**BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS**
**600 NORTH ROBERT STREET**
**ST. PAUL, MINNESOTA 55101**

**FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION**
**SUITE 350**
**121 SEVENTH PLACE EAST**
**ST. PAUL, MINNESOTA 55101-2147**

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| Beverly Jones Heydinger | Chair |
| David C. Boyd | Commissioner |
| Nancy Lange | Commissioner |
| Dan Lipschultz | Commissioner |
| Betsy Wergin | Commissioner |

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| IN THE MATTER OF THE REQUEST OF MINNESOTA POWER FOR A CERTIFICATE OF NEED FOR THE GREAT NORTHERN TRANSMISSION LINE PROJECT | OAH Docket No. 65-2500-31196<br>MPUC Docket No. E015/CN-12-1163 |

# INITIAL BRIEF OF THE MINNESOTA DEPARTMENT OF COMMERCE

**December 19, 2014**

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## INTRODUCTION

The Minnesota Department of Commerce, Division of Energy Resources ("Department" or "DOC") respectfully submits this Initial Brief in order to provide the Administrative Law Judge ("ALJ") and the Minnesota Public Utilities Commission ("Commission") with analysis of the facts and law pertaining to the request for a Certificate of Need ("CN") for the Great Northern Transmission Line (the proposed "Project" or "GNTL"), filed by Minnesota Power ("MP" or "Applicant" or "Company"). Through its analysis of the record, the Department concludes that MP has met its burden of demonstrating that the proposed Project is needed under Minn. Stat. § 216B.243 (2014) and Minnesota Rules 7849.0120 (2013). There are not any unresolved issues between DOC and MP at this time.

## PROCEDURAL HISTORY

This matter initially began when the Applicant filed a Notice Plan Petition for the GNTL on October 29, 2012. The Department reviewed the Notice Plan Petition and on November 19, 2012, while concluding that much of the Notice Plan was reasonable, recommended that MP provide additional detail regarding how its Notice Plan would be impacted by certain Midcontinent Independent System Operator, Inc. ("MISO") studies and how MP would accomplish requisite notification of tribal governments, town governments, statutory cities, home rule charter cities, and certain counties that would be affected by the proposed Project. On December 10, 2012, MP provided additional detail for its Notice Plan, which satisfied the Department's concerns, as reflected in a January 23, 2013 letter to the Commission.

On November 20, 2012, MP submitted a Petition for Exemption from or Confirmation of Certain Filing Requirements Regarding the Great Northern Transmission Line ("Exemption Petition"). On December 17, 2012, the Department filed Comments in which it recommended approval of some of MP's requests and denial of others. On January 16, 2013, MP filed Reply

Comments in which it largely agreed with the Department, except with regard to two exemption requests. The Department and MP resolved the two exemption requests, as reflected in the Department's January 23, 2013 letter to the Commission. In addition, the Department recommended and MP agreed that only one of MP's exemption requests be denied, which dealt with system capacity data under Minnesota Rules part 7849.0280(I).

On February 28, 2013, the Commission issued an Order Approving Notice Plan, Granting Variance Request, and Approving Exemption Request.

On October 21, 2013, MP filed an Application for a Certificate of Need ("Application") for the GNTL, a 500 kilovolt ("kV") high-voltage transmission line.[1] The proposed Project primarily involves construction of a 500 kV transmission line from the international border in Minnesota to a substation near Blackberry, Minnesota (the "Blackberry Substation"). MP proposes to complete the project in partnership with Manitoba Hydro, a Crown Corporation ("MH") based in Winnipeg, Manitoba. The proposed Project's primary objective is to provide better access to Manitoba Hydro's hydropower generation stations. In addition, MP stated that the proposed Project would facilitate storage of wind power. Overall, MP stated that the proposed Project is designed to deliver 383 megawatts ("MW") of hydropower and wind storage energy products to MP's customers.

On November 19 and 21, 2013, the Department filed Comments on the completeness of the Application. The Department reviewed the Application and determined that the Application

[1] The Notice Plan Petition initially included a 345 kV transmission segment from the Blackberry Substation to the Arrowhead Substation, but MP's Application notes that it dropped this proposal because "[a]t this time there are not sufficient transmission service requests to the support this second 345 kV phase." MP Ex. 9 at 2 (Petition).

was substantially complete. The Department recommended that the Commission refer this matter to the Office of Administrative Hearings ("OAH") for a contested case proceeding.

On November 19, 2013, the Large Power Intervenors ("LPI") filed Comments recommending that this matter be referred to OAH for a contested case proceeding.

On November 19, 2013, Carol Overland with Legalectric, Inc. (who would later represent Residents and Ratepayers Against the Not-So-Great Northern Transmission ("RRANT")) filed Comments recommending that this matter be referred to OAH for a contested case proceeding.

On December 3, 2013, MP filed Reply Comments requesting that the Commission declare the Application substantially complete and noted its agreement that this matter should be referred to OAH for a contested case proceeding.

On January 8, 2013, the Commission issued an Order Accepting Filing, Varying Time Lines, and Notice and Order for Hearing. In this Order, the Commission deemed MP's Application substantially complete and referred the matter to OAH for a contested case proceeding. In addition, the Commission varied the forty-day timeline for holding a public meeting in conjunction with the Commissioner of the Minnesota Department of Commerce's requirement that it prepare an environmental report in this matter.

On January 17, 2014, the ALJ assigned to this matter, Ann C. O'Reilly, held a prehearing conference.

On January 29, 2014, ALJ O'Reilly issued a First Prehearing Order setting procedures for parties in the case and establishing the following schedule:

**Environmental Report**

| Milestone | Timing |
|---|---|
| Notice of ER Scoping Meetings | January 15, 2014 |
| ER Scoping Meetings | February 11, 12, 13, 18, 19, 20, 2014 |

| | |
|---|---|
| ER Scoping Comment Period Ends | March 14, 2014 |
| Scoping Decision Released | March 28, 2014 |
| ER Released | June 30, 2014 |

**Certificate of Need**

| Milestone | Timing |
|---|---|
| MP Direct Testimony | August 10, 2014 |
| Deadline for Intervention | August 29, 2014 |
| Other Parties' Direct Testimony | September 19, 2014 |
| Public Hearings | Weeks of October 6 and 13, 2014 |
| All Parties' Rebuttal Testimony | October 24, 2014 |
| All Parties' Surrebuttal Testimony | November 7, 2014 |
| Transcripts of Public Hearings to be Filed and Made Available to the Public | November 7, 2014 |
| Evidentiary Hearing | November 12-14, 17-19, 2014 |
| Public Comment Period Closes | December 2, 2014 |
| OAH to File All Received Comments; Transcript of Contested Hearing to be Filed and Made Available to the Public | December 4, 2014 |
| Issues Matrix Due[2] | December 5, 2014 |
| Initial Briefs Due; Applicant's Proposed Findings Due | December 19, 2014 |
| Reply Briefs Due; Other Parties' Proposed Findings Due | January 16, 2015 |
| ALJ's Report Due | March 16, 2015 |

The ALJ also granted intervention petitions of RRANT and LPI.

On April 22, 2014, the Department issued its Environmental Report Scoping Decision.

[2] This deadline was added by the ALJ at the close of the evidentiary hearing.

On July 14, 2014, the Department's Energy Environmental Review and Analysis Division ("DOC-EERA") filed its Environmental Report ("ER") in this CN matter as required by Minnesota Rules 7849.1500, subparts 1 and 3.

On August 8, 2014, MP filed the direct testimony of David J. McMillan regarding overview of the CN filing and of the Project, the direct testimony of Michael H. Donahue regarding the cost of the Project, the direct testimony of Allan S. Rudeck, Jr. regarding Project need and non-transmission alternatives, the direct testimony of Christian Winter regarding Project description and transmission alternatives, the direct testimony of James B. Atkinson regarding stakeholder involvement, environmental data, and regulatory requirements, and the direct testimony of Scott Hoberg regarding MISO studies.

On August 15, 2014, RRANT filed Comments on the ER Scoping Decision.

On September 19, 2014, the Department filed the direct testimony of Sachin Shah regarding need for the proposed Project under Minn. R. 7849.0120(A)(1) and the direct testimony of Dr. Stephen Rakow regarding overall need for the proposed Project under Minn. R. 7849.0120(A)(2) to (4) and the Department's analysis of alternatives and policy under Minn. R. 7849.0120(B)(1) to (3).

On September 19, 2014, LPI filed the direct testimony of Lane Kollen regarding costs of the proposed Project and recovery of such costs from retail customers.

On October 24, 2014, MP filed the rebuttal testimony of David J. McMillan and the rebuttal testimony of Michael H. Donahue.

On October 24, 2014, the Department filed the rebuttal testimony of Dr. Stephen Rakow.

On November 6, 2014, the ALJ granted the Department's motion for Sachin Shah to appear by telephone at the evidentiary hearing.

On November 7, 2014, LPI filed the surrebuttal testimony of Lane Kollen.

On November 7, 2014, MP filed the surrebuttal testimony of Allan S. Rudeck, Jr. and the surrebuttal testimony of David J. McMillan.

On November 7, 2014, the Department filed the surrebuttal testimony of Mark Johnson and the surrebuttal testimony of Dr. Stephen Rakow.

On November 10, 2014, the Department filed an errata sheet to the surrebuttal testimony of Dr. Stephen Rakow.

RRANT did not file any testimony in this matter.

On November 12 and 14, 2014, the ALJ held an evidentiary hearing at the Commission.

## STATEMENT OF THE ISSUES

The main issue before the Commission is whether MP has shown that the proposed Project satisfies the applicable statutory and rule criteria for a CN, or whether a more reasonable and prudent alternative to the proposed Project has been demonstrated. The Department recommends that the Commission approve MP's Application for a CN because the Department concludes that MP has met its burden of demonstrating that the proposed Project is needed under the need criteria found in Minnesota Rules part 7849.0120 (2013). Also at issue is whether certain cost recovery, financial, and rate design issues should be dealt with in this proceeding.

## BURDEN OF PROOF

MP bears the burden of proof by a preponderance of the evidence that it has satisfied Minnesota legal criteria for issuance of a CN. Minn. Stat. § 243B.243, subd. 3 (2014); Minn. R. 7849.0120.

## ANALYSIS

### I. MP HAS SATISFIED THE LEGAL CRITERIA FOR A CERTIFICATE OF NEED UNDER MINN. STAT. § 216B.243 AND MINN. R. 7849.0120

The principal requirements for a CN are set forth in Minnesota Statutes section 216B.243, subdivision 3 and Minnesota Rules parts 7849.0120A–D. Essentially, Minnesota law requires MP to demonstrate that the proposed Project is needed and the rule requires that "a more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record . . . ." *See* Minn. Stat. § 243B.243, subd. 3; Minn. R. 7849.0120(B). As discussed further below, the Department concludes that MP has met these legal requirements.

Because of the nature of the proposed Project, MP needs a CN from the Commission. Facilities with a length greater than 1,500 feet and a capacity greater than 200 kV qualify as a large energy facility ("LEF"). Minn. Stat. § 216B.2421, subd. 2(2). Facilities with a capacity greater than 100 kV that cross a state border qualify as a LEF. *Id.* at subd. 2(3). Minnesota Statutes section 216B.243, subdivision 2 requires that LEFs must obtain a CN before siting or construction. Because the proposed GNTL is greater than 200 kV, is longer than 1,500 feet, and crosses a state border, the proposed GNTL requires a CN. DOC Ex. 53 at 12 (Rakow Direct).

Given that Minnesota Rules, where provided, are more detailed than corresponding statutory need criteria, the rule criteria found in Minnesota Rules part 7849.0120 are used in the Department's Initial Brief as a framework for evaluating MP's compliance with the legal criteria.

#### A. Summary of the Proposed Project

##### 1. Proposed United States and Canadian Facilities

There are three main aspects to MP's proposed Project in Minnesota. MP proposes to construct a new 500 kV transmission line from the United States/Canadian border to MP's

Blackberry Substation near Grand Rapids, Minnesota—approximately 235 to 270 miles depending upon the route selected. *See* MP Ex. 9 at 24 (Petition). In addition, MP proposes to install 500 kV series compensation (the preferred location is at the midpoint of the 500 kV line between the Dorsey and Blackberry substations)[3] and expand the existing Blackberry 230/115 kV substation to accommodate the 500 kV line, 500/230 kV transformation, and all associated 500 kV and 230 kV equipment. *Id.* MP states that the proposed GNTL is now estimated to cost between $557.9 million and $710.1 million (2013 dollars).[4] MP Ex. 38 at 5 (Donahue Direct). The proposed in-service date for the proposed GNTL is June 1, 2020. *Id.* at 2.

The proposed Project is planned to be built in conjunction with related transmission facilities in Canada. MH is the Canadian entity that has proposed these facilities. These facilities include: 1) a new 500 kV transmission line in southeastern Manitoba from the Dorsey Converter Station[5] to the United States/Canadian border–approximately 95 to 130 miles depending upon the route selected; 2) upgrades to the Riel[6] and Dorsey converter stations; and 3) modifications to the Glenboro substation. MP Ex. 41 at Schedule 3 at 31 (Hoberg Direct); MP Ex. 9 at 24 (Petition). After completion, the proposed GNTL is proposed to be maintained by MP. MP Ex. 9 at 16 (Petition). Operation of the proposed GNTL, however, would be turned over to MISO. *Id.*

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[3] *See* the MP Ex. 42 at 7 (Winter Direct), which describes "compensation" as including "the 500 kV series capacitor banks necessary for the reliable operation and optimal performance of the Project, and all associated 500 kV equipment."

[4] *See* the Company's response to Department Information Request No. 23 for the dollar units. DOC Ex. 53 at SR-4 (Rakow Direct Attachments).

[5] MH's Dorsey Converter Station, (located in Rosser, approximately 10 miles northwest of Winnipeg, Manitoba) is the southern terminus for MH's high voltage direct current ("HVDC") transmission lines known as Bipole I and Bipole II.

[6] The Riel Converter Station (located east of Winnipeg, Manitoba) is the southern terminus for MH's Bipole III HVDC transmission line, currently under construction.

According to MP, the proposed GNTL is designed to address the following needs (which are discussed in more detail below):

- To deliver the power called for under:
  - The Commission-approved *250 MW System Power Sale Agreement*[7] ("SPSA" or "PPA") and *Energy Exchange Agreement*[8] ("EEA") between MP and MH; and
  - The 133 MW Renewable Optimization Agreement ("ROA").[9]
- State and regional needs:
  - delivery of the power called for in other power purchase agreements that MH is pursuing;
  - provision of economic benefits to the entire MISO footprint; and
  - provision of reliability benefits during outages of the existing 500 kV line between Manitoba and Minnesota.

In addition to the new transmission facilities, MH has proposed new generation facilities that are related to the proposed GNTL. MH started construction of the new 695 MW Keeyask

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[7] The SPSA requires MP to purchase 250 MW of capacity and energy; MP's petition in Docket No. E015/M-11-938 indicates that the energy is purchased 16 hours per day, 7 days per week. The Petition at 100 indicates that the SPSA and EEA are for the period 2020 through 2035.

[8] MP's petition in Docket No. E015/M-11-938 indicates that the EEA would allow MP 250 GWh per year of annual energy storage. Note that 1,000 GWh per year total minus 750 GWh per year (from the ROA) leaves 250 GWh per year from the EEA. MP Ex. 43 at 16–17 (Rudeck Direct).

[9] The ROA, which MP did not file until the day before the due date for surrebuttal testimony in this proceeding, includes a proposed additional 750 GWh of annual "wind storage credit." MP Ex. 43 at 16–17 (Rudeck Direct). The Department notes that the ROA is currently under review in Docket No. E015/M-14-960.

generating station on July 16, 2014.[10] Keeyask's first unit is scheduled to be on-line in 2019. MP Ex. 9 at 4 (Petition). Keeyask is needed, in part, to supply the power for MP's agreements with MH. *Id.* at 70. The construction of the Keeyask generating station would result in MH having significant surpluses of firm energy.[11] DOC Ex. 53 at 4 (Rakow Direct). MH can either lock in sales of that surplus energy through contracts with utilities (such as the contract with MP) or sell the energy into short term markets such as MISO's energy market. *Id.* MH plans its system so that the system is capable of supplying sufficient dependable energy to meet firm energy requirements in the event of a repeat of the lowest historic hydraulic system inflow conditions. *Id.* Firm energy requirements are measured by forecasted requirements in Manitoba and existing export contracts. *Id.* Thus, even if MH does not have firm contracts for export, there is non-firm energy that is also available for export in most years—years where the system is not experiencing low water levels.[12] *Id.* Therefore the line might be used for non-firm energy sales even if there are insufficient firm energy sales.[13] *Id.*

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[10]*See* Manitoba Hydro, Keeyask Project Description, https://www.hydro.mb.ca/projects/keeyask/index.shtml?WT.mc_id=2613 (last visited Dec. 11, 2014).

[11] For MH's estimated energy sources and requirements from MH's proposed development plan as filed in MH's regulatory process, see pages 22, 26, 30, 34, etc. in the following file: NFAT 2013 Update DSM Sensitivities, Appendix 4.2: Manitoba Hydro Supply and Demand Tables (2013), http://www.hydro.mb.ca/projects/development_plan/bc_documents/appendix_04_2_manitoba_hydro_supply_and_demand_tables.pdf.

[12] For a discussion of MH's energy planning criteria see page 5 of the following file: Needs for and Alternatives To, Appendix 4.1 – Manitoba Hydro Generation Planning Criteria (2013), http://www.hydro.mb.ca/projects/development_plan/bc_documents/appendix_04_1_generation_planning_criteria.pdf.

[13] MH is paying a significant share of the costs for MP's proposed GNTL and is responsible for the portion of the line in Manitoba. Thus, MH has an incentive to find PPAs to recover their sunk transmission and generation costs. Further, the lack of firm contracts is one reason the Manitoba Public Utilities Board recommended (and the Manitoba government agreed) to delay the in-service date of the proposed Conawapa dam until additional contracts were in hand. *See Province Releases Public Utilities Board Report on Manitoba Hydro's Preferred Development*
(Footnote Continued on Next Page)

The proposed GNTL is also included in regional and state planning processes. DOC Ex. 53 at 14 (Rakow Direct). On the regional stage, MISO's process results in an annual report, the *MISO Transmission Expansion Plan* ("MTEP"). *Id.* In the current version of MTEP ("MTEP14"), the proposed GNTL is targeted for Appendix B.[14] *Id.* The current draft of MTEP14 defines projects in Appendix B as follows:

> Projects in Appendix B have been analyzed to ensure they effectively address one or more documented transmission issues. In general, MTEP Appendix B contains projects still in the Transmission Owners' planning processes or still in the MISO review and recommendation process. Appendix B may contain multiple solutions to a common set of transmission issues. Projects in Appendix B are not yet recommended or approved by MISO, so they are not evaluated for cost sharing. Any designation of project type (Baseline Reliability Projects, Market Efficiency Projects or Multi-Value Projects) for projects in Appendix B are preliminary. Thus, while some projects may eventually become eligible for cost-sharing, the target date does not require a final recommendation for the current MTEP cycle. The project will likely be held in Appendix B until the review process is complete and the project is moved to Appendix A.

*Id.* On November 25, 2014, the Federal Energy Regulatory Commission ("FERC") issued an *Order on Facilities Construction Agreement* where FERC accepted an executed Facilities Construction Agreement ("FCA"), which was entered into by MISO, MP, and MH. MP Ex. 64 (FERC Order). As the name indicates, the FCA regards construction of the proposed GNTL, in addition to issues of ownership and capital contribution among the parties to the agreement. *Id.*

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(Footnote Continued from Previous Page)
*Plan*, Manitoba, July 2, 2014, http://news.gov.mb.ca/news/index.html?item=31611&posted=2014-07-02.

[14] Further details are available at MISO, MTEP14, https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEP14.aspx.

Because FERC has approved the FCA, MP anticipates that MISO will move the proposed GNTL to Appendix A of MTEP14. *Id.*

As indicated, the proposed GNTL is also a part of Minnesota transmission planning. The state's transmission planning process involves a filing every two years by every transmission owner in Minnesota with the Commission. DOC Ex. 53 at 14 (Rakow Direct). The most recent plan included the proposed GNTL under tracking number 2013-NE-N13.[15] *Id.*

### 2. Ownership of the Proposed GNTL

MP, in partnership with MH, proposes to construct the GNTL. At this time, MP proposes to have majority ownership (51%) of the proposed GNTL. MP Ex. 34 at 13–14 (McMillan Direct). The remaining 49% of the proposed GNTL would be owned by a subsidiary of MH. *Id.* MH may transfer all or a portion of its share of the proposed GNTL, however, to another party. *Id.* at 14. Such potential future changes in ownership do not need to be addressed at this time. DOC Ex. 53 at 5–6 (Rakow Direct); Minn. R. 7849.0400 (2013). If the Commission approves the proposed CN, however, MP would need to file a petition with the Commission if there are material changes in ownership, according to Minnesota Rules part 7849.0400, subpart 2(H).

There is, however, a distinction between ownership, financial responsibility to invest, and rate recovery. While MP would own 51% of the proposed GNTL, MP would be responsible for funding only 46% of the construction costs. MP Ex. 38 at 9 (Donahue Direct). Under the proposal, MP would receive the difference (51% minus 46%) from MH via a Contribution in Aid of Construction ("CIAC").[16] *Id.* MP witness Mr. McMillan clarified that MP's customers would

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[15] Further details are available at Minnesota Electric Transmission Planning, Transmission Projects Report 2013, http://www.minnelectrans.com/report-2013.html.

[16] This issue is covered in the *Facilities Construction Agreement*. *See* MP Ex. 38 at MD, Schedule 5 at 2 (Donahue Direct).

be financially responsible for only 28.3% of the Company's revenue requirements related to the investment.[17] MP's remaining revenue requirements related to the investment (51% minus 5% CIAC less 28.3% ratepayers) are proposed to be paid by MH via a "Monthly Must Take Fee" contained in the terms of a 133 MW ROA,[18] which MP recently filed for approval by the Commission. A later section of this Initial Brief discusses the approval of the 133 MW ROA, which consists of the Energy Sale Agreement ("ESA") and a second EEA, as a condition to granting a CN for the proposed GNTL.

The energy proposed to be brought from Manitoba via the proposed GNTL would be part of U.S. imports from Canada. DOC Ex. 53 at 8 (Rakow Direct). Reports available at Canada's National Energy Board show that, between 2005 and 2013, MH was a net exporter of energy to Minnesota and North Dakota to a significant degree, exporting between 8.0 million and 11.5 million MWh annually (net of MH's imports from Minnesota and North Dakota). *Id.* MP estimated that the SPSA, EEA, and ROA are expected to provide over 1.5 million MWh annually to MP starting in 2020. MP Ex. 9 at 3 (Petition). At that time, the annual electric consumption by consumers on MP's system is forecasted to be about 10.4 million MWh. *See id.* at Appendix H at 85. Thus, MP estimated that the percent of MP's energy requirements supplied by MH would be about 14.4 percent in 2020. *Id.*; DOC Ex. 53 at 10 (Rakow Direct).

[17] The 250 MW for MP's PPA, divided by the 883 MW transfer capability of the proposed GNTL, equals 28.3%; thus, ratepayers would pay for the share of the line that they are using—assuming that no other costs flow through to ratepayers.

[18] A copy of the ROA is included as MP Ex. 43 at AJR, Schedule 2 (Rudeck Direct). *See also* MP's response to Large Power Intervenors' Information Request No. 28. DOC Ex. 54 at SR-4 (Rakow Direct Trade Secret Attachments).

### B. Under Minn. R. 7849.0120(A), MP Has Shown that the Probable Result of Denial Would Adversely Affect the Future Adequacy, Reliability, or Efficiency of Energy Supply to the Applicant, to the Applicant's Customers, or to the People of Minnesota and Neighboring States

After review of MP's Application and its Direct Testimony, the Department concluded that MP satisfied Minnesota Rules part 7849.0120(A). In evaluating a CN application, the rule directs consideration of the following factors:

> 1) the accuracy of the applicant's forecast of demand for the type of energy that would be supplied by the proposed facility;
>
> 2) the effects of the applicant's existing or expected conservation programs and state and federal conservation programs;
>
> 3) the effects of promotional practices of the applicant that may have given rise to the increase in energy demand, particularly promotional practices which have occurred since 1974;
>
> 4) the ability of current facilities and planned facilities not requiring certificates of need to meet the future demand; and
>
> 5) the effect of the proposed facility, or a suitable modification thereof, in making efficient use of resources.[19]

Minn. R. 7849.0120(A)(1)–(5). The accuracy of the applicant's forecast of demand for the type of energy is addressed first.

#### 1. Minn. Stat. § 216B.243, subd. 3(1) and Minn. R. 7849.0120(A)(1): Accuracy of the Applicant's Forecast of Energy Demand

Assessing need for the GNTL largely begins in MP's Power Purchase Agreement ("PPA") with MH for 250 MW in Docket No. E015/M-11-938 (the "11-938 Docket"). In that matter, MP petitioned for Commission approval of a 250 MW System Power Sale Agreement ("SPSA")[20] and an Energy Exchange Agreement ("EEA") between MP and MH. MP's 250 MW PPA was born out of the Company's 2009 Integrated Resource Plan ("IRP") in Docket No.

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[19] The Department did not directly address this criterion.
[20] The SPSA is commonly referred to a PPA and the terms are used interchangeably.

E015/RP-09-1088 (the "09-1088 Docket") where MP identified a capacity need beginning in 2013.

In the 11-938 Docket, the Department evaluated MP's proposed needs for additional capacity and concluded that "proposed needs for additional capacity and energy over the contract period (2020 through 2035) is supported by its updated demand and energy forecast." *In the Matter of Minnesota Power's Request for Approval of a Power Purchase Agreement with Manitoba Hydro Company*, Docket No. E015/M-11-938, Department Comments at 3 (Nov. 18, 2011). At issue in the 11-938 Docket were the following questions: 1) "Do the resources proposed in the PPA represent the most appropriate resources to meet MP's resource needs over the period 2020 through 2035?" and 2) "If the resources proposed in the PPA are the most appropriate resources, is the proposed PPA in the public interest?" *Id.* After extensive review, the Department recommended that the Commission answer these questions in the affirmative. *Id.* at 25. The Commission agreed that MP's proposed PPA and EEA are the most reasonable resources to address MP's demand and energy forecast. *In the Matter of Minnesota Power's Request for Approval of a Power Purchase Agreement with Manitoba Hydro Company*, Docket No. E015/M-11-938, Order (Feb. 1, 2012).

In this docket, MP described how the proposed Project supports hydropower delivery to MP's market:

> The Great Northern Transmission Line supports two sets of agreements between Minnesota Power and Manitoba Hydro. First, the Project supports the 2011 250 MW Power Purchase Agreement and Energy Exchange Agreement between Minnesota Power and Manitoba Hydro (collectively the "250 MW Agreements"), approved by the Minnesota Public Utilities Commission ("Commission") in 2012 in MPUC Docket No. E-015/M-11-938 ("[11-]938 Docket"). In addition to providing needed capacity and energy to Minnesota Power, the 250 MW Agreements contain innovative wind storage provisions that leverage the flexible and

> responsive nature of hydropower to enhance the value of Minnesota Power's significant wind energy investments.

MP Ex. 34 at 6–7 (McMillan Direct). Mr. McMillan continued:

> Moreover, the unique structure of the Manitoba Hydro Agreements means that the Project can meet Minnesota Power's needs, while protecting our ratepayers and also improving overall transmission system reliability and facilitating additional energy sales between Manitoba Hydro and other regional utilities – providing State and regional benefits.
>
> . . .
>
> Not only will the Project meet Minnesota Power's needs by supporting the Manitoba Hydro Agreements, it will also benefit the State and region through increased reliability and capacity to import hydropower from Manitoba. Given Manitoba Hydro's current and pending agreements with other Minnesota and regional utilities,[] Manitoba Hydro requires the transmission capacity available with a 500 kV line.

*Id.* at 12, 21. In response to Department Information Request No. 6, MP provided additional information on MH's agreements with various utilities in Minnesota and a utility in Wisconsin. DOC Ex. 52 at SS-3 (Shah Direct). That information indicates that there are various Transmission Service Requests ("TSRs") between MISO and MH that involve MP and Wisconsin Public Service ("WPS"). *Id.* The WPS TSRs provide support for potential need for more transmission capacity in addition to the capacity required for the MP agreements. *Id.* at 12.

Department witness Mr. Shah testified regarding the Regional Energy Information System ("REIS") data MP filed with the Department, under Minnesota Rules part 7610.0310, for reporting years 2009 through 2013. DOC Ex. 52 at 8, SS-2 (Shah Direct). Company Witness Mr. Rudeck included 2013 REIS data in his Direct Testimony. MP Ex. 43 at AJR, Schedule 1 at 102 (Rudeck Direct). As reported by MP, the REIS data indicates that MP generally has capacity deficits for both summer and winter for the period 2015 through 2019. DOC Ex. 52 at 8 (Shah Direct). A negative figure indicates a deficit while a positive figure indicates a surplus. *Id.*

**Figure 1: Summer**

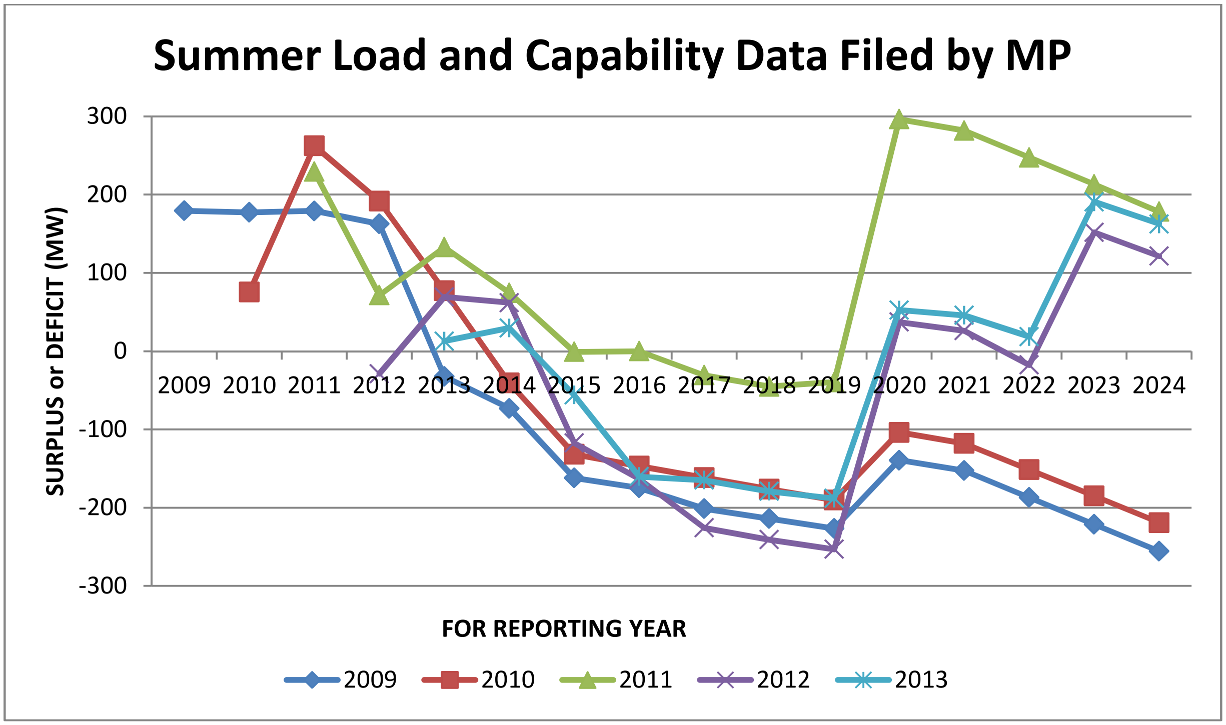
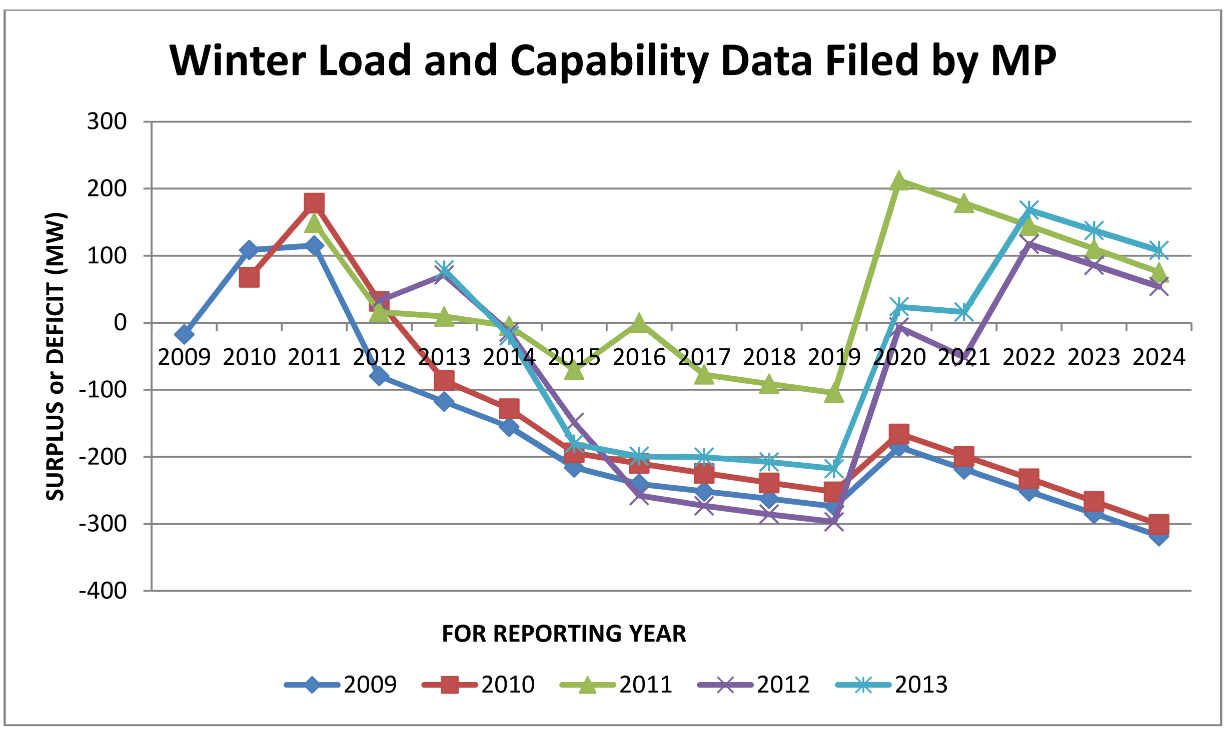



**Figure 2: Winter**



As can be seen above, MP's projected capacity deficits change to a surplus in the year 2020 once the MP-MH 250 MW contract begins. *Id.* at 9.

The Department also evaluated information from MP in its most recent IRP, which MP filed with the Commission, in Docket No. E015-RP-13-53 (the "13-53 Docket"). *Id.* at 9–10; MP Ex. 20 at 20 (Appendix J to Petition). MP stated the following:

> Minnesota Power recognizes that not all projected growth in its industrial customer class will be forthcoming exactly on its proposed schedule. Through its econometric forecasting processes and by working closely with customers, Minnesota Power identified and included with its AFR2012 forecast submittal four scenarios for this growth potential and their impact to electric requirements in its service. For the 2013 Plan, the Wholesale Industrial Customer Addition scenario is utilized, recognizing 166 MW of overall industrial growth for this 15-year time period.

*Id.* After review of MP's IRP, the Department recommended that the Commission require MP to do the following: 1) initiate the process of retiring or selling Taconite Harbor Unit 3 so that the unit is removed from MP's system by 2015; 2) switch the fuel of Laskin Units 1 and 2 to natural gas by 2015; 3) add 100 to 200 MW of wind capacity in the 2014–2016 time frame as long as the resource is reasonably priced; 4) add about 200 MW of intermediate capacity in the 2015–2017 time frame as long as the resource is reasonably priced; and 5) procure energy savings equal to 1.87% of retail sales. DOC Ex. 52 at 10 (Shah Direct).

What is meaningful for this case is that the Commission approved MP's most recent IRP and its 2013 Advanced Forecast Report. *In the Matter of Minnesota Power's 2013–2027 Integrated Resource Plan*, Docket No. E-015/RP-13-53, Order Approving Resource Plan, Requiring Filings, and Setting Date for Next Resource Plan at 7–8 (Nov. 12, 2013). Notably, even after approval of the 250 MW PPA in the 11-938 Docket, the Commission determined that MP needed to add capacity to its system. *Id.*

The Department concluded that the accuracy of the forecast of demand has already been addressed as to the 250 MW of generation from MH; therefore, the Department agreed that Minnesota Rules part 7849.0120(A)(1) has been met. DOC Ex. 52 at 13 (Shah Direct). 250 MW of generation continues to be needed going forward to serve MP's customers reliably. *Id.*

#### 2. Minn. R. 7849.0120(A)(2): MP's Existing or Expected Conservation Programs are Not a Reasonable Alternative to the Proposed Project

Prior to granting a CN application, the Commission must consider the effects of an applicant's existing or expected conservation programs and state and federal conservation programs. Minn. R. 7849.0120(A)(2). After analysis, the Department determined that MP's conservation programs, planned or existing, are not a reasonable alternative to the proposed Project. DOC Ex. 53 at 20–21 (Rakow Direct). First, conservation programs were weighed as an alternative to the SPSA and EEA before the Commission approved those agreements. *Id.* Second, the interface between Manitoba and the United States is unable to accommodate increased transfer of energy from Manitoba into the United States. *Id.*; MP Ex. 9 at 107–108 (Petition). Conservation (lower demand) on the U.S. side of the border would not change that fact. Ex. 53 at 21 (Rakow Direct). Thus, the conservation alternative is not reasonable. *Id.*

#### 3. Minn. R. 7849.0120(A)(3): MH Has Not Impermissibly Promoted Use of Its Power

The Department concludes that MH has not impermissibly promoted use of its power, consistent with Minnesota Rules part 7849.0120(A)(3). First, MH is not the CN applicant in this proceeding, MP is. Second, it is true that Manitoba Hydro has been promoting use of its hydro power. Minnesota law, however, states more broadly that the Commission should consider "the effects of promotional practices of the applicant that may have given rise to the increase in the energy demand." Minn. R. 7849.0120(A)(3). The Department does not believe that Manitoba

Hydro has promoted increased demand for energy overall. DOC Ex. 53 at 13 (Rakow Direct). Instead, it has marketed its *brand* of energy. *Id.*

Further, given that the Mercury Air Toxics Standard ("MATS") is scheduled to take effect soon and is expected to affect the availability of coal-fired, base load power in the MISO region, and given that generation plants in Minnesota and the region continue to age, it is fair to conclude that power from Manitoba Hydro will be needed in Minnesota and surrounding states. *Id.*

#### 4. Minn. R. 7849.0120(A)(4): Current and Planned Facilities Not Requiring a CN Are Insufficient to Meet Demand

In evaluating a CN application, the Commission must consider the ability of current facilities and planned facilities not requiring CNs to meet the future demand. Minn. R. 7849.0120(A)(4). In this case, the Department has concluded that current and planned facilities not requiring CNs are not a reasonable alternative to the proposed Project. The current interface between Manitoba and the United States is unable to accommodate increased transfer of energy from Manitoba into the United States. MP Ex. 9 at 107–108 (Petition). Not building the proposed GNTL, or an alternative, would not change that fact. DOC Ex. 53 at 13 (Rakow Direct).

### C. Under Minn. R. 7849.0120(B), the Proposed GNTL is the Most Reasonable Alternative to Meet Forecasted Energy Demand

To begin the alternatives analysis, it is helpful to note applicable state law regarding consideration of transmission alternatives. First, Minnesota Rules require consideration of "the appropriateness of the size, the type, and the timing of the proposed facility compared to those of reasonable alternatives." Minn. R. 7849.0120(B)(1). Second, Minnesota law requires consideration of distributed generation:

> The Commission shall ensure that opportunities for the installation of distributed generation, as that term is defined in section 216B.169, subdivision 1, paragraph (c), are considered in any proceeding under section 216B.2422, 216B.2425, or 216B.243.

Minn. Stat. § 216B.2426. Third, Minnesota law also requires consideration of renewable energy generating facilities:

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

Minn. Stat. § 216B.2422, subd. 4. The Department used these legal standards, in addition to others referred to below, in evaluating MP's screening analysis for determining the reasonableness of alternatives to the proposed Project. DOC Ex. 53 at 15–21 (Rakow Direct).

**1. Transmission Alternatives**

MP reviewed two alternatives with lower voltages than that of the proposed GNTL: a 230 kV line and a 345 kV line. First, MP concluded that a 230 kV alternative would not meet the long-term needs of the region, would not prove to be cost-effective for customers,[21] and would not be environmentally preferable over the long-term.[22] MP Ex. 9 at 75–77 (Petition). Second, MP screened out a 345 kV alternative based on the assumption that a project equivalent to a 500 kV line would need to be a double-circuit 345 kV line. *Id.* A double-circuit 345 kV line would have similar or higher construction costs (compared to a 500 kV line) and lower surge

[21] Essentially MP stated that a 500 kV transmission facility would be cheaper per unit of electricity transmitted due to the larger size and resulting "economies of scale."

[22] Building a higher voltage project now limits the proliferation of new transmission line corridors in the future.

impedance loading and thus would not be as desirable.[23] *Id.* Finally, the Winnipeg area does not have 345 kV equipment. *Id.* MP indicated that expensive new substation equipment would be required at the Canadian end point to accommodate a 345 kV line, but did not provide an estimate for that cost. *Id.*

MP also considered a higher-voltage 765 kV transmission line as an alternative, but ultimately concluded that it was not reasonable. MP Ex. 9 at 77 (Petition). MP concluded that the fact that there is no 765 kV transmission in the region means that expensive transformation would be required at each substation to interconnect with existing 500 kV and/or 230 kV systems. *Id.* MP did not provide an estimate of the cost of transforming the power but indicated that a 765 kV transmission line would also have increased construction costs and added operational complexity. *Id.* MP decided that the higher cost and increased complexity would outweigh the benefits of additional capacity gained by a 765 kV build, compared to the proposed 500 kV build. *Id.*

The Department evaluated MP's screening process for transmission lines of alternative voltage, and generally determined that MP's screening analysis in the Petition is reasonable. DOC Ex. 53 at 17 (Rakow Direct). Because the 230 kV alternative is sufficient for purposes of MP's Commission-approved SPSA and EEA, the Department also considered the 230 kV alternative in a more detailed analysis, as discussed below. *Id.*

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[23] The surge impedance loading or "SIL" of a transmission line is the MW loading of a transmission line at which reactive power is balanced. *See* JCSP 2008 Fundamentals Workshop, Planning of a Power Transmission System Using Economic Tools (2007), https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Workshop%20Materials/JCSP%20Fundamentals%20Workshop/20080429-30%20JCSP%20Fundamentals%20Workshop%20Item%2005%20Transmission%20Design.pdf.

MP also considered different end points for a transmission line other than the Blackberry substation. MP Ex. 9 at 77 (Petition). In many transmission study scenarios, a Fargo area end point (at times Barnesville is substituted for Fargo) exhibits similar performance and benefits. *Id.* In the end, MP concluded that the Fargo area end point is flawed for several reasons. *Id.*

First, MP stated that there are technical engineering issues, such as aggravating the North Dakota—Manitoba loop flow phenomenon by introducing a new low-impedance path between North Dakota and Manitoba, which would require additional transmission upgrades to relieve constrained generation outlet capability for North Dakota, Manitoba, or both (MP did not provide the costs of these upgrades). *Id.* Second, MP indicated that a transmission facility that transmits hydroelectric power produced outside the United States, and crosses any portion of North Dakota, must have the approval of the legislative assembly under North Dakota law. *Id.* at 78. This second concern means that the practical impact is that the end point for a Fargo area end point would have to be on the Minnesota side of the Red River due to uncertainties inherent in the legislative process. *Id.* Finally, MP indicated that a Fargo area end point cannot achieve the timeline required by MP's SPSA and EEA agreements. *Id.*

While the Department could not confirm MP's statement about North Dakota law, in general the Department agreed with the results of MP's screening analysis.[24] DOC Ex. 53 at 18 (Rakow Direct).

### 2. Generation Alternatives

In its Petition, MP stated the following as to generation alternatives:

> [I]n the 938 Docket [E015/M-11-938], the Department and Commission specifically examined whether "the resources proposed in the PPA represent the most appropriate resources to

[24] A Fargo area end point would have additional issues regarding inappropriate cost allocations, as discussed further below in the section on financial background.

> meet [Minnesota Power's] resource needs over the period 2020 through 2035." The Department and Commission both answered that question in the affirmative.

MP Ex. 9 at 71–72 (Petition). The Company clarified that it reviewed numerous generation alternatives before signing the EEA and SPSA. MP Ex. 43 at 29 (Rudeck Direct). Thus, MP did not reconsider whether alternative generation sources should be pursued for this CN proceeding. *Id.* In this case, new generation resources would not be able to deliver the capacity and energy called for under the SPSA and EEA. MP Ex. 9 at 72 (Petition).

The Department agreed with MP that new generation, distributed generation, and Community-Based Energy Development ("C-BED") are not reasonable and prudent alternatives to the proposed Project. DOC Ex. 53 at 20 (Rakow Direct).

### 3. Review of Transmission Studies

The Department reviewed various transmission studies to understand how the studies might impact an economic comparison of alternatives. *Id.* at 21–28. The studies often compared eastern and western alternatives. *Id.* The proposed GNTL was analyzed in the following transmission studies:

- *Northern Area Study* ("NAS");
- *MH-US TSR Sensitivity Analysis Draft Report* ("TSR Report");
- *Manitoba Hydro Wind Synergy Study* ("Synergy Study");
- *Dorsey—Iron Range 500 kV Project Preliminary Stability Analysis Draft Report* ("Stability Report"); and
- *Manitoba—United States Transmission Development Wind Injection Study* ("Wind Report").

*Id.* at 21–22. The transmission studies also discussed various substations in Minnesota, including the Blackberry substation. *Id.* at 22.

The Wind Report was the only study to show significant differences between the eastern and western alternatives in terms of economic performance. DOC Ex. 53 at 28 (Rakow Direct). All of the other studies found minimal economic differences between the eastern and western alternatives. *Id.* An eastern option, like the GNTL, is more economical in this regard. *Id.*

#### 4. Cost Analysis of Alternatives

##### a. Summary of Construction Costs for the 500 kV Transmission Option and the 230 kV Transmission Option

As indicated above, the Department wanted to compare the costs of a 230 kV transmission alternative with the costs of the proposed GNTL. The following table represents the cost estimate in the MISO FCA for the 500 kV transmission option:

**Table 1: Cost Estimate in MISO Facilities Construction Agreement**

| Funding Option | Total GNTL Cost | MP Responsibility | MH-CIAC | MH-Assignee |
|---|---|---|---|---|
| 100 percent MP Ownership | $676,242,900 | $311,071,700 | $365,171,200 | |
| Assignment | $676,242,900 | $311,071,700 | $33,812,100 | $331,359,100 |

MP Ex. 38 at 10 (Donahue Direct). The Company estimated that the proposed Project would cost between $557.9 to $710.1 million. *Id.* at 5. Regarding MP's capital cost estimate for a 230 kV transmission alternative, MP estimated that such a cost would range from $277 million to $355 million in 2013 dollars. *Id.* at 12.

##### b. Financial Background

Under its proposal, MP would be responsible for financing 46% of the total construction costs, or $311,071,700, using the FCA estimate from above (and used in the paragraphs below). DOC Ex. 53 at 31 (Rakow Direct). MH would be responsible for financing 5% of the total construction costs, or $33,812,100, because MH would have to pay MP 5% of the construction cost as a CIAC. *Id.* MP's responsibility for 46% of the financing plus MH's 5% CIAC equals MP's 51% ownership share. *Id.*

For now, MH is also responsible for financing the remaining 49% of the total construction costs, or $331,359,100. *Id.* MP has made it clear, however, that the 49% share is likely to be transferred to another Minnesota MISO transmission owner, or MP will assume 100% (its own 51% share plus the 49% minority share) if that does not occur. *See* MP Ex. 34 at 13–14 (McMillan Direct); MP Ex. 38 at 8 (Donahue Direct). Any transfer would require MP's consent. MP Ex. 40 at 3 (Donahue Rebuttal). It would also require Commission approval under Minnesota Rules part 7849.0400. If the minority ownership were transferred to another Minnesota MISO transmission owner, the entity receiving MH's ownership share would be responsible for financing the 49% share (or $331,359,100). MP Ex. 38 at 8 (Donahue Direct).

If MH does not sell its share of the proposed Project, then MP would own 100% of the proposed GNTL by mid-year 2016. *Id.* If MP were to assume 100% ownership, MH would provide its 49% share ($331,359,100) to MP as another CIAC. *Id.* In that case, while all of the costs of the GNTL would be attributable to MP, 49% of the costs would be offset by this CIAC (in addition to the 5% CIAC discussed above). *Id.* Effectively, this structure means that MH would be financially responsible for 49% of the costs of the GNTL even though MP would be the owner. *Id.*

MP must also recover its capital costs. DOC Ex. 53 at 32 (Rakow Direct). MP's costs would be offset by MH's 5% CIAC payment, assumed to be $33,812,100. That offset leaves 46% of total costs, or $311,071,700, yet to be recovered, which can be broken down as follows:

- 17.7% of total costs, or $119,695,000, attributable to the ROA; and

- 28.3% of total costs, or $191,376,700, attributable to the SPSA.

The costs attributable to the SPSA (28.3%) would be recovered through MP's Transmission Cost Recovery Rider ("TCR Rider"), potentially through base rates after a rate case for retail customers, and through formula rates set by FERC in MISO's Attachment O process for MP's/ALLETE's wholesale customers. *Id.* MP expects to recover the costs attributable to the future ROA (17.7 percent of the total or $119,695,000 using the FCA estimate) from MH through a scheduling fee arrangement (also referred to as a "Monthly Must Take Fee") expected to be included in the proposed ROA. *Id.* MP expects to propose that the 17.7% share of investment for the proposed GNTL be placed into MP's rate base or the TCR Rider with the Monthly Must Take Fee paid by MH as an offset. *Id.* at 33.

If MH transfers its ownership interest to another entity, it would not affect MISO's pricing zone: MH would still be responsible for 49% of the proposed Project's costs. MP Ex. 40 at 4 (Donahue Rebuttal).

There is also the question of MP's recovery of operation and maintenance ("O&M") expenses from its customers. *Id.* at 5. MP's share of O&M expenses remains at 33.3% (rather than 28.3%) because MP agreed to that level of cost recovery in exchange for MH agreeing to a 5% increase in its capital funding obligation. *Id.* at 5–6. While MP will initially be responsible for the additional 17.7% of O&M costs, it will be recovered from MP as a Monthly Must Take Fee. *Id.* at 6.

A summary of the financial background can be provided as follows:

**Table 2: Summary of Financial Background**

| | **Final Ownership Structure** | |
|---|---|---|
| **Responsibility For:** | **100 % MP** | **51 % MP / 49 % Other** |
| **Investment** | | |

| | | |
|---|---|---|
| MP | 46.0% | 46.0% |
| MH (CIAC) | 54.0% | 5.0% |
| MH-Assignee | NA | 49.0% |
| **Total** | 100.0% | 100.0% |
| **Rev. Req.--Capital Cost** | | |
| MP Ratepayer | 28.3% | 28.3% |
| MH (ROA Fee) | 17.7% | 17.7% |
| MH (CIAC) | 54.0% | 5.0% |
| Undefined | 0.0% | 0.0% |
| MH-Assignee | NA | 49.0% |
| **Total** | 100.0% | 100.0% |
| **Rev. Req.--O&M** | | |
| MP Ratepayer | 33.3% | 33.3% |
| MH (ROA Fee) | 17.7% | 17.7% |
| MH (CIAC) | 49.0% | 0.0% |
| Undefined | 0.0% | 0.0% |
| MH-Assignee | NA | 49.0% |
| **Total** | 100.0% | 100.0% |

MP Ex. 40 at 8 (Donahue Rebuttal).

#### c. Analysis of Internal Costs

The Commission must consider "the cost of the proposed facility and the cost of energy to be supplied by the proposed facility compared to the costs of reasonable alternatives and the cost of energy that would be supplied by reasonable alternatives." Minn. R. 7849.0120(B)(2). In addition, the Commission must evaluate the benefits of enhanced regional reliability, access, or deliverability to the extent these factors improve the robustness of the transmission system or lower costs for electric consumers in Minnesota.[25] Minn. Stat. § 216B.243, subd. 3(9).

[25] If a renewable generation facility had passed the screening analysis, Minnesota Statutes § 216B.2422, subd. 4 would also apply. In this instance, however, no renewable generation facility passed the screening analysis. DOC Ex. 53 at 37 (Rakow Direct).

As indicated above, the proposed GNTL is estimated to cost between $557.9 million and $710.1 million (2013 dollars). DOC Ex. 53 at 37 (Rakow Direct). Given that MP's ratepayers would be responsible for 28.3% of the proposed GNTL, MP's ratepayers would be responsible for between $158 million and $201 million of construction costs. *Id.* Specifically, using the estimated project cost in the facilities construction agreement, MP's ratepayers would be responsible for $191.4 million (28.3%) of construction costs. *Id.*

Regarding the 230 kV transmission alternative, its total cost is estimated to range from $277 million to $355 million (2013 dollars). *Id.* at 38. Unlike the 500 kV transmission alternative, for which ratepayers would be responsible for 28.3% of the cost, MP's ratepayers would be responsible for 100% of the costs of the 230 kV alternative. *Id.*; MP Ex. 34 at 19 (McMillan Direct).

As to MP's revenue requirements for each alternative, the proposed GNTL would add $30.1 million and the 230 kV alternative would add $52.2 million to MP's MISO rates. MP Ex. 38 at 15 (Donahue Direct). Therefore, the proposed GNTL would have far lower revenue requirements than a stand-alone 230 kV transmission line. DOC Ex. 53 at 38 (Rakow Direct). Neither consideration of O&M costs nor consideration of line losses would change this conclusion (higher voltage lines actually have higher demand and energy savings on average). *Id.* at 39–40.

The proposed GNTL would likely also result in long-term cost savings for electric consumers in Minnesota. DOC Ex. 53 at 40–42 (Rakow Direct). The result of the locational marginal prices ("LMP") analysis is a slight decrease in Minnesota LMPs in 2022 (either 4¢ in the business as usual ("BAU") case or 1¢ in the high growth case) and a larger decrease in Minnesota LMPs in 2027 (either 78¢ in the BAU case or 30¢ in the high growth case). *Id.* at 41.

While the Department agreed with MP that the near term impact is not material, the longer term impact, while subject to significant uncertainties, indicates the potential for savings for the region attributable to the proposed GNTL. *Id.* at 42.

Considering the cost of the proposed GNTL and the cost of energy to be supplied by the proposed GNTL compared to the costs of reasonable alternatives and the cost of energy that would be supplied by reasonable alternatives, the Department concluded that the proposed GNTL is the preferred alternative. *Id.*

### 5. Analysis of Societal Cost

The Commission must consider "the effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives." Minn. R. 7849.0120(B)(3). Also, the Commission must:

> [T]o the extent practicable, quantify and establish a range of environmental costs associated with each method of electricity generation. A utility shall use the values established by the commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the commission, including resource plan and certificate of need proceedings.

Minn. Stat. § 216B.2422, subd. 3(a).

This is a CN proceeding where resource options are proposed to be selected. The Department recommended that the Commission order MP to use the Commission's externality values in future CN proceedings and MP agreed. DOC Ex. 53 at 43 (Rakow Direct); MP Ex. 35 at 8–9 (McMillan Rebuttal).

In addition, the Commission's estimated range of the cost of future $CO_2$ regulation is not required to be used in this proceeding. *See* Minn. Stat. § 216H.06. Because section 216H.06 states that the range of costs of future $CO_2$ regulation applies to "electricity generation resource acquisition proceedings," it would appear that Minnesota Statutes do not require the $CO_2$

regulation range of costs to be used in this transmission proceeding. DOC Ex. 53 at 43–44 (Rakow Direct). In economic terms, however, it does not matter if an emissions increase (and thus emissions costs) is caused by selecting a high-emission generation alternative or a high-loss transmission alternative. *Id.* at 44. Thus, despite section 216H.06's language, the Department concludes that the Commission's $CO_2$ regulation cost estimates should be applied to the cost calculations in all transmission CN proceedings so that $CO_2$ and other emission costs are reasonably considered in resource selections. *Id.* at 44.

Regarding the effect of the Commission's externality values and cost of future $CO_2$ regulation on internal costs, consideration of the Commission's externality and $CO_2$ regulation cost estimates indicates a slight benefit of the GNTL but does not materially change the analysis of line losses (as seen in the following table). *Id.* at 44–45.

**Table 3: Economic Benefit of Line Loss Savings with Externalities**

| Item | Amount | Item | Amount | Total Benefit |
|---|---|---|---|---|
| **MWh Saved** | 79,849 | **MW Saved** | 21.1 | |
| **$/MWh** | $49.28 | **$/MW-yr.** | $89,500 | |
| **Energy Savings** | $3,934,959 | **Demand Savings** | $1,888,450 | **$5,823,409** |

Pursuant to the Department's request, MP adjusted the Company's analysis to include the Commission's cost of future $CO_2$ regulation value. *Id.* at 45. The results indicate that inclusion of the Commission's $CO_2$ values is relatively minor. *Id.* Consideration of the impact of $CO_2$ values on the LMP makes the proposed GNTL slightly less beneficial as the LMP decreases by a lower amount. DOC Ex. 53 at 45 (Rakow Direct). The production cost impact is similar, with production costs increasing by a larger amount with $CO_2$ values than without $CO_2$ values in the 2022 BAU case ($0.6 million versus $0.2 million) and decreasing by a smaller amount in the 2027 BAU case ($3.3 million versus $1.5 million). *Id.*

### 6. The GNTL's Impact on Fossil Fuel Generation

The proposed GNTL would directly and indirectly replace coal generation in Minnesota and would also indirectly replace natural gas generation.[26] DOC Ex. 53 at 46 (Rakow Direct). As decided in the 13-53 Docket (resource planning), MP is planning on shutting down Taconite Harbor unit 3 and refueling Laskin units 1 and 2 (switching from coal to natural gas). *Id.* The SPSA is part of MP's plan to replace the lost energy and capacity. *Id.* In addition, the indirect impact of the proposed GNTL is to enable the addition of resources (MH's generation to meet the SPSA) to the MISO dispatch stack. To the extent that coal units are on the margin (the load following unit), and MH's generation has a lower variable cost (and thus would be dispatched first) or is must run, hydro generation will replace coal generation imported via the proposed GNTL. *Id.* The same consideration applies to natural gas generation: to the extent that natural gas units are on the margin and MH's generation has a lower variable cost (would be dispatched first), hydro generation will replace natural gas generation imported by the GNTL. *Id.*

### 7. A Barnesville Alternative End Point

The Department considered the reasonableness of having an endpoint for the proposed Project in Barnesville, Minnesota, but it did not recommend this alternative. DOC Ex. 53 at 47–49 (Rakow Direct). Having an endpoint in Barnesville would not be reasonable because 1) the proposed GNTL would not qualify for cost sharing and 2) such a design would represent a misallocation of costs because utilities in the Otter Tail Power Company's pricing zone would be required to pay for a project that they have not requested. *Id.* at 47.

[26] In terms of the MISO dispatch order, hydro generation will likely not replace wind generation. Wind has little to no variable cost and is often operated as a "must run" unit. Thus, wind is unlikely to be the load following unit and MH is unlikely to replace wind via the dispatch order. In MP's IRP, however, hydro and wind are both resources that must compete with each other to serve the Company's energy needs. It is possible that if MH had not been selected, additional wind (presumably accompanied by natural gas capacity and energy) would have been selected.

### D. Minn. R. 7849.0120(C): The Proposed Project Will Provide Benefits to Society in a Manner Compatible with Protecting the Natural and Socioeconomic Environments, Including Human Health

As indicated above, DOC-EERA completed the ER, which satisfied consideration of all regulatory requirements governing requisite environmental review of the proposed Project. DOC's recommendation to grant a CN for the proposed GNTL assumes that the Commission determines the ER to satisfy all environmental criteria, including Minnesota Rules part 7849.0120(C).

## II. CONDITIONS ON THE APPROVAL OF MP'S APPLICATION FOR A CERTIFICATE OF NEED

### A. Conditioning a CN on Commission Approval of the ROA and FCA Agreements

MP, LPI, and DOC are in agreement that granting a CN for the proposed GNTL should be conditioned on Commission-approval of MP's 133 MW ROA (second EEA and ESA) and the Facilities Construction Agreement (discussed above, which has been approved by FERC) (which is in addition to the already-approved 250 MW SPSA). DOC Ex. 55 at 1–2 (Rakow Rebuttal); LPI Ex. 51 at 2–3 (Kollen Surrebuttal); MP Ex. 35 at 10 (McMillan Rebuttal).

### B. The Commission Should Impose a "Soft Cap" on Cost Recovery for the Proposed GNTL

LPI proposed a "hard cap" on cost recovery pertaining to the proposed GNTL for "as spent" dollars. LPI Ex. 49 at 11–13 (Kollen Direct).

The Department evaluated LPI's proposal and instead proposed a "soft cap" on recovery. DOC Ex. 55 at 2 (Rakow Rebuttal). The Department has typically addressed concerns regarding cost caps in a rider or rate case proceeding in which cost recovery from retail ratepayers is first requested. *Id.* at 2–3. Thus, the Commission will consider a subsequent cost recovery proceeding regarding MP's proposal such that it may not be necessary to address cost caps at this time. *Id.* at 3. The Department, however, certainly does not oppose making clear to MP the terms of its future cost recovery, consistent with the Commission's approach regarding cost recovery of projects in other CNs: 1) MP would be limited to recover in riders only the amount of costs that MP proposes in this proceeding; 2) MP could request recovery of costs above the CN amount only in a rate case; and 3) MP would have the burden of proof to show that any such costs are prudent and why it would be reasonable to recover such costs from ratepayers. *Id.*

The Commission stated the purpose of such an approach in a 2010 proceeding regarding cost recovery of energy facilities owned by Northern States Power, d/b/a Xcel Energy in Docket No. E002/M-09-1083:

> The Commission will allow Xcel to recover, through its RES rider, only the costs up to the amounts of the initial estimates at the time the projects are approved as eligible projects. No amounts above what Xcel initially indicated the projects would cost will be allowed to flow through the RES rider. Nor will additional cost overruns be eligible for deferred accounting.
>
> However, Xcel will be allowed to seek recovery, on a prospective basis, of additional costs at the time of its next rate case, upon a showing that it is reasonable to require ratepayers to pay for any such additional costs. This approach allows Xcel to recover the majority of the costs for projects eligible for RES rider recovery promptly, while providing at least some incentive for Xcel to minimize costs and help protect ratepayers.

By contrast a "hard cap" would not be appropriate because such a provision would inappropriately communicate to the Company to incur non-capital-intensive costs instead of capital costs, which may lead to higher costs overall for ratepayers. Tr. Vol. 2 at 92 (Rakow). In addition, issues surrounding details of cost recovery in this CN proceeding are not truly relevant to the issue of need. *Id.* It is entirely reasonable and in the best interests of all rate payers to give MP an incentive to minimize overall costs and to put MP on notice in this proceeding about how future cost recovery will work. *Id.* at 93; DOC Ex. 55 at 3 (Rakow Rebuttal). The Department recommends incentivizing construction of least-cost projects, which will lead to a least-cost system. Tr. Vol. 2 at 93–94 (Rakow). A hard cap on cost recovery does not achieve that goal and is not in the best interests of ratepayers. *Id.*

### C. The Department's Evaluation of the Financial Impacts of the CN

LPI raised multiple issues regarding the financial impacts of MP's application for a CN. LPI Ex. 49 at 19–28 (Kollen Direct). The Department responded to each issue in turn. *See generally* DOC Ex. 57 (Johnson Surrebuttal).

#### 1. Allowance for Funds Used During Construction

LPI's witness testified that the Commission should direct the Company to accrue Allowance for Funds Used During Construction ("AFUDC") on its balance of construction work in progress ("CWIP") rather than seek current recovery of a return on CWIP (carrying charges) during the construction period. LPI Ex. 49 at 19–23 (Kollen Direct). Mr. Kollen stated that the Commission should do so in this proceeding to pre-empt any subsequent request by the Company to obtain current recovery of carrying charges in its annual TCR Rider. *Id.* at 4.

The Department did not agree that LPI's proposal was reasonable for the following reasons. DOC Ex. 57 at 5–9 (Johnson Surrebuttal). First, cost recovery issues are not generally addressed in CN proceedings because, at minimum, there has been no notice to ratepayers and other members of the public that cost recovery will be an issue in this case. DOC Ex. 57 at 6 (Johnson Surrebuttal); Minn. Stat. § 216B.16, subd. 1. Instead, cost-recovery issues are usually addressed in cost-recovery proceedings, such as riders and rate cases when MP chooses to request cost recovery from the Commission. *Id.* It is in those proceedings where proper notice regarding rate recovery is provided and where the record can be sufficiently developed to determine whether certain cost recovery is in the best interests of ratepayers. Tr. Vol. 2 at 70 (Johnson). The Department intervenes in these cases and represents the public interest, and thus, the interests of all Minnesota ratepayers, where it may make specific recommendations about how cost recovery is in the best interests of ratepayers. LPI represents the interests of one group of ratepayers that advocates for its own interests in matters before the Commission. LPI Ex. 49 at 2 (Kollen Direct).

Second, Minnesota's Transmission Cost Recovery Statute specifically allows utilities to seek current recovery of a return on CWIP during the construction period, which is prior to when a project is placed in-service. *Id.*; Minn. Stat. § 216B.16, subd. 7b(b)(5). This provision is a policy judgment that the Minnesota legislature has made. *Id.*; MP Ex. 35 at 12 (McMillan Rebuttal). In addition, the Department is not aware of any instances where the Commission has denied current recovery of a return on CWIP in a utility's TCR Rider on the basis that the project was under construction, and it believes that doing so would constitute a significant departure from Commission precedent. DOC Ex. 57 at 6 (Johnson Surrebuttal).

Third, earning a current return on CWIP would result in lower overall capital costs to be recovered in rates over the life of the GNTL facility, if the proposed GNTL is approved. *Id.* at 7. The capital costs would be lower because the utility is provided a current return on CWIP in lieu of capitalizing more AFUDC costs during the construction phase of the project. *Id.* This fact, however, does not necessarily result in a benefit to ratepayers because annual revenue requirements would be significantly higher during the construction phase of the Project due to the current return on CWIP. *Id.* In other words, the $55 million in AFUDC savings would be offset by the current return on CWIP that MP is allowed to collect during the construction phase of the Project. *Id.* But, in the end, precluding a current return on CWIP would delay cost recovery until a project is in service, which would increase total overall revenue requirements. *Id.* Such a delay may or may not result in a detriment to ratepayers. *Id.* at 8.

In exchange for recovery of a current return on CWIP during the construction phase of the facility, MP is forgoing additional AFUDC costs that would otherwise be capitalized and charged to ratepayers over the life of the asset. DOC Ex. 57 at 8 (Johnson Surrebuttal). Therefore, to determine whether this different rate treatment represents an overall cost or benefit for ratepayers, it would be necessary to calculate the present value of total annual revenue requirements over the life of the project under both methods: 1) allowing MP to earn a return on CWIP during the construction period, and 2) allowing MP to incur higher AFUDC costs and earn a current return on the higher capitalized amount over the life of a facility. *Id.* Given that these calculations must include numerous assumptions on future rates of return, AFUDC rates (costs), discount rates, depreciable lives, etc., the Department is unable to precisely determine which method would result in the lowest real-dollar[27] costs for ratepayers. *Id.* This fact is another reason why these issues are not typically dealt with in CN proceedings where no notice is provided to ratepayers or interested parties that rate recovery will be addressed. *Id.* at 6.

Fourth, there would be value for MP associated with allowing MP to begin recovery of a project's costs before it is placed in-service, including improved cash flow and better financial ratings. DOC Ex. 57 at 8. There may arguably be benefits to ratepayers of reduced rate shock, assuming that the project is eventually placed in service, and possibly benefits of MP's improved cash flow and better financial ratings. *Id.* at 8–9. Again, these values or benefits are difficult to measure and may or may not come to fruition. *Id.* 9.

[27] Nominal dollar costs adjusted for inflation.

### 2. Rider Recovery Timeframe

LPI recommended that the Commission allow recovery of GNTL costs only through MP's TCR Rider, or another rider, rather than ever allowing cost recovery through base rates. LPI Ex. 49 at 4, 23–26 (Kollen Direct).

The Department did not agree. DOC Ex. 47 at 10–11 (Johnson Surrebuttal). First, the Project will likely be eligible for recovery under the TCR Statute if the Commission approves the CN in this proceeding. Minn. Stat. § 216B.16, subd. 7b(b)(9); DOC Ex. 47 at 10 (Johnson Surrebuttal). Second, better ratemaking outcomes may be achieved for customers through a general rate case. *Id.* Third, under current Commission precedent, MP would not be allowed to recover any of its internal capitalized costs if the Project were required to permanently stay in a rider. *Id.* Fourth, under current Commission precedent, MP would not be allowed to recover any additional capital costs in a rider that are over and above the estimates used in this proceeding. *Id.* Finally, if the Commission were to require MP to keep the Project permanently in a rider (which the Department believes the Commission has never done), the Commission would essentially be pre-determining rate recovery of the Project for the next 55 years.[28]

### 3. Cost Allocations and Rate Design

LPI asked the Company to "address in its responsive testimony the effects on customer classes, including its calculations of these effects, and the opportunity to partially remedy the subsidies provided by the LPI class to other classes so that large customers are not further harmed over the life of the GNTL project." LPI Ex. 49 at 27–28 (Kollen Direct). The Company did so. MP Ex. 35 at 15–16 (McMillan Rebuttal).

[28] The expected service life of the Project is 55 years. MP Ex. 9 at 27 (Initial Petition).

The Department concluded that the rate design method in this proceeding as shown in MP Ex. 34 at DJM-R, Schedule 2, Table 1 is similar to the rate design method in MP's most recent Commission-approved TCR Rider in Docket No. E015/M-11-695 and in MP's most recent TCR Rider in Docket No. E015/M-14-337, which is currently before the Commission. DOC Ex. 57 at 13 (Johnson Surrebuttal). The Department agrees with MP's recommendation that the Commission take no action in this proceeding regarding future cost allocation and rate design issues that are to be addressed in future riders and general rate case proceedings. *Id.* at 14.

## CONCLUSION

The Department concludes after analysis of the record under Minnesota Rules 7849.0120 and Minnesota Statutes section 216B.243, subdivision 3, that the proposed Project is needed in Minnesota, neighboring states, and the region and that a more reasonable alternative has not been demonstrated. Therefore, the Department recommends that the Commission approve the proposed Project. Granting a CN for the proposed GNTL should be conditioned on the Commission:

- approving MP's 133 MW ROA (second EEA and ESA) and the FCA[29];
- ordering MP to use the Commission's externality values in future CN proceedings; and
- ordering the following "soft cap" on cost recovery:
    1. MP would be limited to recover in riders only the amount of costs that MP proposes in this proceeding;
    2. MP could request recovery of costs above the CN amount only in a rate case; and

[29] As noted above, the FCA was approved by FERC.

3. MP would have the burden of proof to show that any such costs are prudent and why it would be reasonable to recover such costs from ratepayers.

There are not any unresolved issues between DOC and MP at this time.

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Respectfully submitted,

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