highest voltage transmission line.

[43] Impact of CapX Facilities on North Dakota Export for the Year 2016 Report, June 2012, p. 7.

Figure 7.4E shows the path for loop flow in the existing system. This path is made up of two small pipes from within the North Dakota Export boundary into Manitoba (G82R and L20D), one small pipe from Manitoba into northeastern Minnesota (R50M), and one very large pipe from Manitoba into eastern Minnesota. (D602F). While D602F is a very low impedance path (a very large pipe) for loop flow, the amount of loop flow in the existing system is limited by the higher relative impedances of G82R and L20D (smaller pipes).

FIGURE 7.4E: Loop Flow Conceptualization (Existing System)

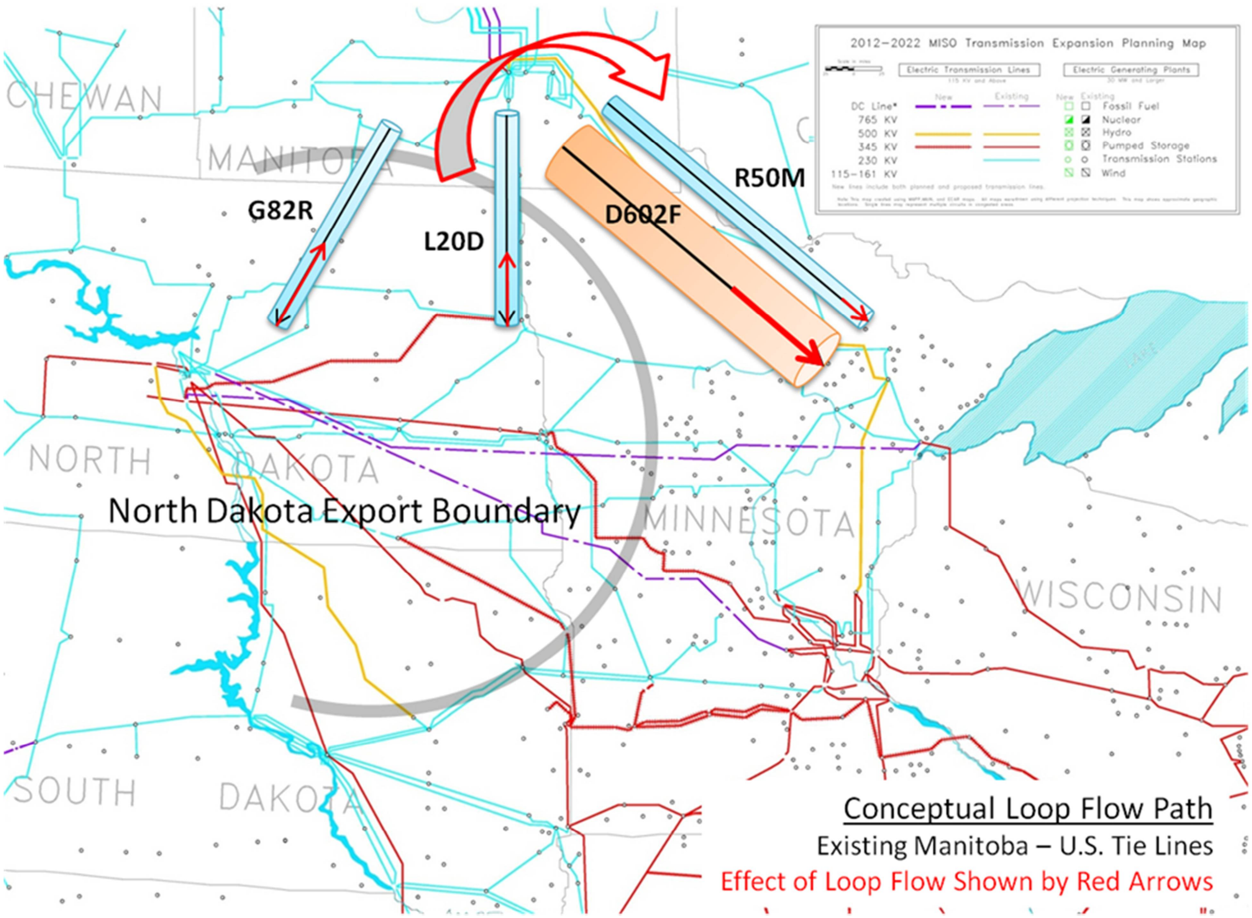
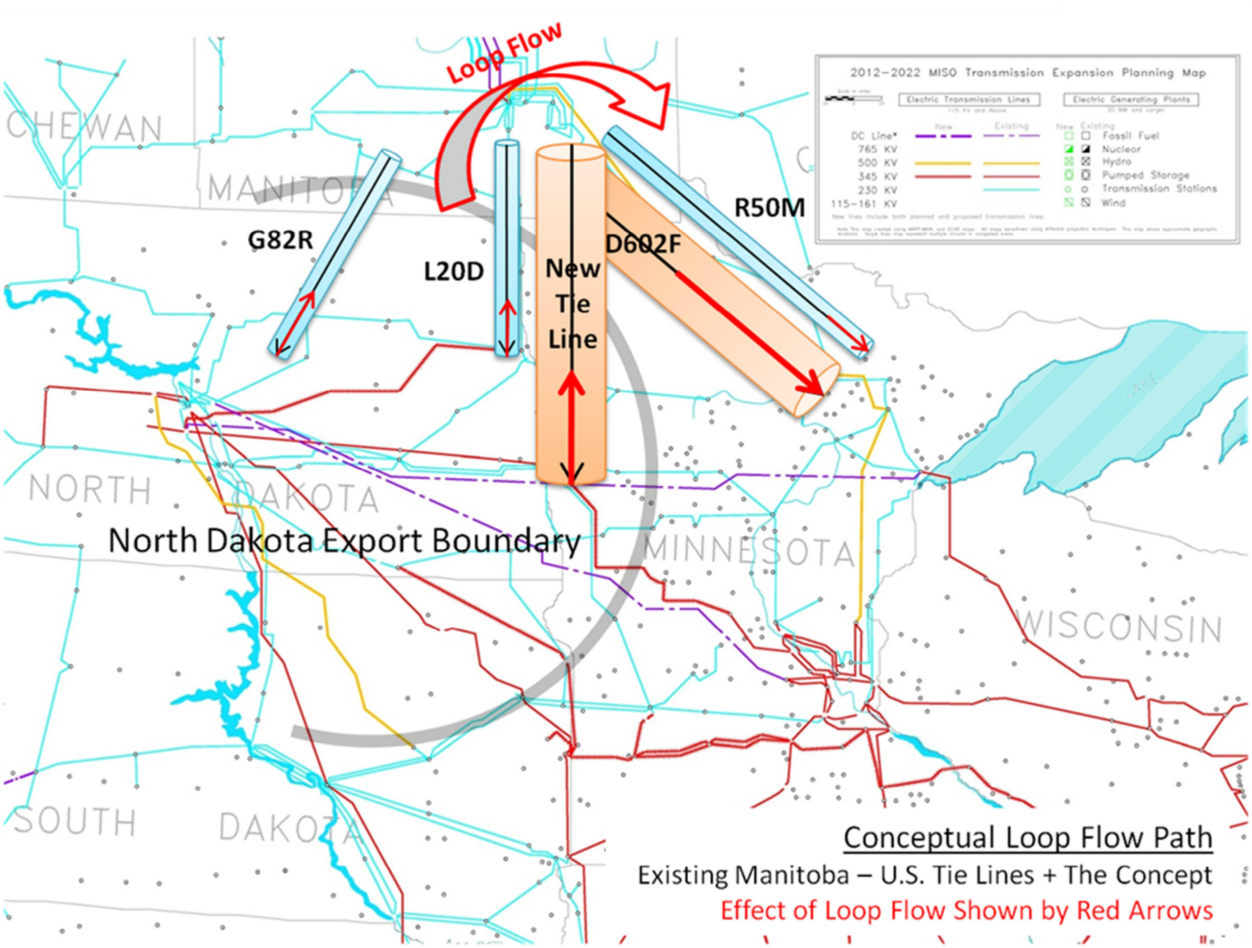


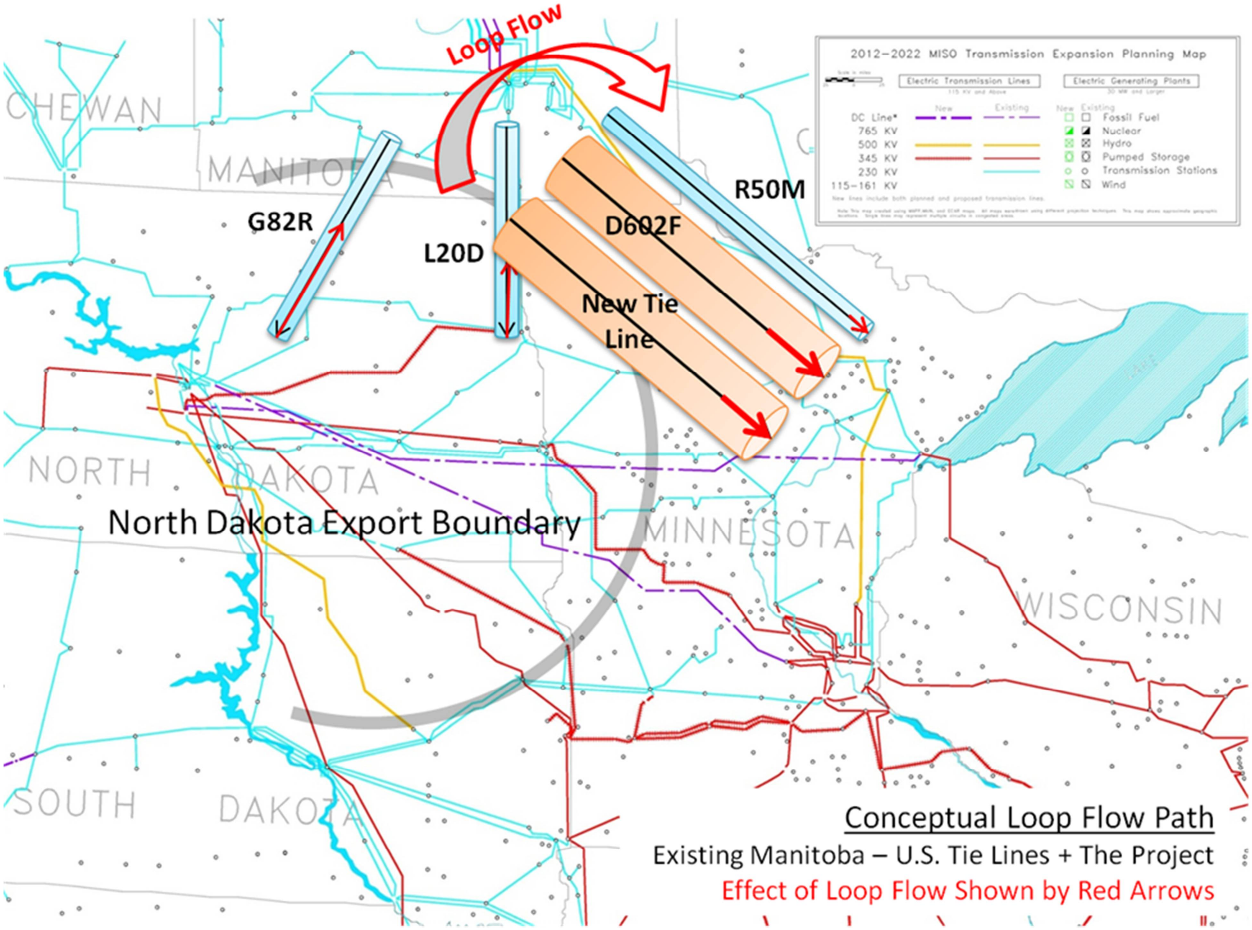
Figure 7.4F shows the path for loop flow with the addition of a new Dorsey – Barnesville 500 kV line (the Concept). The Fargo Area Study Concept would introduce a new, very large pipe from within the North Dakota Export boundary into Manitoba. Since the new tie line would strongly connect North Dakota and Manitoba, power generated in North Dakota would have one continuous very low impedance path (one long, very large pipe) to flow from North Dakota into Manitoba and then back in the United States. In practice, the result would be that the higher the North Dakota Export is, the less power a new Dorsey – Barnesville 500 kV line would carry from Manitoba to the United States. This would cause more power to flow on D602F, overloading the line much sooner than it would otherwise be overloaded if the new tie line did not connect North Dakota and Manitoba, and severely limiting simultaneous export capability absent any upgrades or new transmission development.

Figure 7.4F: Loop Flow Conceptualization
(Fargo Area Study Concept)



Finally, Figure 7.4G shows the path for loop flow with the addition of a new Dorsey – Blackberry 500 kV line (the Project). The Project introduces a new, very large pipe electrically parallel with D602F from Manitoba to the east, outside the North Dakota Export boundary. Even though D602F and the Dorsey – Blackberry 500 kV line together provide a very low impedance path (two very large pipes) for loop flow, the amount of loop flow facilitated by the Project is still limited by the higher relative impedances of G82R and L20D (smaller pipes), the only tie lines from North Dakota to Manitoba. In practice, the result is less interaction between power generated in North Dakota and power generated in Manitoba, and higher simultaneous export capability absent additional transmission development.

Figure 7.4G: Loop Flow Conceptualization (Project)



7.4.3.1.4. Confirming Studies

As mentioned above, regional power system analyses, like the recent CapX NDEX Study, have consistently demonstrated that the North Dakota – Manitoba loop flow phenomenon is real and that it can cause real constraints on generation exports from

North Dakota, Manitoba, or both. The common path for loop flow, and therefore the main thermal constraint associated with it, is the Dorsey – Forbes 500 kV line (D602F). As described above in Section 7.4.1, the rating of D602F is currently limited to 2,000 amps (1,732 MVA), primarily due to the rating of the Roseau series capacitors. While it is technically feasible to increase the rating of D602F from 2,000 to 2,500 amps (2,165 MVA) by upgrading the Roseau series capacitors and some line terminal equipment, this upgrade would be highly complex and raise a number of potential issues relating to the operation of the line and terminal equipment as well as the reliability of the regional transmission system.

Upgrading D602F beyond 2,500 amps would not be feasible, meaning that the ultimate rating achievable on D602F is 2,165 MVA. This is because an additional margin is needed above 2,500 amps to accommodate temporary increases in loading in order to avoid overloading substation equipment. Since the substation equipment at both ends is limited to 3,000 amps and upgrading this equipment is not practical, there is very little room for margin above 2,500 amps. In addition to substation equipment limitations there would also be technical and reliability concerns with operating the line significantly above 2,500 amps.[44]

Several recent studies have demonstrated that the Fargo Area Study Concept would facilitate significantly more North Dakota – Manitoba loop flow than a new 500 kV line from Winnipeg to the Iron Range (the Project). While various solutions have been proposed, studies performed by Manitoba Hydro, Minnesota Power, and other utilities consistently demonstrate that the Fargo Area Study Concept would result in significant increases in D602F line loading compared to the Project. As mentioned above, the increased flow on D602F is a direct result of North Dakota – Manitoba loop flow and the main thermal constraint associated with this phenomenon.

7.4.3.1.4.1. Manitoba Hydro Facility Study

Manitoba Hydro's Facility Study Report demonstrates that increasing NDEX and MWEX levels cause overloads of D602F for the Fargo injection (the "Concept"). In fact, pre-contingent overloading of D602F due to North Dakota – Manitoba loop flow was observed for the Concept when NDEX, MWEX, and MHEX were modeled at maximum simultaneous transfer levels. In contrast, no pre-contingent D602F overloads were observed for the Iron Range injection (the Project) under this system condition because power flow was more evenly distributed on the two 500 kV lines. The report states that the overloads of D602F caused by the Concept may ultimately require upgrade of the Roseau series compensation and additional reactive power support at Forbes of approximately 300 MVAr.[45]

[44] White Paper on Series Capacitor Upgrade Issues.
[45] MH Preliminary Group Facility Study Report for MHEM, October 2, 2013, pp. 7-8.

7.4.3.1.4.2. Dorsey-Iron Range 500 kV Project Preliminary Stability Analysis

Minnesota Power found similar results in its own preliminary stability analysis on the new 500 kV tie line options. As the December 5, 2012 Dorsey – Iron Range 500 kV Project Preliminary Stability Analysis study report (included as Appendix N) explained:

> The purpose of this study was to conduct a preliminary power system stability assessment of both the Minnesota Power Dorsey – Iron Range 500 kV [the Project] and the proposed Dorsey – Bison 500 kV [the Concept] projects in order to:
>
> - Assess the impact of the proposed 500 kV lines on the North Dakota – Manitoba loop flow issue by determining NDEX restrictions due to 602 line [D602F] loading limitations with 1100 MW of additional Manitoba to United States power transfer.
>
> - Assess the impact of the proposed 500 kV lines and 1100 MW of incremental Manitoba to United States transfers on the Minong 161 kV transient voltage performance for King – Eau Claire – Arpin (PCS) disturbance.
>
> - Determine the amount of Manitoba Hydro DC reduction initiated for faults that result in the tripping of 602 line.[46]

At the time the preliminary study was being performed, the endpoint of the Fargo Area Study Concept had not yet been shifted from the planned CapX2020 Bison Substation to the conceptual Barnesville Substation. Since the probable location of the conceptual Barnesville Substation is electrically very close to the Bison Substation, this shift would not have made a large difference in the results. In Minnesota Power's analysis, as in Manitoba Hydro's, the Fargo Area Study Concept was found to aggravate North Dakota – Manitoba loop flows, causing pre-contingent overloading of D602F during high simultaneous NDEX and MHEX transfers. The Iron Range option (the Project) was found to facilitate the same level of high simultaneous exports from Manitoba and North Dakota without overloading D602F. The report concludes:

> The Dorsey – Iron Range 500 kV project provides a path for an incremental 1100 MW of MH-US transfers that is not impacted by North Dakota – Manitoba loop flow issues that create overloads of the Riel – Forbes 500 kV line (602 line). In the cases studied, MHEX transfers of 3290 MW simultaneous with NDEX transfers of 2217 MW were achievable without overloading the 602 line. Due to its negative impact on the loop flow issue,

[46] Appendix N, p. 3.

the Dorsey – Bison 500 kV project with 1100 MW [incremental] MH–US transfers overloads 602 line by 106% at the same level of NDEX (2224 MW).[47]

7.4.3.1.4.3. Manitoba - United States Transmission Development Wind Injection Study

Minnesota Power commissioned Excel Engineering to perform a Wind Injection Study that was specifically designed to identify and evaluate the incremental wind injection capability at the border between Minnesota and the Dakotas in conjunction with 1,100 MW of new Manitoba to United States transmission service requests and their associated facilities. The study (March 1, 2013 Report and Appendix included as Appendix O) included two alternative Manitoba to United States transmission configurations: a Fargo alternative (the Concept), and an Iron Range alternative (the Project).

In general, the Wind Injection Study found that the Iron Range plan allowed for significantly higher levels of wind injection simultaneous with 1,100 MW of new Manitoba to United States transfers. According to the study report, the Iron Range plan can support 500 MW of incremental North Dakota wind injection directly without any additional transmission upgrades, whereas, the Fargo alternative would require significant transmission upgrade investment. With relatively modest transmission upgrade costs, the Iron Range plan will support higher levels of wind injection (1,000 – 1,500 MW). The Fargo alternative would not be able to achieve similar levels due to limitations on D602F.[48]

The disparity identified by the Wind Injection Study between the Iron Range plan and the Fargo alternative is directly attributable to North Dakota – Manitoba loop flows. In the Wind Injection Study, the new 500 kV tie line associated with the Fargo alternative did not provide enough balance with the existing 500 kV tie line, resulting in pre-contingent overloads of D602F for relatively moderate levels of incremental North Dakota wind injection. Even after adding the second circuit on the Bison (Fargo) – Monticello 345 kV line and a new 345 kV line from Bison to Brookings County, the incremental North Dakota wind injection achievable with the Fargo alternative was limited to 670 MW due to D602F overloads.[49]

In general, the Wind Injection Study assumed that upgrading D602F beyond the 2,000 amp limit was beyond the scope of the upgrades considered for the study due to the complexity and uncertainty associated with it.[50] When a sensitivity was performed to determine the cost of transmission upgrades beyond the 2,000 amp limit on D602F for

[47] Id., p. 2.
[48] Appendix O, p. 2.
[49] Appendix O, p. 21.
[50] Id.

the Fargo alternative, it was found that the incremental cost of the Fargo alternative was still higher than that of the Iron Range plan for the same levels of North Dakota wind injection. A larger concern raised by this sensitivity is the level of North Dakota wind injection for which the Fargo alternative actually caused D602F line loading to exceed the 2,500 amp limit. As explained above, beyond 2,500 amps, further capacity upgrades on D602F are not feasible. None of the various configurations of Fargo alternatives considered in the sensitivity was able to facilitate 2,000 MW of incremental North Dakota wind injection without causing loading on D602F to exceed the 2,500 amp limit. In contrast, every one of the Iron Range configurations considered in the study was capable of facilitating 2,000 MW of incremental North Dakota wind injection without causing loading on D602F to exceed the existing 2,000 amp limit.[51]

7.4.3.1.4.4. Manitoba Hydro Transmission Expansion Study and Related Studies

Even the substantial collection of studies performed by proponents of the Fargo Area Study Concept demonstrates that building a new tie line from Winnipeg to the Fargo area would have a negative impact on North Dakota – Manitoba loop flow. In nearly every one of these studies, overloads of D602F associated with development of a Dorsey – Bison (or Barnesville) 500 kV line are identified. Minnesota Power and Manitoba Hydro were not involved in the model development, analysis, or final recommendations of any of the studies discussed below, but have reviewed the full study reports and appendices provided by the utilities involved.

In the MANTEX Study, the system upgrade costs associated with Option B – a new 60 percent series compensated 500 kV tie line from Dorsey to Bison with a single 500/345 kV transformer located at Bison – included $11 million for upgrading the Roseau series capacitors. The report states that the series capacitors and other elements "become thermally overloaded by the increased transfer under certain contingency conditions."[52] As discussed in Section 7.4.1. above, upgrading the Roseau series capacitors would be highly complex and raise a number of potential issues relating to the operation of the line and terminal equipment, as well as the reliability of the regional transmission system. A more comprehensive recent estimate of the costs associated with this upgrade is $30-50 million.[53] In the MANTEX Study, Option B, with Roseau series capacitor upgrade and other system upgrades, is assumed to be capable of facilitating 1,100 MW of increased Manitoba – United States transfers.[54]

The Minnesota Route Transmission Option Study evaluated the impact of moving the United States endpoint of the MANTEX conceptual plan from the Bison Substation near

[51] Appendix O, pp. 55-56.
[52] MANTEX Study, August 1, 2012, p. vii.
[53] White Paper on Series Capacitor Upgrade Issues.
[54] MANTEX Study, August 1, 2012, p. vii.

Fargo, North Dakota, to a new substation near Barnesville, Minnesota. In this study, Option B' – a new 60 percent series compensated 500 kV tie line from Dorsey to Barnesville with a single 500/345 kV transformer located at Barnesville – is found to have a similar, even slightly greater, impact on D602F line loading for the 1,100 MW incremental transfer scenario. While MANTEX Option B resulted in D602F loading of 1,820 MW (approximately 105 percent of its 1,732 MW rating), MN Route Option B' resulted in D602F loading of 1,830 MW (approximately 106 percent of its 1,732 MW rating).[55]

The Eastern MN 500 kV Transmission Study was designed to evaluate the performance of a conceptual eastern Minnesota 500 kV tie line project and compare it to MANTEX Option B. The eastern Minnesota 500 kV project ("Option T") studied by the proponents of the Fargo Area Study Concept consisted of a new 50 percent series compensated 500 kV tie line from the Riel Substation in Manitoba to the existing Shannon Substation on the Iron Range in Minnesota and a double circuit 345 kV line from Shannon to the existing Arrowhead Substation near Duluth, Minnesota. While there are considerable differences between MANTEX Option T and the Great Northern Transmission Line Project, the relative performance when compared to MANTEX Option B appears similar. In this study, the Riel – Shannon 500 kV line was found to carry more power than the Dorsey – Bison 500 kV line in the 1,100 MW incremental transfer scenario. For MANTEX Option T, the new 500 kV tie line to Shannon was found to carry 1,151 MW; this is the entire 1,100 MW incremental Manitoba – United States transfer plus an additional 51 MW of existing Manitoba – United States transfers. The corresponding power flow on D602F was 1,608 MW, just shy of 93 percent of its 1,732 MW rated capacity. In the study report, this is compared in a table to MANTEX Option B, for which the new tie line carries only 1,032 MW and D602F is forced to carry 107 percent of its rated capacity.[56] These results clearly demonstrate the disparate impact of the two projects on North Dakota – Manitoba loop flows. The new 500 kV tie line in the eastern Minnesota option (MANTEX Option T) would actually relieve the negative impacts of North Dakota – Manitoba loop flow by providing an electrically parallel path to D602F. Because it would be electrically parallel to D602F, MANTEX Option T would be capable of sharing Manitoba – United States transfers more uniformly with the existing 500 kV tie line. In contrast, the new 500 kV tie line in the Concept (MANTEX Option B) would not relieve loop flow, but instead would provide a new low impedance path for North Dakota – Manitoba loop flow, causing increased loading on D602F relative to the eastern Minnesota option.

The Dakota Wind Study performed by the Fargo Area Study Concept proponents is similar in theory to Minnesota Power's Wind Injection Study. The purpose of the Dakota Wind Study was to identify the additional transmission upgrades needed to transfer

[55] Minnesota Route Transmission Option Study, April 3, 2012, p. xi.
[56] Eastern MN 500 kV Transmission Study, August 31, 2012, p. 7-3.

varying amounts of wind power from the Dakotas simultaneously with incremental Manitoba – United States transfers and the associated conceptual transmission plans identified by the MANTEX study.[57] Even the Dakota Wind Study, which assumes increased capacity on D602F as part of MANTEX Option B and nowhere describes the actual flow on the Manitoba to United States tie lines associated with increasing levels of wind injection in the Dakotas, demonstrates the presence and impact of North Dakota – Manitoba loop flow associated with the Fargo Area Study Concept. With MHEX at 3,575 MW (an incremental 1,400 MW beyond today's limit), incremental Dakota wind transfer capability was limited to 1,773.4 MW due to overloading of the Arrowhead phase shifting transformer.[58] This overload is directly attributable to North Dakota loop flows coming down D602F into northeastern Minnesota and then flowing through the Arrowhead phase shifting transformer onto the Arrowhead – Stone Lake – Gardner Park 345 kV line. In the Dakota Wind Study no further incremental Dakota wind injection was considered after the Arrowhead phase shifting transformer overloaded.[59]

7.4.3.1.4.5. New Tie Line Loop Flow Impact Study

Minnesota Power recently kicked off the New Tie Line Loop Flow Impact Study ("Loop Flow Impact Study") to further investigate the nature of the North Dakota – Manitoba loop flow phenomenon and compare the impact that various configurations of a new 500 kV Manitoba – United States tie line have on loop flow. The Loop Flow Impact Study compares the performance of the existing system (i.e., no new tie line) with several different transmission configurations involving Western (Fargo Area Study Concept) and Eastern (the Project) 500 kV tie lines. Four different model series with widely varying initial MHEX and NDEX conditions are being used for the Loop Flow Impact Study with minimal modifications. While some initial results from the Loop Flow Impact Study are available and have been used to develop the discussion below, Minnesota Power does not expect that a final report will be available until January 2014.[60]

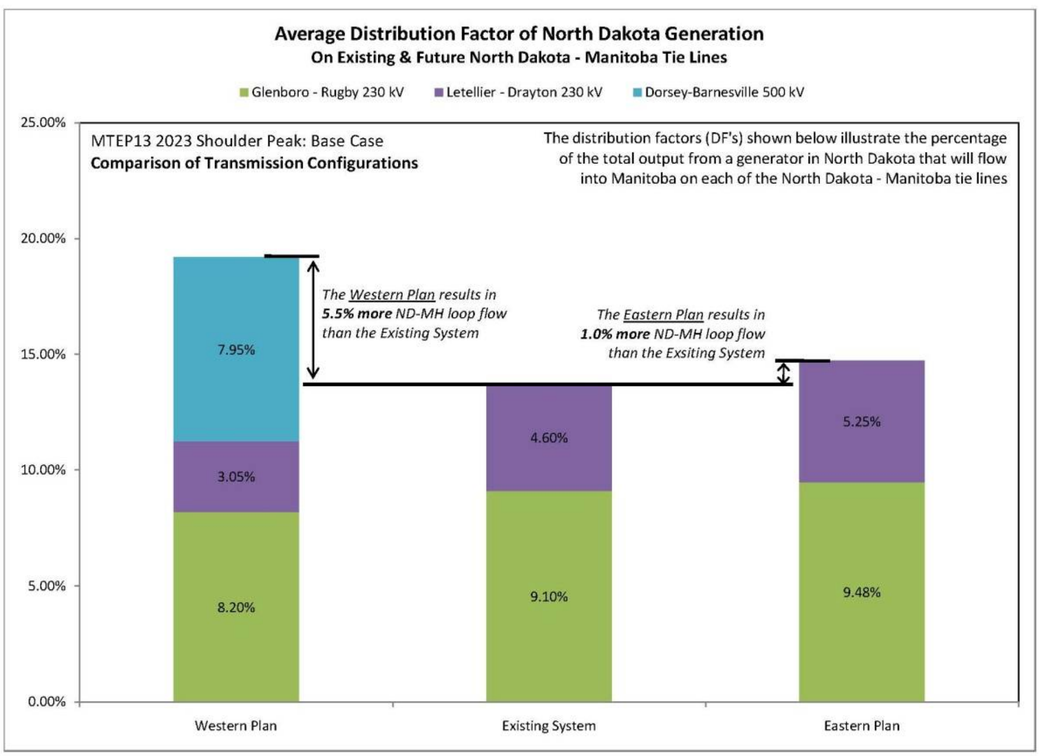
Three general metrics will be used to evaluate the relative impact that each transmission configuration has on North Dakota – Manitoba loop flow. All three metrics are based on the calculation of distribution factors describing the percentage of the total output of a conceptual new generator in North Dakota that will flow on each of the existing and new Manitoba – United States tie lines. A composite North Dakota generation distribution factor will be calculated for each tie line based on the distribution factors for individual injection points (proxy new generators) at several locations in North Dakota.

---

[57] Dakota Wind Study, August 31, 2012, p. v.
[58] Dakota Wind Study, August 31, 2012, pp. vii-viii.
[59] Dakota Wind Study, August 31, 2012, p. viii.
[60] The draft Study Scope outlining the intended scope and methodology of the Loop Flow Impact Study is attached as Appendix P.

The first metric being used to evaluate the relative loop flow impact of each transmission configuration is the total North Dakota – Manitoba loop flow associated with the configuration. The total loop flow can be calculated by totaling up the North Dakota generation distribution factors on all North Dakota – Manitoba tie lines (G82R, L20D, and a conceptual Dorsey-Barnesville 500 kV line). Initial results from the Loop Flow Impact Study confirm that the Fargo Area Study Concept causes more total North Dakota – Manitoba loop flow than either the existing system or the Project. Figure 7.4H illustrates this disparity. The Western Plan (Fargo Area Study Concept) causes 5.5 percent more loop flow than the existing system, while the Eastern Plan (the Project, with an additional 345 kV build to accommodate the full 1,100 MW of incremental transfer capability required by the original Transmission Service Requests) increases loop flow by only 1.0 percent compared to the existing system. The transmission configurations compared in the Figure are those which the respective proponents claim can enable 1,100 MW of incremental Manitoba – United States transfers.

Figure 7.4H: Comparison of Total Loop Flow Impact

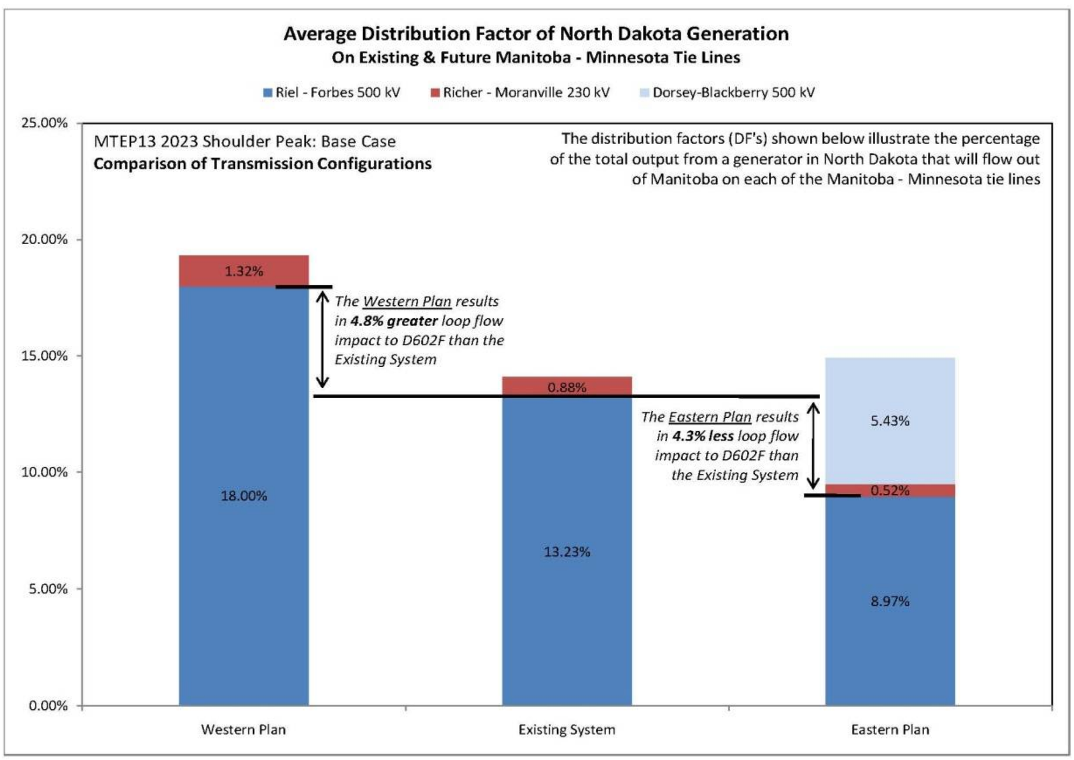


The second metric being used to evaluate the relative loop flow impact of each transmission configuration is the impact of loop flow on D602F loading. This metric is significant because, as discussed above, D602F is the main path that North Dakota –

Manitoba loop flow causes congestion on during times of high simultaneous Manitoba and North Dakota export. Upgrading D602F beyond its current maximum rating of 1,732 MW would be highly complex, and upgrading it beyond 2,165 MW would be technically infeasible, as discussed above. The impact of loop flow on D602F is measured by calculating the North Dakota generation distribution factor on the line. Initial results from the Loop Flow Impact Study confirm that the Fargo Area Study Concept would cause increased loading, and therefore increased congestion, on D602F due to loop flow while the Project actually relieves loading on D602F.

Figure 7.4I illustrates the difference in North Dakota generation distribution factors on D602F between the Western Plan (Fargo Area Study Concept), the existing system, and the Eastern Plan (the Project with the additional 345 kV build mentioned above). The Western Plan would cause 4.8 percent more loading on D602F due to North Dakota – Manitoba loop flow than the existing system, while the Eastern Plan will reduce loading on D602F due to loop flow by 4.3 percent compared to the existing system.

Figure 7.4I: Comparison of Loop Flow Impact on D602F

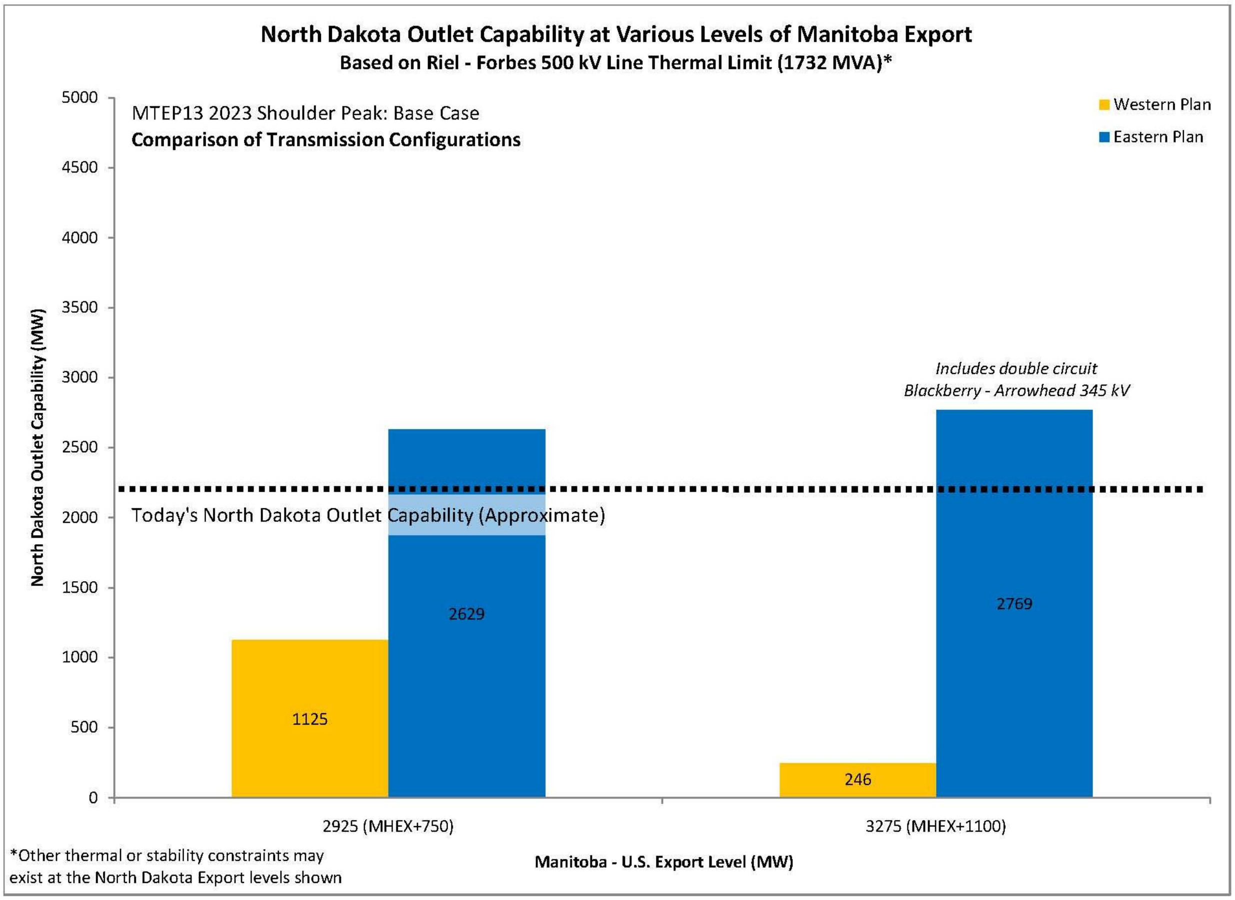


The third metric being used to evaluate the relative loop flow impact of each transmission configuration is the level of North Dakota outlet capability that can be achieved at the expected level of Manitoba export before the Roseau series capacitors on D602F are overloaded. This metric is a practical application of the first two, because it is a direct result of the total loop flow and the specific impact of loop flow on D602F loading. Using this metric will provide a good indication of the impact of the new tie line on regional generation outlet capability and overall system efficiency. The expected North Dakota outlet capability associated with a given transmission configuration will be determined by utilizing calculated distribution factors for proxy North Dakota and Manitoba generation to formulate an equation describing the relationship of increased power flows on the two interfaces.

While the Project is designed to facilitate 750 MW of incremental transfer capability from Manitoba to the United States (2,925 MW total), it can also be staged with a 345 kV build to the Duluth area to accommodate the incremental 1,100 MW of transfer capability (3,275 MW total) required by the original Transmission Service Requests, if the need arises. The Concept has been described as a single 500 kV build that can facilitate 1,100 MW of incremental Manitoba to United States transfers. Initial results from the Loop Flow Impact Study confirm that the Concept severely limits North Dakota outlet capability at both levels of increased Manitoba export if the Roseau series capacitors are not upgraded. The Project, on the other hand, maintains North Dakota outlet capability at or above today's levels simultaneous with the corresponding increase in Manitoba export capability, without requiring an expensive and complex upgrade of D602F.

Figure 7.4J compares the expected North Dakota outlet capability at MHEX levels of 2,925 MW and 3,275 MW for the Western Plan (Fargo Area Study Concept), which is the same configuration for incremental transfers of 750 MW and 1,100 MW, and the Eastern Plan (the Project), which requires additional 345 kV transmission to achieve 3,275 MW on MHEX. It is obvious that the Concept requires either an upgrade of the Roseau series capacitors or some other transmission project to mitigate heavy loading of D602F due to loop flow at either of the desired levels of Manitoba export capability.

Figure 7.4J: Comparison of North Dakota Outlet Capability at Expected MHEX Levels

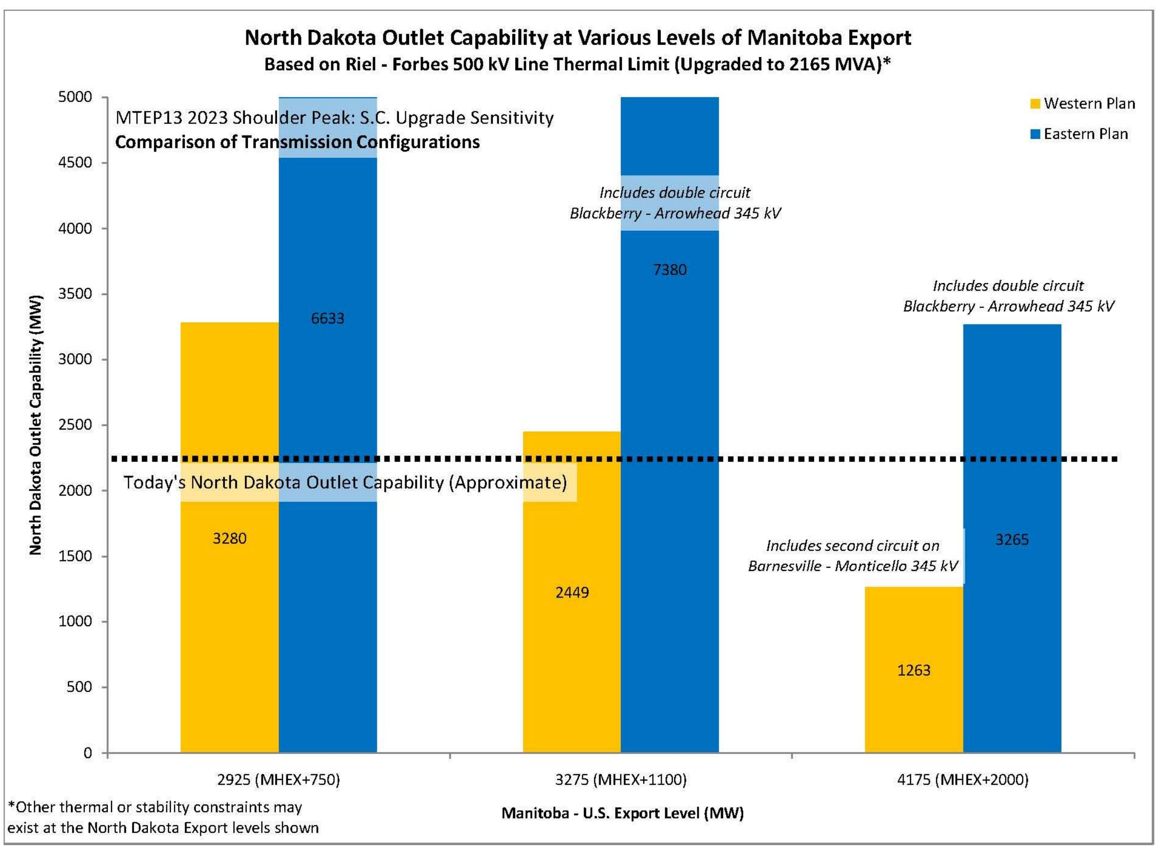


If the Roseau series capacitors are upgraded and the rating of D602F is increased to 2,165 MW, additional North Dakota outlet capability would be possible with both plans. However, initial results from the Loop Flow Impact Study confirm that the Concept would continue to be more limiting for North Dakota than the Project even after upgrading the Roseau series capacitors.

Figure 7.4K compares the theoretical North Dakota outlet capability at MHEX levels of 2,925 MW, 3,275 MW, and 4,175 MW (2,000 MW incremental) for the Western Plan (Fargo Area Study Concept) and the Eastern Plan (the Project with the additional 345 kV build mentioned above). A second 500/345 kV transformer at Barnesville and second circuit on the Barnesville – Monticello 345 kV line have been added for the Western Plan at the 4,175 MW Manitoba export level, as prescribed by the MANTEX studies.

The results clearly show that the long-term impact of the Concept would be to limit simultaneous North Dakota and Manitoba export capability by causing more North Dakota loop flow on D602F. Since the rating of D602F cannot be increased beyond 2,165 MW, it also becomes apparent that the Concept would not be able to facilitate 2,000 MW of increased Manitoba – United States transfers without significantly limiting North Dakota export capability due to loop flow. On the other hand, while there may be other thermal or stability constraints that need to be mitigated, increased loading on D602F due to loop flow is not a limiting issue for the Project. Even after enabling 2,000 MW of incremental Manitoba – United States transfers, the Project with the additional 345 kV build mentioned above would maintain North Dakota outlet capability at or above today's levels if the Roseau series capacitors are upgraded.

Figure 7.4K: Comparison of North Dakota Outlet Capability after Roseau Series Capacitor Upgrade



7.4.3.1.5. Implications of the Fargo Area Study Concept

The North Dakota – Manitoba loop flow phenomenon is a highly technical issue. The discussion above has focused on providing a high-level overview of the issue and how the Fargo Area Study Concept particularly would exacerbate the negative effects of North Dakota – Manitoba loop flow. In evaluating whether or not the Concept is a viable alternative to the Project, this section concludes with a discussion of the practical implications of the loop flow impact associated with the Fargo Area Study Concept, specifically with respect to the Concept's impacts on system upgrade requirements, regional generation outlet capability and transmission system expansion.

7.4.3.1.5.1. Additional System Upgrades

In contrast to the Project, additional system upgrades are needed for the Concept to enable the desired 750 MW of incremental Manitoba – United States transfer capability without limiting North Dakota outlet capability (see Figure 7.4J). While different studies have proposed different solutions, it is certain that the Concept would require system improvements to mitigate the negative effects of North Dakota – Manitoba loop flow that it inflicts. In the MANTEX studies, for example, it is assumed that the Roseau series capacitors can be upgraded, increasing the rating of D602F to accommodate more loop flow. Whether the cost associated with this upgrade is $11 million, as the MANTEX study report assumes[61], or whether it costs $30-50 million, as estimated by Manitoba Hydro[62], these are incremental upgrade costs that will not be required by the Project.

Several alternative system upgrades have also been considered in various studies to mitigate the loop flow problem associated with the Concept. These include installing the second circuit on the CapX2020 Bison (Barnesville) – Monticello 345 kV line that the Commission approved for future additional transfer capability and long term benefits, building a new Bison – Brookings 345 kV or 500 kV line, or installing a phase shifting transformer on G82R at the Glenboro Substation in Manitoba. With the possible exception of the G82R phase shifter, which may be required to facilitate the desired level of Manitoba Hydro import (i.e., MHEX flow north) for the Project, none of these upgrades will be required by the Project. Because it is a more efficient regional solution than the Concept, the Project has the advantage of reserving system upgrades that have a relatively minimal human and environmental impact, like the Roseau series capacitor upgrade and the second Bison – Monticello 345 kV circuit, for providing future outlet capability as it becomes necessary. The Concept, on the other hand, would require one or both of these upgrades just to maintain North Dakota outlet capability at today's levels. The fact that the Concept requires additional system upgrades to mitigate inefficiencies

[61] MANTEX Study, August 1, 2012, p. vii.
[62] White Paper on Series Capacitor Upgrade Issues.

caused by North Dakota – Manitoba loop flow and increased utilization of D602F demonstrates that the Concept is an inferior alternative to the Project.

7.4.3.1.5.2. Regional Generation Outlet Capability

While the MISO Wind Synergy Study has shown that both the Concept and the Project would enable optimized and economically beneficial wind-water "synergy" in a theoretical market environment, the planning studies discussed above demonstrate that the Concept would preclude high simultaneous production from both resource types because of its negative impact on North Dakota – Manitoba loop flow. In contrast, the Project will provide the desired wind-water synergy without restricting the operation of the system or the power market during times when high simultaneous output from North Dakota wind and Manitoba hydropower resources becomes desirable. In a world where the affordable integration of clean, renewable energy resources is becoming an increasingly significant issue, good system planning practices must take into account the long-term flexibility and efficiency of a large-scale regional transmission project for enabling or inhibiting the development of such resources. The fact that the Concept would cause continual conflict between high levels of North Dakota wind generation exports and high levels of Manitoba hydropower exports due to its negative effect on North Dakota – Manitoba loop flow, while the Project will enable simultaneous wind and hydro export levels well beyond today's levels with no limitations from loop flow, demonstrates that the Concept is an inferior alternative to the Project.

7.4.3.1.5.3. Transmission System Expansion

From a long-term transmission system planning perspective, the Concept is more likely than the Project to require large-scale transmission system expansion to enable additional power to be delivered from resource-rich areas in North Dakota and Manitoba to load centers on the Iron Range, in the Twin Cities, and further east and south. The original Manitoba Hydro TSRs called for 1,100 MW of incremental transfer capability from Manitoba to the United States. Recently, MISO Definitive Planning Phase ("DPP") generator interconnection study models have included North Dakota Export levels nearing 3,000 MW, approximately 1,000 MW beyond the studied outlet capability of the NDEX interface.

As shown in Figure 7.4L, if the Roseau series capacitors are upgraded, both the Project (Eastern Plan, with double circuit Blackberry – Arrowhead 345 kV) and the Concept (Western Plan, with the second Barnesville – Monticello 345 kV circuit) can facilitate the resulting simultaneous North Dakota and Manitoba export levels. However, any substantial increase in Manitoba – United States export capability beyond 3,275 MW will drive the North Dakota outlet capability associated with the Concept below the levels currently being contemplated in the MISO DPP studies. If a large enough increase in Manitoba – United States export is desired someday, North Dakota outlet capability will be driven well below existing levels, as shown by the MHEX+2000 scenario in Figure 7.4L. This is due to the loop flow impact of the Concept.

Figure 7.4L: Comparison of Long-Term Available Simultaneous Export Capability

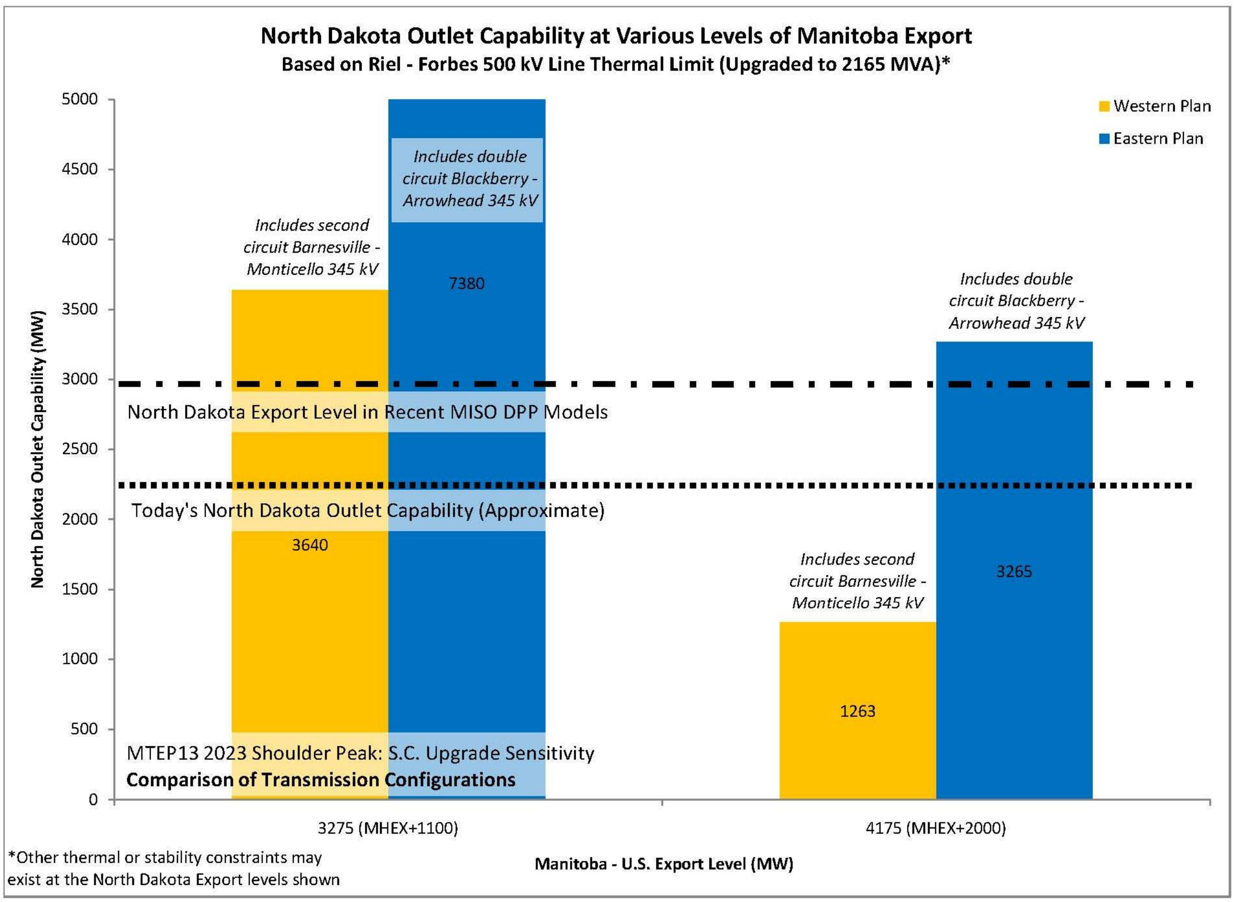


Figure 7.4L illustrates that, at some point, increased outlet capability from Manitoba, North Dakota, or both, may not be possible with the Concept apart from building another new Manitoba – United States tie line. While the Project would require an additional 345 kV line from the Iron Range to Duluth to achieve 3,275 MW of incremental Manitoba outlet capability and would potentially require some upgrades to achieve higher North

Dakota outlet capability or Manitoba outlet capability beyond 3,275 MW, it certainly does not appear that it would require another new tie line. Therefore, the negative impact that the Concept would have on North Dakota – Manitoba loop flow could mean the difference (long-term) between building or not building a third 500 kV Manitoba – United States tie line. The fact that the loop flow issues associated with the Concept would increase the likelihood of large-scale transmission expansion in the future, while the Project actually improves the loop flow situation, demonstrates that the Concept is an inferior alternative to the Project.

7.4.3.1.6. Fargo Area Study Concept Summary

The preceding discussion has focused on the background of the Fargo Area Study Concept and the North Dakota – Manitoba loop flow phenomenon, the impact that the Concept has on North Dakota – Manitoba loop flow, and the implications for regional generation outlet capability, system performance, and long-term transmission system planning. Minnesota Power, MISO, Manitoba Hydro, and other utilities have all given substantial consideration to the Concept. While the Concept exhibits similar performance and benefits in many study scenarios when compared to the Project, it can be shown that there are serious flaws with the Concept under some of the most stressed study scenarios. This is fundamentally because the Concept introduces a new low-impedance path between North Dakota and Manitoba, dramatically aggravating the well-documented North Dakota - Manitoba loop flow phenomenon. The resulting inefficiencies in the regional transmission system would constrain generation outlet capability for North Dakota, Manitoba, or both, potentially requiring transmission system upgrades that would not be required for the Project. Having thoroughly evaluated the Concept as an alternative to the Project, Minnesota Power has determined that the substantial negative impact it has on North Dakota – Manitoba loop flow is compelling and makes the Concept an inferior alternative to the Project.

Beyond the technical inferiorities of the Concept, it is highly improbable that it could meet Minnesota Power's contractual obligation of an in-service date of June 1, 2020. The Concept is already nearly one and one-half years behind the Project in the permitting and routing process and to date no utility has stepped forward to begin these efforts. Finally, it must be noted that despite the time, attention and analysis given this Fargo Area Study Concept by a variety of entities, to date no entity has indicated a willingness to develop and fund the construction of such a transmission line.

7.4.3.2. Shannon Substation Alternative

In the early stages of the Project, the existing Shannon Substation located near Chisholm, Minnesota, was considered as an endpoint for the proposed 500 kV line. During further engineering and siting review, it was determined by Minnesota Power that the Shannon Substation is an inferior long-term solution compared to the Blackberry Substation for several reasons. First, the Shannon Substation does not provide as much 230 kV outlet capability as the Blackberry Substation, and did not perform as well electrically as the Blackberry Substation in preliminary power flow studies. Second, the Shannon Substation is located adjacent to an active mine on property leased from the mine. Since the lease agreement for the Shannon Substation has an infrastructure relocation provision, there would be considerable risk in making significant new critical infrastructure investments on leased land. Therefore, the Shannon Substation endpoint is not a viable alternative to the Project.

7.4.3.3. Forbes Substation Alternative

The existing Forbes Substation located near Eveleth, Minnesota, was also considered as an endpoint for the proposed 500 kV line. Similar to the Shannon Substation, the Forbes Substation endpoint was found to have limited outlet capacity and inferior electrical performance compared to Blackberry. Additionally, the Forbes Substation is located south of the Iron Range formation in the midst of active mines. The most feasible locations for crossing the Iron Range formation appear to be further west, near Grand Rapids, meaning that a Forbes endpoint would likely increase the overall length of the routing options between Winnipeg and the Iron Range, thus increasing the overall human and environmental impact and cost of the Project. Therefore, the Forbes Substation endpoint is not a viable alternative to the Project.

7.4.4. Double Circuiting Existing Lines

Double circuiting is the construction of two separate circuits on the same structures. The only existing double circuit opportunities for the Project are two existing tie lines from Manitoba: the Richer – Moranville 230 kV line (R50M), which extends all the way to the Shannon 230 kV Substation on the Iron Range, and the Dorsey – Forbes 500 kV line (D602F), which extends all the way to the Forbes 500 kV Substation on the Iron Range. From a reliability perspective, double circuiting is typically avoided because a common structure failure could result in the loss of both lines. Double circuiting also creates maintenance constraints if only one line can be de-energized at a given time. Since both lines in this case would be tie lines between Manitoba and the United States, it would not be acceptable to de-energize both at the same time for maintenance purposes.

Furthermore, since double circuiting with an existing line is typically proposed as a method of limiting the proliferation of new transmission line corridors, it often requires an extended outage of the existing line to construct the new double circuit line in its place. Since an extended outage of one of the four existing Manitoba tie lines during the 48 months it will take to construct the Project would not be acceptable, the new double circuit line would have to be built adjacent to the existing line or in a completely new corridor to allow the existing line to stay in service during construction. Even though the existing transmission line corridor could eventually be retired if the new line was double circuited with an existing line, the fact that a new corridor would have to be developed significantly diminishes the value of double circuiting in the first place.

Since double circuiting the Project with one of the two existing Manitoba tie lines would increase the cost of the Project considerably without providing the benefit of fully utilizing an existing transmission line corridor, double circuiting is not a viable alternative for the Project.

7.4.5. DC Alternative

High voltage direct current ("HVDC") lines are sometimes proposed for transmitting large amounts of electricity over long distances. This is because the line losses associated with a long HVDC line are generally less than those associated with an AC line of the same length. While the loss savings associated with an HVDC line may be economically beneficial, HVDC lines also require expensive conversion stations at each delivery point because the DC power must be converted to AC power before it can be interconnected to the AC transmission system and delivered to customers. Given these benefits and costs of HVDC transmission, the break-even line length at which HVDC becomes economically feasible compared to AC transmission is usually between 400 and 500 miles. Since the total length of the Project plus its Canadian counterpart will be less than 400 miles, an HVDC alternative would not be economically justified.

Furthermore, Manitoba Hydro expressed concerns with an HVDC alternative early in the development of the Project. Manitoba Hydro's concerns stem from the technical risks associated with having multiple HVDC links in a common area. Currently, Manitoba Hydro operates two HVDC bipoles that connect their northern generation to the Winnipeg area, terminating at the Dorsey converter station. As mentioned in Section 7.4.1 above, Manitoba Hydro is also in the process of developing a third HVDC bipole, which will terminate at the Riel converter station near Winnipeg. If a fourth HVDC link were developed with a terminus in the Winnipeg area, the risk of control interaction or frequency response issues would be considerable. For example, three phase AC faults in the Winnipeg area could cause simultaneous commutation failure on all four bipoles, which could lead to load shedding. Due to the technical considerations expressed by Manitoba Hydro and the fact that HVDC is not economically justified by the distance of the Project and its Canadian counterpart, HVDC is not a feasible alternative to the Project.

7.4.6. Undergrounding

Undergrounding is an alternative that is rarely used for high voltage transmission lines. Until recently, there was not a single underground 500 kV line that had been built in the United States. One of the primary reasons underground high voltage transmission lines are seldom used is that they are significantly more expensive to engineer and construct than overhead lines. In addition, there are increased line losses and additional maintenance expenses incurred throughout the useful life of an underground high voltage line that further increase the total additional cost of building an underground line instead of an overhead line. Underground high voltage lines also present serious operating and maintenance challenges due to the relative inaccessibility of the underground conductors. Therefore, due to the construction, maintenance, reliability, and cost drawbacks of high voltage underground transmission lines, and the fact that there is limited experience in the United States with building an underground 500 kV transmission line, undergrounding is not a viable alternative for any segment of the Project.

7.5. The "No Build" Alternative

Before proposing a transmission or generation solution, Minnesota Power considered the viability of managing the existing system such that building additional facilities could be avoided. As discussed below, this "no build" alternative does not provide a viable alternative and would not achieve the benefits of the Project.

7.5.1. Conservation and Demand Side Management Efforts Cannot Replace the Need for the Project

Minnesota Power's Conservation Improvement Program (CIP) is integral part of its resource planning. CIP programs focus on increased efficiencies that reduce the amount of energy needed for certain uses. Minnesota Power's CIP includes residential, commercial, and small scale renewable programs. The Next Generation Energy Act of 2007 introduced, in addition to a minimum spending requirement of 1.5%, an energy-saving goal of 1.5% of gross annual retail electric energy sales by 2010. Since 2010 Minnesota Power has exceeded the 1.5% annual savings goal. While conservation is an important component of Minnesota Power's overall resource planning, it cannot eliminate the need for this Project to deliver at least 383 MW to Minnesota Power's customers as well as other load growth driving the need for the Project. Conservation programs will continue to be implemented by Minnesota Power to maximize efficient use of electricity; however, these programs cannot slow load growth sufficiently to mitigate the projected inadequacies in the transmission system that require delivery of an additional 750 MW from Manitoba to the United States. Minnesota Power's demand side management and conservation effort are further discussed in Appendix K.

7.5.2. Existing Facilities Cannot Meet the Need for Increased Transmission Between Manitoba and Minnesota and the Region

As discussed in Section 6.2.1, above, and as the Department and Commission recognized in the 938 Docket, the current transmission system cannot support the delivery of an additional 250 MW of power from Manitoba to the Minnesota Power service area. Likewise, the current transmission system also cannot support the additional 133 MW power sale and Renewable Optimization Agreements, now being finalized between Minnesota Power and Manitoba Hydro. The existing interface between Manitoba and the United States consists of three 230 kV lines and one 500 kV line. Not only are these facilities unable to accommodate increased transfer of energy from Manitoba into the United States, an unplanned outage of the lone existing 500 kV line is currently the largest single contingency in MISO. The Project will reduce loading on the existing tie lines and improve the performance of the transmission system during contingencies, benefitting the entire state and region, compared to the status quo.

7.5.3. The Construction, Operation, Maintenance and Mitigation Measures to be Utilized will Minimize the Impact of the Project Compared to a "No Build" Scenario

As discussed above, the "no build" alternative is not a viable means of meeting the needs identified for increased capacity and energy that will be met by the Commission approved 250 MW Agreements. In addition, the mitigation and other measures to be taken by Minnesota Power in the construction, operation and maintenance of the Project will minimize the Project's impact.

The Project would avoid impacts to most public facilities by avoiding towns and cities, airports, and telecommunication structures to the extent practicable. Likewise, most residences would be avoided by routing around developed or rural residential areas. In some instances, such as in highly populated areas like the Iron Range, avoidance of residences may not be feasible.

Residences, public facilities and communication structures will be avoided to the extent practicable. Landowners will be compensated for the necessary Project easements. Negotiations with land owners will be conducted in accord with state guidelines and will include information on eminent domain and Minn. Stat. § 216E.12.

The Project will require a 200-foot-wide right-of-way easement as it crosses agricultural lands. The easement will allow Minnesota Power to construct, operate and maintain the transmission line; the landowner will still retain the land for other compatible uses.

Vegetation management may be necessary to control weeds within the easement, especially around the structures where herbicide applications by the landowner may not be feasible. Interference with aerial spraying may also be of concern, especially for rice production and for large acreages that typically use crop dusters to apply herbicides and pesticides.

Minnesota Power will work with individual landowners on easement acquisition during final design of the transmission line. Discussions will cover construction and maintenance practices to control weeds and will include information on land acquisition options. The Project design will likely use self-supporting structures on tilled lands to minimize the impact of guy wires on farming activities.

Wetlands are present throughout the Project Area such that it will not be feasible to construct the Project without impacting wetlands. Two types of permanent impacts will likely occur – fill associated with installation of the structures and conversion from forested to non-forested wetland types. Temporary impacts may also occur during construction, when construction access across wetlands will be necessary.

Impacts to rivers and streams are anticipated to be minimal since the transmission line can span these systems. Tree clearing across trout streams may result in slight temperature impacts within the streams. The Project will avoid direct impacts to most lakes and open water areas. Some open waters may be spanned by the transmission line.

Minnesota Power will work with state and federal agencies to obtain the necessary wetland and water crossing permits. Mitigation will be developed in compliance with permit requirements. Typical mitigation may include: minimization of stream impacts by maintaining a buffer at the stream/water crossing, maintaining or planting shrubby vegetation at trout stream crossings, and wetland restoration or purchase of wetland bank credits to mitigate for unavoidable wetland impacts.

The Project has potential to impact sensitive state and federally listed species. Impacts would primarily be related to changes in habitat type through tree clearing, though direct impacts due to construction activities may also occur.

Impacts will be minimized by conducting surveys to identify species locations and avoiding to the extent practicable. Avoidance may include construction timing restrictions for some species (eagles and other listed sensitive birds) or shifting the location of the transmission line. Minnesota Power will work with state and federal agencies to identify appropriate mitigation for unavoidable impacts.

The Project is expected to have minimal impact on recreational resources. Some habitat changes within wildlife management areas will likely occur, however their recreational use for hunting will be maintained.

Minnesota Power will work with land managers to minimize impacts to wildlife management areas through the routing and siting process, and will obtain the necessary permits and approvals prior to beginning construction.

Construction of the Project on forested lands will require tree clearing. Landowners will be compensated for saleable timber. NERC standards require that the transmission lines have a certain amount of clearance from trees to minimize potential hazards that could impact the line. Thus, the easements across timber lands will remove these lands from future timber production.

The Project will likely cross parcels that have been put into a forest conservation reserve program that is managed by the state and property owner. Minnesota Power will work with the owner and state to minimize impacts during the siting and routing process, and will provide mitigation consistent with the forest conservation program requirements.

Landowners will be compensated for the easement and harvestable timber that is required for Project construction. In the long term, the easement will be managed consistent with NERC standards; trees considered a hazard will not be allowed under or adjacent to the line.

Selection of a route across the Iron Range will consider current and future mining activities. There is some potential that the route could be constructed over mineral resources, thereby limiting future extractions or requiring future mitigation.

Minnesota Power will work with the Department of Natural Resources ("DNR") Lands and Minerals during the siting and routing process to minimize impacts to current and future mining operations, and would give consideration to mineral ownership or mineral operating interest during the routing process.

The locations of cultural resources within the Project Area have not been determined because extensive surveys have not been completed. Prior to construction, field studies will be conducted to identify archaeological, architectural, and cultural resources within the selected route.

Finally, the Project will avoid impacts to known archaeological and cultural resources, to the extent practicable. For sites that cannot be avoided, Minnesota Power will develop mitigation plans under consultation with state and federal agencies, as well as tribal authorities. Minnesota Power intends to work with the DOE to develop a Programmatic Agreement that will identify cultural resource evaluation and mitigation procedures.

8. SUMMARY

8.1. Denial Would Adversely Affect Minnesota Power, its Customers, the State and the Region

Through Minnesota power's 2010 Integrated Resource Plan, the 938 Docket and the 2013 Integrated Resource Plan, the Commission has thoroughly reviewed Minnesota Power's need for and the benefits of the 250 MW of hydropower provided by the 250 MW Agreements. Indeed, in the 938 Docket, the Commission found both that the hydropower resources proposed in the 250 MW Agreements are the most appropriate resources to meet the Company's needs over the period 2020 through 2035 and that the 250 MW Agreements are in the public interest. At the same time, the Commission recognized that new transmission facilities were required to deliver these positive results to Minnesota Power's customers. Denial of the Project not only forfeits these benefits and adversely impacts the Company and its customers, it also forecloses the benefits of the additional 133 MW Renewable Optimization Agreements.

In addition, denial of a Certificate of Need for the Project would impact the State and the region. The Project provides a necessary additional interconnection between the United States and Manitoba at a time when Manitoba Hydro plans to add significant hydroelectric capacity to its system. The Project can provide other utilities access to these carbon-free resources, while also increasing the reliability of the transmission system as a whole. Moreover, the Project can facilitate even greater additions of wind energy to the system, with the attendant benefits identified in the Manitoba Hydro Wind Synergy Study. With no more feasible and prudent alternative, denial of the Certificate of Need would have adverse impacts beyond those to Minnesota Power and its customers.

8.2. No More Reasonable and Prudent Alternative Has Been Demonstrated

The Project provides the appropriate means of addressing the need for new transmission infrastructure between Manitoba and the United States. When the Commission considered the 250 MW Agreements between Minnesota Power and Manitoba Hydro, it analyzed the following question: "Do the resources proposed in the PPA represent the most appropriate resources to meet [Minnesota Power's] resource needs over the period 2020 through 2035?" The Commission answered in the affirmative and also recognized the need for new transmission facilities to make delivery of the power possible. No changes have occurred since the Commission's February 1, 2012 Order in the 938 Docket that yield a different result.

In this Application, Minnesota Power has analyzed various alternatives to the Project, including: (1) a "no-build" alternative; (2) other generation alternatives, including distributed generation; and (3) various transmission system alternatives, including various size lines, various terminal points, and upgrades of existing facilities. No alternative considered more reasonably or prudently meets the need for increased transmission capabilities to serve Minnesota Power, its customers and the region than the Project.

Moreover, denial of a Certificate of Need for the Project would severely impact Minnesota Power and its customers, as the Company would be unable to effectuate the Commission-approved 250 MW Agreements with Manitoba Hydro and would be unable to deliver these needed resources to its customers, denying them the environmental, economic and reliability benefits the 250 MW Agreements and the 133 MW Renewable Optimization Agreements together will provide. Denial of a Certificate of Need would also harm the State and the region, through the loss of wind-hydro synergies, the loss of the ability to access additional hydropower resources, and the loss of increased regional reliability by addressing the need for an additional tie line between Manitoba and the United States.

8.3. The Project will Protect the Environment and Provide Benefits to Minnesota Power's Customers, the State and the Region

The Project represents the next important step in Minnesota Power's Energy***Forward*** resource strategy, designed to supply its customers with a safe, reliable, and affordable power supply while reducing the Company's use of coal-fired resources, diversifying its supply portfolio and successfully integrating significant additions of wind and other renewable energy resources. These efforts will lead to lower emissions, benefitting the environment and allowing Minnesota Power to better manage risk associated with any future federal or state air quality regulations.

Minnesota Power has already solicited substantial stakeholder and public input regarding the Project and performed substantial analysis regarding alternative routes. Through these efforts, the Company has identified route corridors for the Project that allow optimum performance of the proposed transmission line, while minimizing the impacts to social, economic and environmental resources. As permitting processes move forward, Minnesota Power will continue to receive public, landowner, agency and other stakeholder input, as well as field survey and additional analysis, to determine the final route alternatives that will be presented to the Commission.

In addition, the Project will provide substantial economic benefits to northern Minnesota and the region. The Project will create over 200 construction jobs and generate significant tax revenues, stimulate increased business for hotels, restaurants, and other services along the final route, and have other indirect benefits estimated to total approximately $850 million in northern Minnesota. While providing these benefits, the Project also ensures a reliable supply of power to an area poised for significant economic growth.

8.4. The Project will Comply With all Applicable Federal, State and Local Requirements

Minnesota Power identifies the other permits, approvals and consultations that may be required for the Project in Section 3.5. Sections 5.2 through 5.4 detail the acquisition, construction, operation and maintenance associated with the Project and the attendant requirements for those processes. Minnesota Power is committed to complying with all of these requirements and has already engaged in significant agency consultation on these issues in furtherance of that commitment.

8.5. Conclusion

For all of the reasons set forth in this Application and as supported by the Appendices hereto, Minnesota Power respectfully requests the Commission issue a Certificate of Need authorizing construction of the Great Northern Transmission Line, an approximately 240 mile 500 kV transmission line between the United States-Canada border and the Blackberry Substation in Itasca County, Minnesota.

8427532v1