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January 16, 2015

VIA E-FILING AND EMAIL

The Honorable Judge Ann O'Reilly (ann.oreilly@state.mn.us)
Office of Administrative Hearing
600 North Robert Street
P.O. Box 64620
St. Paul, MN 55164-0620

Re: In the Matter of the Request of Minnesota Power for a Certificate of Need for the Great Northern Transmission Line
Docket No. E-015/CN-12-1163
OAH Docket No. 65-2500-31196

Dear Judge O'Reilly:

Attached for filing in the above docket please find the following documents:

1. Post-Hearing Reply Brief of the Large Power Intervenors, including the Affidavit of Lane Kollen;
2. Redline of Large Power Intervenors' Comments to Minnesota Power's Proposed Findings of Fact, Conclusions of Law and Recommendation (Public version);
3. Redline of Large Power Intervenors' Comments to Minnesota Power's Proposed Findings of Fact, Conclusions of Law and Recommendation (Trade Secret version); and
4. Certificate of Service.

Very truly yours,

/s/ Andrew P. Moratzka

Andrew P. Moratzka

APM
Enclosures

BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
100 Washington Square, Suite 1700
Minneapolis, MN 55401-2138

FOR THE PUBLIC UTILITIES COMMISSION OF THE STATE OF MINNESOTA
121 Seventh Plaza East, Suite 350
St. Paul, MN 55101-2147

In the Matter of the Request by Minnesota Power for a Certificate of Need for the Great Northern Transmission Line	PUC Docket No. E-015/CN-12-1163 OAH Docket No. 65-2500-31196

POST-HEARING REPLY BRIEF

OF THE LARGE POWER INTERVENORS

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The certificate of need application (the "Application") filed by Minnesota Power ("Minnesota Power" or the "Company") in this docket is one without precedent. Never before has a Minnesota utility proposed a transmission line to interconnect a large generating unit where the cost of the proposed transmission line and the cost of energy to be supplied by it are on virtual cost parity with a reasonable generation alternative and the cost of energy to be supplied by that alternative. The Large Power Intervenors ("LPI")[1] is a consortium of large industrial customers receiving electric service from Minnesota Power that has been directly impacted by significant rate increases imposed by the utility over the past decade. LPI has been an active participant in this proceeding since filing its Petition to Intervene on January 16, 2014. LPI provided Direct Testimony on September 19, 2014, and Surrebuttal Testimony on November 7, 2014, and provided testimony in person at the Commission's hearing in this docket on November 14, 2014. LPI submitted a post-hearing brief on December 22, 2014,[2] and now submits this reply brief to rebut specific claims, allegations, and misleading information posited by Minnesota Power and the Department of Commerce – Division of Energy Resources (the "Department") in their initial briefs filed on December 19, 2014.

I. INTRODUCTION

Throughout the course of this docket, LPI has advocated means of ensuring that Minnesota Power's investments in the Great Northern Transmission Line (the "GNTL" or the "Project") will be prudent and recovered in a manner that is fair to its customers in light of the dramatic increase in rates over the past decade. No party to this proceeding has disputed that rates for the large power class have ballooned approximately 62.5% since 2007.[3] In light of the unique set of circumstances presented by this docket, LPI urges the Administrative Law Judge

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[1] ArcelorMittal USA (Minorca Mine); UPM-Blandin Paper Company; Boise Paper (Boise), a Packaging Corporation of America company, formerly known as Boise, Inc.; Enbridge Energy, Limited Partnership; Hibbing Taconite Company; Mesabi Nugget Delaware, LLC; Verso Corporation (successor-in-interest to NewPage Corporation's Duluth Mill); PolyMet Mining, Inc.; Sappi Cloquet, LLC; USG Interiors, LLC; United States Steel Corporation (Keetac and Minntac Mines); and United Taconite, LLC.

[2] Accepted as timely filed by the Administrative Law Judge. *In the Matter of the Request of Minnesota Power for a Certificate of Need for the Great Northern Transmission Line Project*, Docket No. E-015/CN-12-1163, ORDER GRANTING LARGE POWER INTERVENORS' MOTION FOR EXTENSION OF TIME FOR FILING INITIAL BRIEF (Jan. 9, 2015).

[3] Ex. 60, *Document Regarding Approval of Boswell 3 Environmental Improvement Rider in Docket No. E-015/M-06-1501*, at 2, Table 1; Ex. 61, *Document Regarding Minnesota Power's Renewable Resources Rider and 2015 Renewable Factor in Docket No. E-015/M-14-962*, at 2: Table 1; *Evidentiary Hearing Transcript*, Vol. 1, 54:17-56:3.

("ALJ") to submit recommendations to the Minnesota Public Utilities Commission (the "Commission") that (1) ensure that the need criteria in Minnesota Statutes ("Minn. Stat.") 216B.243 and Minnesota Rules ("MINN. R.") 7849 are satisfied and (2) help alleviate the immediate financial pressure that those rate increases have placed on all ratepayers. While the solutions posed by LPI may be unprecedented in certificate of need proceedings, they are in no way "contrary to statute" or "inconsistent with the public interest" as Minnesota Power suggests. The Commission has the authority to implement all of LPI's recommendations and, given the equally unprecedented facts presented in this proceeding, the ALJ should recommend that the Commission find each of them to be reasonable, equitable, and in the public interest.[4]

To assist the ALJ in her review of the issues discussed herein, the topics addressed in this reply brief are set forth in the same order that they were presented in Sections II.B and II.C of LPI's initial brief,[5] Sections V.B. and V.C. of Minnesota Power's initial brief,[6] and Sections II.B. and II.C. of the Department's initial brief.[7]

II. ANALYSIS

A. Comparing the Costs of the Project and Energy Supplied by the Project to the Costs of a Reasonable Alternative is Critical to the Commission's Evaluation of the Application

In the Application, Minnesota Power identified only one "need" for the Project: to deliver the capacity and power contracted for under the 250 MW Power Purchase Agreement and associated Energy Exchange Agreement with Manitoba Hydro (the "250 MW Agreements").[8] The other purported "needs" identified in Section 2 of the Application are actually *consequences* of the Project, not *needs* that the Project is designed to address.[9] In fact, Minnesota Power

[4] Over the course of this proceeding, it has become clear that LPI's positions on certain key issues of cost control differ from those advocated by the Department of Commerce – Division of Energy Resources (the "Department"). Thus, to the extent that the Department purports to represent the best interests of ratepayers in this proceeding, the Department does not speak for LPI which represents approximately 50% of Minnesota Power's customers by revenue.

[5] LPI Brief at 3-10.

[6] Minnesota Power Brief at 57-76.

[7] Department Brief at 33-39.

[8] Application at 11.

[9] *See* Application at 11-13 (discussing "increasing service reliability," "the incorporation of substantial hydropower resources into its long-term power supply," taking advantage of a "wind-water 'synergy'," providing "significant benefits" to the Midcontinent Independent System Operator Corp., and establishing a "new connection to energy resources in Manitoba").

witness Mr. McMillan stated quite plainly during the evidentiary hearing that "If we weren't buying power from Manitoba Hydro, we wouldn't need the line."[10]

In analyzing a certificate of need application, the Commission is obligated to consider "the cost of the proposed facility and the cost of energy to be supplied by the proposed facility compared the costs of reasonable alternatives and the cost of energy that would be supplied by reasonable alternatives."[11] To LPI's knowledge, the Commission has never before been faced with (and no party has cited) a certificate of need application wherein the utility has proposed a transmission line to interconnect a large generation source and the cost of that line and the energy to be supplied by it are at virtual parity with the cost of a reasonable alternative and the energy to be supplied by that alternative. Given Minnesota Power's admission that the Project is needed only to deliver energy under the 250 MW Agreements, the Commission's analysis of the costs associated with a reasonable generation alternative becomes paramount.

1. A Hard Cap on Recoverable Project Costs is Reasonable and Necessary Given the Unique Circumstances Presented by the Project

No party has disputed LPI witness Lane Kollen's testimony that there is little difference in projected costs between the 250 MW Agreements and a gas-fired combined-cycle generation unit,[12] which Minnesota Power identified as "the only reasonable generation alternative."[13] To LPI's knowledge, the Commission has never been asked to approve a certificate of need application where the cost of the proposed project was so close to the reasonable alternative. Of the fourteen transmission certificate of need dockets cited by Minnesota Power in its initial brief,[14] only four dealt with transmission lines designed specifically to provide generation outlet

[10] *Evidentiary Hearing Transcript*, Vol. 1, 45:25-46:1.

[11] MINN. R. 7849.0120(B)(2).

[12] Ex. 50, *Direct Testimony of Lane Kollen*, 7:5, 8. In its initial brief, Minnesota Power alleges that "Mr. Kollen's testimony ignores the substantial economic and environmental benefits Minnesota Power ratepayers will receive from the 133 MW [Renewable Optimization Agreements]." Minnesota Power Brief at 63. That statement misses the mark for two reasons. First, neither Minnesota Power nor any other party has quantified any "economic" or "environmental" benefits of the 133 MW ROAs that would mitigate the cost of the 250 MW Agreements or the Project. Second, and more importantly, Minnesota Power's need for the Project is founded only on the 250 MW Agreements. Thus any purported benefits of the 133 MW ROAs are necessarily beyond the scope of the need analysis that the ALJ and the Commission are undertaking in this proceeding.

[13] Ex. 43, *Direct Testimony of Allen S. Rudeck, Jr.*, 30:5.

[14] Minnesota Power Brief at 65-67.

capacity;[15] only two of those four were being developed to interconnect an <u>identified</u> generation source;[16] and in only one of those two was rate recovery an issue.[17] In every case cited by Minnesota Power where alternative generation was evaluated, the cost of that generation was substantially more expensive than the proposed transmission line:

- In Docket No. ET-2, E-015/TL-05-867, the generation alternatives for the Tower and Badoura transmission lines would have cost approximately 23% and 65% more, respectively, than the transmission lines.[18]
- In Docket No. ET-2/TL-06-367, the diesel generation alternative would have been three times more expensive than Great River Energy's ("GRE") proposed Mud Lake-Wilson Lake transmission line.[19]
- In Docket No. E-017/CN-06-677, the diesel generation alternative to the 115-kV upgrade to the Appleton-Canby transmission line was variously estimated to cost between two and six times more than the proposed line.[20]

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[15] Docket Nos. E-017, ET-6131, ET-6130, ET-6144, ET-6135, ET-10/CN-05-619 (the "Big Stone 2 Project"); E-002/CN-08-992 (the "Pleasant Valley-Byron 161-kV Project"; IP-6838/CN-10-80 (the "Prairie Rose Project"); and ET-6675/CN-12-1053 (the "Minnesota-Iowa 345-kV Project").

[16] The Big Stone 2 Project and the Prairie Rose Project. The Pleasant Valley-Byron 161-kV Project was designed to provide interconnection capacity but the generation source(s) was not identified and no least-cost comparison with other generation was conducted. Similarly, the Minnesota-Iowa 345-kV Project was designed to provide generation outlet capacity in southern Minnesota and northern Iowa but no generation sources were identified and no least-cost comparison with other generation was conducted.

[17] The Big Stone 2 Project. The Prairie Rose Project included a wind project and associated 115-kV transmission line that would be owned by the project developer and not an investor-owned utility ("IOU"). Therefore, rate recovery was never an issue.

[18] The Tower line was estimated at $12.193 million. And the distributed generation alternative was 6 MW of diesel generation estimated at $14.993 million because it would only delay transmission additions. *Request for Certification of Transmission Facilities (Tower Project)*, Docket No. ET2, E015/TL-05-867, BIENNIAL TRANSMISSION PROJECTS REPORT, CERTIFICATION OF A HIGH-VOLTAGE TRANSMISSION LINE, TOWER PROJECT at 4-2, 9-6 (Nov. 1, 2005). The Badoura line was estimated at $35.888 million and the distributed generation alternative was similarly estimated to cost $59.276 million. *Request for Certification of Transmission Facilities (Badoura Project)*, Docket No. ET-2, E-015/TL-05-867, BIENNIAL TRANSMISSION PROJECTS REPORT, CERTIFICATION OF A HIGH-VOLTAGE TRANSMISSION LINE, BADOURA PROJECT at 4-2, 9-8 (Nov. 1, 2005).

[19] The Mud Lake-Wilson Lake project was estimated at $8.3 million. The distributed generation alternative was a scalable diesel-fueled generator estimated to be $9.5 million for the first 10 MW and would only delay the need for the transmission project or an additional 10 MW of generation for two or three years. *See In the Matter of the Application for a Certificate of Need for the Mud Lake-Wilson Lake 115 kV High Voltage Transmission Line*, Docket No. ET-2/TL-06-367, APPLICATION at 3-12, 4-1 (July 28, 2006). The EA states that "[b]ased on cost estimates provided by GRE in its CON application, the diesel generation alternative is more than three times more expensive than the proposed transmission line while providing somewhat less reliability." *Id.*, ENVIRONMENTAL ASSESSMENT at 17 (Nov. 27, 2006).

[20] Otter Tail Power proposed to replace the existing 41.6 kV Appleton-Canby line with a 115 kV line. Project cost was estimated to be $2.6 million. *In the Matter of the Application for a Certificate of Need and a Route Permit for a 115 Kilovolt Transmission Line Between Appleton and Canby Substations*, Docket No. E-017/CN-06-677, APPLICATION at 2 (Sept. 7, 2006). The proposed generation alternative was 17 MW. Natural gas and wind

- In Docket No. E-002/CN-04-1176, a conservative assumption that only three 25 MW combustion gas turbines would have been required in place of the 115/161-kV system upgrade between Taylors Falls and Chisago County Substation reveals that the generation would have exceeded the upper-end of the cost estimate for the system upgrade by $25.8-$40.8 million.[21]
- In Docket No. ET-2, E-002 et al./CN-06-1115, Xcel and GRE assessed diesel peaking resources as an alternative to three CapX2020 345-kV transmission projects: the Twin Cities-LaCrosse line, the Twin Cities-Fargo line, and the Twin Cities-Brookings County line. The actual cost of generation necessary to address the identified needs was not discussed in Chapter 7 of the companies' application. However, the cost of single-cycle peaking units necessary to address the forecasted need in the Rochester and Winona/LaCrosse areas alone was estimated at $608 million - almost twice as expensive as the proposed Twin Cities-LaCrosse project.[22]
- In Docket No. E-017, E-015, ET-6/CN-07-1222, the two generation alternatives to the proposed 230-kV transmission line from Bemidji to Grand Rapids, Minnesota- *i.e.*, diesel and natural gas- would have cost 39% and 100% more, respectively, than the transmission project itself.[23]

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were deemed to be not feasible to meet the need. *Id.* at 39-40. Otter Tail Power estimated that a diesel generation alternative would cost close to $10 million, *id.* at 40, and the Environmental Assessment estimated the cost at between $5.95 and $13.6 million, not including ongoing fuel costs. *Id.*, Environmental Assessment at 51 (Dec. 15, 2006). Thus, the generation alternative was 2 to 6 times more expensive than the proposed transmission line.

[21] As proposed, the 115/161 kV transmission system upgrade between Taylors Falls and Chisago County Substation would cost between $49.9 million and $64.2 million. *In the Matter of the Application for Certificates of Need for a 115/161 kV Transmission Line Between Chisago County Substation and the Minnesota Border at Taylors Falls*, Docket No. E-002/CN-04-1176, APPLICATION at 1.12 (Nov. 15, 2006). In comparison, three to four 25 to 40 MW generation units would have been required initially to reliably meet the projected peak power demand through 2015 without transmission improvements. Each 25 MW CGT was estimated to cost between $30-$35 million; and each 40 MW CGT was estimated at $40-$45 million. *Id.* at 4.20.

[22] The cost estimates were as follows: Twin Cities-LaCrosse, $330-$360 million; Twin Cities-Fargo, $390-$560 million; Twin Cities-Brookings, $600-$665 million. *In the Matter of the Application for Certificates of Need for Three 345-kV Transmission Line Projects with Associated System Connections*, Docket No. ET02, E-002/CN-06-1115, APPLICATION at 2.17 (Aug. 16, 2007). Xcel and Great River Energy assessed diesel peaking resources as an alternative but determined that the identified needs (community service reliability, generation outlet, and regional reliability) could not be met by such generation. *Id.* at 7.12-7.15.

[23] As proposed, the Bemidji to Grand Rapids line would cost $60.6 million. *In the Matter of the Application for a Certificate of Need for a 230-kV Transmission Line and Associated System Connections from Bemidji to Grand Rapids, Minnesota*, Docket No. E-017, E-015, ET-6/CN-07-1222, APPLICATION at 1 (Mar. 17, 2008). The project would not interconnect any particular generation resource. The application stated that at least 110 MW of dispatchable generation would be required at 11 sites to provide the redundancy necessary to ensure that

- In Docket No. E-002/CN-10-694, putting wind and solar resources aside (which were estimated to cost $370 million and $670 million, respectively), the peaking generation alternative to Xcel's Hiawatha Project would have been at least twice as expensive as the transmission lines themselves.[24]
- Finally, in Docket No. E-002/CN-11-826, the proposed 115-kV and 69-kV upgrade known as the Southwest Twin Cities Chaska Project was able to provide the same incremental load-serving capability as 40-50 MW of generators for half the cost.[25]

Even the Big Stone 2 Project - the only proposed transmission project designed to deliver energy and capacity from an identified generator that would be owned by an investor-owned utility (and therefore the only one directly analogous to the GNTL) - can be easily distinguished from the GNTL. Whereas the utilities sponsoring the Big Stone 2 Project dismissed all other potentially-viable generation alternatives because they were 24%-50% more expensive than the proposed 600 MW Big Stone 2 generating unit,[26] LPI has shown that the reasonable combined-cycle alternative identified by Minnesota Power would be on cost parity with the 250 MW Agreements.[27] The extensive list of Commission decisions cited by Minnesota Power and described in detail by LPI above therefore underscore the unique nature of the GNTL proposal.

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at least 76 MW would be available at all times. *Id.* at 56. The cost of meeting requirement with (1) diesel generators would be more than $84.5 million, and (2) natural gas would be approximately $121.5 million. *Id.* at 40.

[24] As proposed, Xcel's Hiawatha Project, consisting of two 115-kV transmission lines was estimated to cost $30-$43 million. *In the Matter of a Certificate of Need for Two 115 kV High Voltage Transmission Lines in the Midtown Area of South Minneapolis, Hennepin County,* Docket No. E002/CN-10-694, APPLICATION at 3 (Nov. 29, 2010). To achieve necessary reliability to address the 55 MW deficit in the Focused Study Area, Xcel stated that four 20 MW simple-cycle combustion turbines would be required at a cost of at least $86 million. *Id.* at 71-72.

[25] The Southwest Twin Cities Chaska Project was estimated to cost $18.2 million. *In the Matter of a Certificate of Need for the Upgrade of the Southwest Twin Cities (SWTC) Chaska Area 69 Kilovolt Transmission Line to 115 Kilovolt Capacity*, Docket No. E002/CN-11-826, APPLICATION at 4, 13 (May 15, 2012). Small generators would not be sufficient to provide comparable load-serving capability. 40-50 MW of generators would cost approximately $40-$50 million, where the proposed project would provide the same incremental load-serving capability at half the cost. *Id.* at 55-56.

[26] In their application for a certificate of need for the Big Stone 2 Project, the utilities dismissed wind generation because it would not achieve the baseload capacity objective; biomass because of fuel resources; IGCC because it had a 50% higher busbar cost for IOUs; combined-cycle gas generation because it had a 33% higher busbar cost for IOUs; and wind plus combined-cycle gas generation because it had a 24% higher cost. *In the Matter of an Application for a Certificate of Need for High Voltage Transmission Lines in Western Minnesota*, APPLICATION at 92-102 (Oct. 3, 2005).

[27] Ex. 50, *Direct Testimony of Lane Kollen*, 7:5, 8.

2. A Hard Cap on Recoverable Project Costs Would Not Be Contrary to Minnesota Law, is Appropriate for a Certificate of Need Proceeding, and Would Not Create Perverse Incentives That May Harm the Public Interest

In its initial brief, Minnesota Power alleges that "a 'hard cap' runs contrary to Minnesota law, is not appropriate as part of a CON approval, goes beyond prior Commission orders, and creates perverse incentives that may harm the public interest."[28] It is true that a hard cap would go "beyond prior Commission orders" because, as discussed in detail above, the Commission has never before adjudicated a case where the cost difference between the proposed project and a reasonable generation alternative was practically negligible. However, Minnesota law does not prevent the Commission from capping the cost of a transmission project in a certificate of need proceeding. Nor would a hard cap create perverse incentives that may harm the public interest.

Minnesota Power argues that "prohibiting recovery today of costs which may be prudently incurred in the future violates the fundamental ratemaking principles embodied in Minnesota Statutes."[29] That is simply not true. The task ultimately before the Commission in this proceeding is to approve or deny Minnesota Power's application for a certificate of need for the GNTL. Minnesota Power has characterized its need as the ability to deliver power from Manitoba to Minnesota under the 250 MW Agreements. The ALJ has been presented with undisputed data showing virtual cost parity between the Project and the only reasonable generation alternative to the energy to be delivered by the Project.[30] Moreover, Minnesota Power has included approximately $92 million of contingencies in its most recent cost estimate[31]- an estimate that has been revised upwards by $126.2 million since Minnesota Power filed its Application[32].

With near cost parity between the Project and the combined-cycle alternative, it is incumbent upon the ALJ and the Commission to protect ratepayers by preventing cost overruns. From a ratepayer standpoint, with $92 million of contingencies built into the cost estimate already, any cost that would exceed the cost of the combined-cycle alternative could not be

[28] Minnesota Power Brief at 60.

[29] *Id.* at 61-62.

[30] Ex. 50, *Direct Testimony of Lane Kollen*, 7:5, 8.

[31] Ex. 59; *see also Evidentiary Hearing Transcript*, Vol. 1, 34:1-18.

[32] Calculated by subtracting the midpoint of the cost estimate provided in the Application ($507.8 million) from the most recent cost estimate provided in the direct testimony of Minnesota Power witness Mr. Donohue ($634.0 million). *See* Ex. 50, *Direct Testimony of Lane Kollen*, 5:23-6:11, nn. 2, 4.

deemed reasonable or prudent in a rider or rate case proceeding. By setting a hard cap on Minnesota Power's recoverable Project costs, the Commission would be (a) acknowledging the very small difference in projected costs between the Project and the combined-cycle alternative, (b) approving shareholder protections for cost overruns in the form of the $92 million in contingencies built into the budget, and (c) limiting ratepayer liability for cost overruns in excess of those contingencies. The Commission would not be preventing recovery of costs which "may be prudently incurred in the future," as the Company suggests. Rather, by imposing a hard cap, the Commission would be saying that no cost above the cap could be reasonable or prudent for ratepayers to bear given the unique circumstances of this case. Neither the Department nor Minnesota Power offers a defensible position in response to LPI's ratepayer-centric argument.

LPI is at a loss to understand Minnesota Power's claim that a hard cap would send "perverse signals to utilities and encourage resource decisions that are not in the best interest of ratepayers."[33] Department witness Dr. Rakow provided no references to, or analysis of, any such argument in his direct, rebuttal, or surrebuttal testimony.[34] Furthermore, had this truly been a concern of Minnesota Power, Mr. McMillan could have testified to it in his direct, rebuttal, or surrebuttal testimony, which he did not. The sum total of the evidence before the ALJ and the Commission on this argument is captured in a brief exchange during the evidentiary hearing. In that exchange, the ALJ inquired as to whether Dr. Rakow analyzed his recommendations as being "in the interest of the general ratepayers"?[35] Dr. Rakow's response was that he did not need to analyze it "'cause I already knew what the answer was, which is that they are not in the ratepayers' interest and it's not relevant to the decision in this case."[36] In their initial briefs, Minnesota Power and the Department do nothing more than reiterate Dr. Rakow's opinions on the matter[37] and LPI respectfully requests that the ALJ and the Commission dismiss the argument as being without foundation or support in the record. In fact, as a regulated utility, Minnesota Power has the opportunity to earn a reasonable rate of return on its capital-intensive

[33] Minnesota Power Brief at 63 (emphasis removed); *see also* Department Brief at 34-35 ("[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. . . . . A hard cap on cost recovery does not achieve that goal and is not in the best interests of ratepayers") (citing *Evidentiary Hearing Transcript*, Vol. 2, at 92-94).

[34] *See Evidentiary Hearing Transcript*, Vol. 2, 96:14-19.

[35] *Id.* at 92:22-93:7.

[36] *Id.* at 93:8-11.

[37] Minnesota Power Brief at 63; Department Brief at 34-35.

investments. To assert that Minnesota Power (or any other utility) would not be incented by this opportunity simply because of a cost cap - a cost cap that includes an overall cost contingency in excess of 13% of the utility's estimated Project cost - is simply beyond the pale.

Equally unsettling is Mr. McMillan's testimony that (1) "it's not appropriate at this time and not fair ultimately to impose a [hard cap] . . . until we know exactly what we're up against" and (2) Minnesota Power's shareholders should not bear the cost if the contingencies prove insufficient.[38] The clear implication of his testimony is two-fold. First, because the actual Project cost is unknown, the Commission should not impose a hard cap and ratepayers (as opposed to shareholders) should bear the risk of Minnesota Power's cost overruns. Second, the testimony amounts to a concession that Minnesota Power is unsure whether the combined-cycle alternative is more or less cost-effective than the GNTL. On this point, Mr. McMillan's testimony is therefore consistent with Mr. Kollen's surrebuttal testimony, in which he states that:

> the GNTL project may not be economic or in the public interest if the cost exceeds the cap I propose. The cost cap is an effective means of incentivizing the Company to manage the cost of the project within the overall budget to ensure that customers actually receive the value promised by the application.[39]

Given the near cost parity of the Project to a combined-cycle alternative, it is unclear how the public interest would be served if the public was made to bear the cost overruns for a project that would not have been selected on a cost basis had those overruns been properly forecast.

3. The Soft Cap on Recoverable Project Costs Advocated by Minnesota Power and the Department Would Be an Insufficient and Inefficient Mechanism to Protect Ratepayers

Minnesota Power and the Department have suggested that a "soft cap" consistent with the Commission's orders on cost recovery for Minnesota Power's Boswell 4 retrofit and on the Minnesota-Iowa 345-kV Project would be appropriate in lieu of the hard cap advocated by LPI.**[40]** As an initial matter, despite its protestations, by arguing for a "soft cap" Minnesota Power concedes that cost recovery issues can (and LPI suggests in this proceeding should) be addressed

[38] *Id.*, Vol. 1, 44:8-17.
[39] Ex. 51, *Surrebuttal Testimony of Lane Kollen*, 11:21 – 12:4.
[40] Minnesota Power Brief at 59.

in the Commission's order on the Application. Furthermore, Minnesota Power conveniently ignores the genesis of the soft cap – *i.e.*, the Company's cost overruns on Boswell 3.

In 2006, Minnesota Power submitted a petition for approval of its Boswell 3 environmental improvement plan.[41] As part of its rider filing submitted in early 2007, Minnesota Power stated that it estimated the capital investments to be approximately $198.2 million, with annual operation and maintenance costs to be approximately $12.5 million.[42] On October 26, 2007, the Commission approved Minnesota Power's plan for Boswell 3 and the associated cost recovery rider.[43] Notably, the Commission declined to impose a soft cap, as proposed by the Minnesota Chamber of Commerce.[44] In 2008, as part of its 2009 rider petition associated with the Boswell 3 environmental improvement plan, Minnesota Power casually asserted that its initial estimate of $198.2 million was understated by approximately $40 million.[45] After significant pushback from LPI, Minnesota Power, LPI, and the Minnesota Chamber of Commerce entered into a stipulation that, *inter alia*, established a framework for the soft cap.[46] Given the significant effort and expense associated with obtaining a soft cap and reviewing the cost overrun in the Boswell 3 proceedings, LPI began to forcefully argue for a soft cap in similar proceedings.

The Commission has adopted this line of thinking, expressing support for cost caps in two recent transmission cost recovery rider proceedings, stating separately that "[h]olding the Company to its initial estimate is an <u>important tool to enforce fiscal discipline</u>," and the "imposition of <u>a cap protects the integrity of the certificate of need process</u>, in which it is critical that the cost estimates for the alternatives being compared are as reliable as possible. . . . [C]apping costs at the certificate of need levels is consistent with the Commission's actions in

[41] *In the Matter of Minnesota Power's Petition for Approval of its Boswell 3 Environmental Improvement Plan*, Docket No. E-015/M-06-1501, INITIAL PETITION (October 27, 2006).
[42] *In the Matter of Minnesota Power's Petition for Approval of its Boswell 3 Environmental Improvement Rider*, Docket No. E-015/M-06-1501, INITIAL PETITION (January 26, 2007).
[43] *Id*.
[44] *In the Matter of Minnesota Power's Petition for Approval of its Boswell 3 Environmental Improvement Plan and Boswell 3 Environmental Improvement Rider*, Docket No. E-015/M-06-1501, ORDER (October 26, 2007).
[45] *In the Matter of Minnesota Power's Petition for Approval of its Boswell 3 Environmental Improvement Rider*, Docket No. E-015/M-08-1108, INITIAL PETITION (September 18, 2008).
[46] *In the Matter of Minnesota Power's Petition for Approval of its Boswell 3 Environmental Improvement Rider*, Docket No. E-015/M-08-1108, STIPULATION (July 28, 2009).

similar cases involving other utilities' riders.[47] Unfortunately, a "soft cap" on recoverable Project costs in this proceeding would be an insufficient tool to enforce fiscal discipline and protect ratepayers. As discussed above, the Minnesota-Iowa 345-kV Project cited by the Company was designed to provide generation outlet capacity in southern Minnesota and northern Iowa but no generation sources were identified and ITC did not conduct a least-cost comparison against alternative generators.[48] Thus, the Commission imposed a cost recovery limitation with less information than the Commission has before it in this case. While a "soft cap" may be appropriate for transmission lines being constructed in anticipation of generation in the region, a hard cap is appropriate in the narrow circumstances where, as here, a transmission line is proposed to deliver energy and capacity from a defined generation source and the cost of that source is at parity with the proposed project.

Furthermore, a soft cap would be administratively inefficient. In a proceeding currently pending before the Commission and the Office of Administrative Hearings, Northern States Power Company, d/b/a/ Xcel Energy is seeking cost recovery for cost overruns on a project involving its Monticello nuclear generating facility.[49] In that case, the Department is suggesting disallowance of a portion of the cost overrun, arguing for a cost-effectiveness threshold based on a comparison between the actual cost of the Monticello project and the next least-cost alternative available at the time the Commission approved the Monticello project.[50] If Minnesota Power's cost estimate for the GNTL proves to be too low as it did in the Boswell 3 proceedings, and were the Department or another party, in response to such a cost overrun, to make the same argument that the Department made in the Monticello proceeding, the end result would effectively be the hard cap that LPI is advocating. LPI fails to understand how punting the discussion of a hard cap to a later time and docket would be an effective and efficient means of ensuring ratepayer

[47] Ex. 51, pp. 12-13 (Kollen Surrebuttal), citing Docket No. E-002/M-12-50, ORDER APPROVING 2012 TCR PROJECT ELIGIBILITY AND RIDER, CAPPING COSTS, AND MODIFYING 2011 TRACKER REPORT, at 4-5 (Feb. 7, 2014) (emphasis added) and Docket No. E-017/M-13-103, ORDER CAPPING COSTS, DENYING RIDER RECOVERY OF EXCESS COSTS, AND REQUIRING INCLUSION OF ALL MISO SCHEDULE 26 COSTS AND REVENUES IN TCR RIDER, at 3-5 (Mar. 10, 2014) (emphasis added), respectively.

[48] *Supra* n. 16.

[49] *In the Matter of a Commission Investigation into Xcel Energy's Monticello Life Cycle Management and Extended Power Uprate Project and Request for Recovery of Cost Overruns*, PUC Docket No. E-002/GR-13-754, OAH Docket No. 48-2500-31139.

[50] *In the Matter of a Commission Investigation into Xcel Energy's Monticello Life Cycle Management and Extended Power Uprate Project and Request for Recovery of Cost Overruns*, PUC Docket No. E-002/GR-13-754, OAH Docket No. 48-2500-31139; Ex. 309, *SHAW DIRECT* at 20-33.

protection, especially when all relevant information is presently known to the ALJ and the Commission and undisputed by the parties.

B. <u>The Commission Has Discretion to Accept LPI's Cost Recovery and Cost Allocation Recommendations</u>

In addition to imposing a hard cap on recoverable Project costs, LPI maintains that the ALJ should recommend that the Commission: (1) condition any grant of the Application upon approval of the 133 MW Renewable Optimization Agreements to ensure cost recovery from Minnesota Power's ratepayers is limited to the 28.3% of projected Project costs as promised by Minnesota Power; (2) direct Minnesota Power to accrue allowance for funds used during construction ("AFUDC") rather than permit it to seek current recovery of construction work in progress ("CWIP") charges; (3) authorize ratemaking recovery through a rider as opposed to base rates; and (4) allocate the rate increase to customer classes based on base revenues excluding fuel and other riders. Minnesota Power and the Department have accepted LPI's first recommended condition.[51] The other three conditions remain in dispute.

Minnesota Power argues in its initial brief that none of the Commission's orders in the fourteen certificate of need proceedings it cites includes the cost recovery and cost allocation conditions that LPI is seeking.[52] However, LPI's review of those cases revealed no requests for the Commission to consider such conditions. There is a difference between relying on precedent wherein the relief sought was affirmatively denied and relying on precedent wherein such relief was not granted because it was never requested. LPI notes that Minnesota Power is doing the latter. The Company argues that the Commission has not ordered such conditions in the past, so it should not start now. LPI's response is simple: while the cited orders may be useful illustrations of what the Commission has not done, the orders do not support the Company's argument for rejecting Mr. Kollen's recommendations.

Finally, before discussing the three of Mr. Kollen's recommendations that remain in dispute, LPI is forced to address an assertion Minnesota Power raises for the first time in its initial brief. With respect to those recommendations, Minnesota Power suggests that "[p]erhaps

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[51] Ex. 35, *Rebuttal Testimony of David J. McMillan*, at 10:1-3; Ex. 55, *Rebuttal Testimony of Steve Rakow*, at 2:1.

[52] Minnesota Power Brief at 65.

Mr. Kollen offers these recommendations because, despite his substantial rate case, cost allocation and cost recovery testimony experience, a review of his resume fails to reveal a single CON proceeding in which he has participated."[53] That argument is short-sighted and out-of-time.

The ALJ's First Prehearing Order states clearly that "[e]xcept for good cause shown, objections by any party as to the qualifications of a witness or the admissibility of any portion of a witness' prefiled testimony are waived unless the objecting party states its objection by motion made to the Administrative Law Judge, no later than 4:30 p.m. on November 10, 2014."[54] The Company did not establish good cause for its objection (if, in fact, the statement qualifies as one) and it was clearly submitted out of time. Furthermore, Minnesota Power did not, in discovery or written testimony, question Mr. Kollen's experience. Nor did the Company cross-examine Mr. Kollen on his experience during the evidentiary hearing. Instead, Minnesota Power makes a blanket and unsupported allegation regarding Mr. Kollen's experience in its initial brief based on what appears to be a cursory review of one of the schedules attached to his direct testimony. Notwithstanding the language set forth in the First Prehearing Order, and out of an abundance of caution, LPI offers the Affidavit of Lane Kollen, attached hereto as Appendix A, in response to Minnesota Power's comment. Mr. Kollen's affidavit soundly refutes any allegation that he is not qualified to provide testimony and recommendations with respect to Minnesota Power's Application. Indeed, the fact that Mr. Kollen is participating in this proceeding on behalf of LPI speaks to the unique circumstances surrounding the GNTL, including the unprecedented cost parity between the 250 MW Agreements and an alternative generation source. It is for these reasons that LPI engaged Mr. Kollen's expertise and the ALJ and the Commission should seriously consider his testimony.

[53] Minnesota Power Brief at 64.
[54] FIRST PREHEARING ORDER at 9, ¶ 26 (Jan. 29, 2014).

1. Directing Minnesota Power to Accrue AFUDC Would Be Consistent With Minnesota Law and Would Not Harm Minnesota Power or its Customers

a. The Commission Has Discretion Under Minnesota Law to Require Minnesota Power to Accrue AFUDC

Minnesota Power's framing of the language of Minn. Stat. § 216B.16, subd. 7b(b)(5) is disingenuous and misleading.[55] The statute is permissive. The Department acknowledged that in its initial brief[56] and Minnesota Power witness Mr. McMillan acknowledged that in his testimony.[57] Nowhere did the legislature "direct" the Commission to do anything with respect to AFUDC or CWIP. Rather, the statute states plainly that the Commission has discretion to approve, reject, or modify any request for current recovery of CWIP:

> "Subd. 7b. Transmission cost adjustment. . . .
>
> (b) Upon filing by a public utility or utilities providing transmission service, the commission may approve, reject, or modify, after notice and comment, a tariff that: . . .
>
> (5) provides a current return on construction work in progress, provided that recovery from Minnesota retail customers for the allowance for funds used during construction is not sought through any other mechanism."

Minnesota Power also characterizes AFUDC treatment as "[t]hat older paradigm," ignoring the fact that accruing AFUDC and recovering through base rates is the default method for recovering construction costs and current recovery of CWIP can only be achieved in a transmission cost recovery ("TCR") rider, and then only at the discretion of the Commission. While the Department "is not aware of any instances where the Commission has denied current recovery of a return on CWIP,"[58] LPI is not aware of any instance in which current recovery of CWIP was challenged. The legislature clearly understood that current recovery of CWIP would not be appropriate in all cases and LPI posits that it would not be the appropriate method for cost recovery in this case.

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[55] *See* Minnesota Power Brief at 68-69 (omitting permissive language when quoting Minn. Stat. § 216B.16, subd. 7b(b)(5) and stating that "[g]iven the clear direction from the Legislature, the Commission has consistently approved transmission cost recovery ("TCR") filings that provide for "a current return on construction work in progress") (emphasis added).

[56] Department Brief at 36.

[57] *Evidentiary Hearing Transcript*, Vol. 1, 45:9-13.

[58] Department Brief at 36.

b. Current Recovery of CWIP By Minnesota Power Has Not Been Challenged Until Now

Minnesota Power and the Department emphasize Mr. Johnson's testimony that it would be "a significant departure from past precedent" if the Commission was to deny a request from Minnesota Power for current recovery of CWIP.[59] The Company goes on to cite four past TCR rider proceedings[60] as precedent for its argument that the Commission has "a consistent practice" of allowing the Company to receive current recovery of CWIP from its ratepayers.[61] However, no petition by Minnesota Power for current recovery of CWIP has ever been challenged. Moreover, while Minnesota Power is quick to point out that none of the Commission's orders on certificates of need since 2005 has included a condition related to TCR rider recovery,[62] (1) LPI is not aware of any case in which such a condition was deliberated by the Commission and (2) neither Minnesota Power nor the Department has cited any statute or rule obligating the Commission to deny such a condition. Thus, the facts of this case are unique and the limited precedent cited by Minnesota Power should not dictate the Commission's actions.

In his direct testimony, LPI witness Mr. Kollen provided the first reasoned analysis challenging the appropriateness of Minnesota Power's current recovery of CWIP.[63] In that analysis he posited seven reasons why ratepayers should be allowed to defer payment to Minnesota Power through the accrual of AFUDC. First, the AFUDC approach is consistent with Generally Accepted Accounting Principles (GAAP).[64] Second, it is consistent with the regulatory notion that ratepayers should not be responsible to bear a utility's costs until and asset is used and useful in providing service.[65] Third, it is consistent with the regulatory concept of generational equity - that is, that customers who use or benefit from an asset should be responsible for paying for that asset.[66] Fourth, costs of construction do not have a large immediate impact on customers rates.[67] Fifth, accrual of AFUDC on the 28.3% would match

[59] Minnesota Power Brief at 69.

[60] Docket Nos. E-015/M-07-965, E-015/M-08-1176, E-015/M-10-799, E-015/M-11-695. *See* Minnesota Power Brief at nn. 271, 274-276.

[61] Minnesota Power Brief at 70.

[62] Minnesota Power Brief at 71.

[63] Ex. 50, *Direct Testimony of Lane Kollen*, 21-22.

[64] *Id.* at 21:6-14.

[65] *Id*. at 21:15-18

[66] *Id*. at 21:19-22.

[67] *Id*. at 21:23-22:1.

Minnesota Power's accrual of the 17.7% under its 133 MW Energy Sale Agreement with Manitoba Hydro.[68] Stated differently, if Minnesota Power uses the current recovery method, it discriminates against its own ratepayers by allowing Manitoba Hydro to "pay later" while requiring its own ratepayers to "pay now" for current recovery. Sixth, there is no evidence in the record to demonstrate that a current return is necessary for Minnesota Power to bolster or retain its financial health.[69] Finally, the Commission is not obligated to allow for current recovery under any State law, including section 216B.16 of the Minnesota Statutes. LPI, which represents approximately 50% of Minnesota Power's customer base by revenue, believes that these reasons support its position that the Commission should direct Minnesota Power to use the AFUDC approach.

The inequity that would befall Minnesota Power's ratepayers if the utility was permitted current recovery of CWIP is worth special emphasis in this case. Minnesota Power has not proposed current recovery of CWIP from Manitoba Hydro.[70] "The arrangement with Manitoba Hydro is [that] they'll start to make a must take pay[ments] to us when they start to sell us energy under the 133 MW [Renewable Optimization Agreements]. . . . And I appreciate that 'cause they're not selling us any energy until 2020. So making a payment to us now is not something that commercially they wanted to agree with."[71] Thus, on one hand Minnesota Power supports charging its customers current recovery on CWIP for its ownership percentage *before* the Project is placed in service an; but on the other hand the Company is proposing to accrue AFUDC on Manitoba Hydro's ownership percentage until *after* the Project is placed in service. Such a result would be inequitable and to the detriment of Minnesota Power's customers.

c. Minnesota Power Has Not Demonstrated that Accruing AFUDC Would Harm Customers or Minnesota Power

The first argument that Minnesota Power makes in support of a current return on CWIP is that accruing AFUDC will cost ratepayers more. Minnesota Power asserts plainly that "it cannot be debated that mandating AFUDC treatment of construction costs will increase the *total cost* of

[68] *Id*. at 22:3-7.
[69] *Id*. at 22:8-9.
[70] *Evidentiary Hearing Transcript*, Vol. 1, 66:8-22.
[71] *Evidentiary Hearing Transcript*, Vol. 1, 67:14-68:2.

the Project to ratepayers."[72] While the *total cost* of the Project will increase so long as the economy experiences inflation, neither Minnesota Power nor the Department offered any evidence that would suggest such an increase would harm ratepayers. The Department stated the issue fairly succinctly in its initial brief:

> 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. This fact, however, does not necessarily result in a benefit to ratepayers because <u>annual revenue requirements would be significantly higher during the construction phase of the Project due to the current return on CWIP</u>. 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. But, in the end, precluding a current return on CWIP would delay cost recovery until a project is in service, which would increase the total overall revenue requirements. <u>Such a delay may or may not result in a detriment to ratepayers</u>.[73]

However, Minnesota Power's attempt to focus on total cost is nothing more than a smokescreen clouding the real issue: whether, *on a net present value basis*, ratepayers would pay more under AFUDC or current recovery of CWIP. This proceeding is chock-full of debate on CWIP vs. AFUDC[74] and the parties seem to agree with LPI on a few things. Minnesota Power witness Mr. McMillan acknowledged that Minnesota Power will fully recover its costs under either a current return on CWIP or an AFUDC approach.[75] And both Minnesota Power and Department witness Mr. Johnson concede that, on a net present value basis, it is unclear whether ratepayers would pay more under one or the other.[76] While Minnesota Power continues to tout

[72] Minnesota Power Brief at 71(emphasis added); *see also* Ex. 57, *Mark A. Johnson Surrebuttal Testimony*, 7:1-24..

[73] Department Brief at 36 (internal citations omitted).

[74] *See, e.g.*, Ex. 50 *Direct Testimony of Lane Kollen*, 19:19-20:12; Ex. 35 *Rebuttal Testimony and Exhibits of David J. McMillan*, 13; Ex. 57 *Mark A. Johnson Surrebuttal Testimony* 7-9; *Evidentiary Hearing Transcript*, Vol. 1, 46:3-47:21; *Evidentiary Hearing Transcript*, Vol. 2, 68:4-72:6.

[75] *Evidentiary Hearing Transcript*, Vol. 1, 46:4-10.

[76] *Id.*, Vol. 2, 78:5-9; Minnesota Power Brief at 71 ("Given the timing delay in recovery under these two methods, a number of assumptions would be necessary to draw any definitive conclusion as to the net impact on ratepayers"); *see also* Department Brief at 37 ("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 costs for ratepayers") (internal citation omitted).

the "benefits" of CWIP to ratepayers that it espoused in its 2010 TCR rider docket,[77] the testimony presented in this case shows that those assertions remain bald and unsubstantiated.

The second argument that Minnesota Power makes in support of a current return on CWIP is that "mandating AFUDC treatment . . . creates the possibility of 'rate shock' to customers once the Project is placed in service."[78] However, Minnesota Power's recent spate of rate increases has produced a "rate shock" all its own, for all ratepayers. LPI understands the result of deferring costs by accruing AFUDC and believes it is in ratepayers' best interest to do so. Given the choice, LPI would prefer to reduce its current rate shock and "pay Minnesota Power later."

Finally, Minnesota Power argues that "AFUDC treatment of Project construction costs would severely harm Minnesota Power's cash flow, which in turn can lower the Company's financial ratings and impose additional costs on ratepayers due to higher cost of capital."[79] However, Mr. McMillan acknowledged during the evidentiary hearing that Minnesota Power has not put anything into the record to support the notion that the AFUDC approach would hurt the utility from a financial perspective.[80] Thus, not only has Minnesota Power not demonstrated that accruing AFUDC would harm customers, it has not demonstrated that it would harm Minnesota Power either. Meanwhile, no party has rebutted the seven justifications for requiring Minnesota Power to accrue AFUDC posited by Mr. Kollen. Minn. Stat. § 216B.16, subd. 7b(b)(5) gives the Commission the discretion to permit or deny current recovery on CWIP. Because Minnesota Power has not shown that any party would be harmed if the Commission required it to accrue AFUDC and LPI, which represents over 50% of Minnesota Power's customers by revenue, has provided a reasoned analysis challenging the appropriateness of current recovery on CWIP in this case, LPI respectfully requests that the ALJ recommend that the Commission direct Minnesota Power to accrue AFUDC for the Project.

[77] *In the Matter of Minnesota Power's Petition for the 2010 Approval of a Transmission Cost Recovery Rider under Minn. Stat. § 216B.16, subd. 7b*, Petition for Approval (2010 Transmission Factor) at 7, 21-22 (July 15, 2010) (arguing that (1) "current recovery of CWIP through the transmission rider . . . is better for Minnesota Power's customers" and (2) "[c]urrent cost recovery with the use of CWIP versus rate base recovery later with AFUDC reduces costs for customers").

[78] Minnesota Power Brief at 71.

[79] *Id.* at 72 (citing *Evidentiary Hearing Transcript*, Vol. 1, 76-80).

[80] *Evidentiary Hearing Transcript*, Vol. 1, 70:2-7.

2. Directing Minnesota Power to Recover Project Costs Through the TCR Rider Would Maximize Transparency in Determining Its Revenue Requirement

Over the course of this proceeding, LPI has advocated that the Project costs should be recovered through a rate rider, such as Minnesota Power's TCR rider, rather than through base rates. Minnesota Power and the Department argued in their initial briefs that mandating recovery through a rider would not be appropriate because (1) Minn. Stat. § 216B.16, subd. 7b(b)(9) does not require it, (2) better ratemaking outcomes may be achieved through a general rate case, and (3) to do so would pre-determine rate recovery of the Project over the next 55 years.[81] However, LPI's proposal for rider recovery should not be interpreted as a proposal to limit the Commission's options with respect to rate recovery. The foundation for LPI's proposal is that the Commission should seek to maximize transparency by establishing one venue for discussing the costs and revenues related to the Project.[82] The combination of contractual and other arrangements under which Minnesota Power will receive revenue, including the "must-take fee" under the 133 MW Renewable Optimization Agreements with Manitoba Hydro and possible MISO revenue credits, are unique to the GNTL and have the potential to create inefficiencies in attempting to track the multiple inputs to the revenue requirement simultaneously in multiple dockets. To address the concern raised in Mr. Johnson's surrebuttal testimony that recovering only through a TCR rider "would essentially be pre-determining rate recovery of the Project over the next 55 years,"[83] LPI has two responses. First, mandating recovery of the GNTL-related costs in a rider does not pre-determine rate recovery. Instead, it predetermines the docket in which rate recovery is addressed. Second, LPI is willing to consider a recommendation from the ALJ that the Commission require rider recovery for the first five years following the date the Project is placed in service, after which the Commission can reevaluate its decision.

[81] Minnesota Power Brief at 73-74; Department Brief at 38.

[82] Ex. 50, *Direct Testimony of Lane Kollen*, 25:8-10 ("[A]lthough it is conceivable that certain credits could flow through the fuel and purchased energy adjustment rider, it would be more transparent if GNTL costs and credits were addressed in the transmission cost recovery rider").

[83] Ex. 57, *Surrebuttal Testimony of Mark A. Johnson*, 10:25-26.

3. Allocating Rate Increases to Partially Remedy Existing Interclass Subsidies Currently Provided by the Large Power Class Would Not Be Contrary to Minnesota Law

Finally, LPI advocates the allocation of rate increases associated with the Project to customer classes based on base revenues, excluding fuel and other riders in order to partially remedy existing interclass subsidies currently provided by the large power class.[84] In its initial briefs, Minnesota Power and the Department argue simply that cost allocation matters are addressed in cost recovery or rate case proceedings.[85] Minnesota Power also argues that its customers have not been provided appropriate notice to weigh-in on cost allocation issues in this proceeding.[86] LPI is not sure of the direction of these arguments. Cost and cost allocation are definitely part of this proceeding - Minnesota Power's own application sets forth a table estimating an increase of 3.29% to residential customers, 3.05% to general service customers, 3.46% to large light and power customers, and 4.93% to large power customers.[87] If the rate impact of the GNTL were irrelevant or unimportant for the Commission to consider, then LPI fails to understand why this information was included in the Application. The answer, of course, is that cost of the proposed facility and the energy to be supplied by it, compared to reasonable alternatives, is required information for a complete certificate of need application. To be sure, the Cost and Service Characteristics section of the Application, which is section 4.3 and where the table referenced by Mr. Kollen is found, is cited in Minnesota Power's Completeness Checklist for MINN. R. 7849.0120 B.2. under the heading "Cost of facility and of its energy compared to reasonable alternatives."[88]

Furthermore, as the ALJ noted during the evidentiary hearing, LPI represents roughly 50% of Minnesota Power's customers by revenue.[89] This interest, when combined with the Department's participation, should be deemed sufficient for purposes of engaging in cost-allocation discussions. After all, LPI is unaware of any recent rider-recovery petitions in which Minnesota Power served each of its estimated 140,000 customers with notice of increased

[84] Ex. 50, *Direct Testimony of Lane Kollen*, 27:17-18.
[85] Minnesota Power Brief at 74; Department Brief at 39.
[86] Minnesota Power Brief at 75 ("The Notice Plan approved by the Commission required notice 'to landowners reasonably likely to be affected by the proposed transmission line,' not to Minnesota Power's 140,000 customers living outside the area proposed for the Project").
[87] Ex. 50, *Direct Testimony of Lane Kollen*, 25:17-19 (citing *Application* at 30).
[88] *The Application*, at xvi.
[89] *Evidentiary Hearing Transcript*, Vol. 2, 72:21-73:8.

rates.[90] Given that the regular participating parties are represented in this proceeding, it is administratively efficient to address cost-allocation issues now to avoid parties from engaging in the same discussions at a later date. LPI therefore continues to respectfully request that the ALJ recommend that the Commission direct Minnesota Power to allocate the rate increases associated with the Project to customer classes based on base revenues, excluding fuel and other riders.

[90] *See, e.g.*, Docket No. E015/M-14-990 (notice of Minnesota Power petition for approval of its 2015 Boswell Unit 4 Emission Reduction Factor served only on general service list).

III. CONCLUSION

LPI continues to have significant concerns regarding the ever-increasing costs of the Project and how Minnesota Power should be permitted to recover those costs from ratepayers. LPI stands by the five recommendations that it has advocated since the beginning of this proceeding as reasonable, prudent and administratively efficient solutions to those concerns. Thus, LPI respectfully requests the ALJ to recommend that the Commission: (1) impose a hard cap on Project investment; (2) make any granting of the Application contingent upon approval of the ROAs; (3) direct Minnesota Power to use the AFUDC approach; (4) authorize Project cost recovery through a rate rider for a minimum of five years after the Project is placed in service; and (5) allocate the rate increases associated with the Project to customer classes based on base revenues, excluding fuel and other riders.

Dated: January 16, 2015

Respectfully submitted,

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Attorneys for Large Power Intervenors

APPENDIX A
Affidavit of Lane Kollen

(Follows this page.)

STATE OF MINNESOTA
BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
100 Washington Square, Suite 1700
Minneapolis, MN 55401-2138

FOR THE PUBLIC UTILITIES COMMISSION OF THE STATE OF MINNESOTA
121 Seventh Plaza East, Suite 350
St. Paul, MN 55101-2147

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

PUC Docket No. E-015/CN-12-1163
OAH Docket No. 65-2500-31196

AFFIDAVIT OF LANE KOLLEN

I, Lane Kollen, being first duly sworn upon oath, declare as follows:

1. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

2. I have been active participant in the utility industry for more than thirty years, initially as an employee of The Toledo Edison Company from 1976 to 1983 and thereafter as a consultant in the industry since 1983.

3. I have testified as an expert witness on planning, ratemaking, accounting, finance, and tax issues in proceedings before regulatory commissions and courts at the federal and state levels on nearly two hundred occasions, including proceedings before the Minnesota Public Utilities Commission (the "Commission").

4. I understand from counsel to the Large Power Intervenors in the Commission docket captioned above that Minnesota Power has made the following allegation in its initial post-hearing brief with respect to my credentials and certain cost recovery and cost allocation recommendations that I made in my Direct Testimony: "Perhaps Mr. Kollen offers these

recommendations because, despite his substantial rate case, cost allocation and cost recovery testimony experience, a review of his resume fails to reveal a single [certificate of need] proceeding in which he has participated." Minnesota Power Brief at 64.

5. In response to that allegation, and in order to assist the Administrative Law Judge and the Commission in their evaluation of the evidence provided by the parties, I make the following statements.

6. The qualifications and regulatory appearances detailed in Appendix A to my Direct Testimony are true and correct. However, Appendix A to my Direct Testimony does not include every project that I have worked on during my career and does not reflect all of the extensive work I have done on generation and resource planning that has not resulted in the filing of expert testimony.

7. At Toledo Edison Company, I was in charge of financial planning and a member of the management and technical team that evaluated all generation and transmission resources and monitored the schedule and cost of all generation and transmission projects that were under construction.

8. As a consultant at Energy Management Associates, I advised dozens of utilities on resource planning, including Cleveland Electric Illuminating, Duquesne Light, Middle South Utilities (Entergy), Atlantic City Electric, Tampa Electric, and Florida Power & Light Company, among others. A certificate of need proceeding is merely the culmination of this resource planning process.

9. I have conducted multiple prudence audits of new generation and transmission facilities and the alternatives that were, or should have been, considered. One example is the

prudence audit of the River Bend generating unit, for which I filed multiple testimonies- each of which is listed on Appendix A to my Direct Testimony.

10. I have participated in and filed expert testimony in numerous resource planning and certificate proceedings, which, in fact, are listed in Appendix A to my Direct Testimony. For example, in May 1994, I filed expert testimony in a Louisiana Power & Light Company integrated resource planning proceeding. In March 2002, I filed expert testimony regarding nuclear life extension. In August 2008, I filed expert testimony on Wisconsin Power & Light Company's proposed new generating resources. In June 2011, I filed expert testimony on the certification cost and other conditions associated with Georgia Power Company's proposed Vogtle 3 and 4 nuclear generating units. In March 2011, I filed expert testimony in a Kentucky Power Company certification proceeding for environmental retrofits. In April 2013, I filed expert testimony in a Kentucky Power Company proceeding addressing resource alternatives. .

11. Finally, I am presently advising the Louisiana Public Service Commission on integrated resource planning issues (including new generation, demand-side management, and customer-applied resources) involving several utilities.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

DATED: January 16, 2015.

Lane Kollen

This certificate is attached to a 3-page document entitled **AFFIDAVIT OF LANE KOLLEN** and dated January 16, 2015.

STATE OF GEORGIA)
) ss
COUNTY OF FULTON)

This record was acknowledged before me on January 16, 2015, by Lane Kollen, who proved to me on the basis of satisfactory evidence to be the person who appeared before me.

X Personally Known
or
______ Produced Identification
Type of ID ____________________

Leah J. Wellborn
Signature of notary public

Leah J. Wellborn
(Name of notary, typed, stamped or printed)
Notary Public State of Georgia

LEAH J WELLBORN
MY COMMISSION EXPIRES
NOTARY PUBLIC
MAY 28, 2017
FULTON COUNTY, GEORGIA
Stamp/Seal

My commission expires: May 28, 2017

PUBLIC DOCUMENT-
TRADE SECRET DATA REMOVED

BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, Minnesota 55101

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

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

OAH Docket No. 60-2500-30782
MPUC Docket No. E-015/CN-12-1163

LARGE POWER INTERVENORS' COMMENTS TO
MINNESOTA POWER PROPOSED FINDINGS OF FACT,
CONCLUSIONS OF LAW AND RECOMMENDATION

December 19, 2014

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OAH Docket No. 60-2500-30782
MPUC Docket No. E-015/CN-12-1163

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE PUBLIC UTILITIES COMMISSION

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

FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION

An evidentiary hearing was held before Administrative Law Judge ("ALJ") Ann O'Reilly beginning on November 12, 2014 at 9:30 a.m. in the Large Hearing Room at the offices of the Minnesota Public Utilities Commission ("Commission" or "MPUC") in St. Paul, Minnesota, and continuing on November 14, 2014. Public Hearings were held in: Roseau and Baudette, Minnesota on October 7, 2014; Littlefork, Minnesota on October 8, 2014; Kelliher and Bigfork, Minnesota on October 14, 2014 and Grand Rapids, Minnesota on October 15, 2014. Written public comments were received until December 3, 2014.

Post hearing briefs were filed on December 19, 2014, and responsive briefs were filed on January 16, 2015.

The following appearances were made:

David Moeller, Senior Attorney, Minnesota Power, 30 West Superior Street, Duluth, Minnesota 55802 and Eric F. Swanson, Winthrop & Weinstine, P.A., 225 South Sixth Street, Suite 3500, Minneapolis, Minnesota 55402, appeared on behalf of Minnesota Power, an operating division of ALLETE, Inc. ("Minnesota Power" or "Company").

Peter Madsen, Assistant Attorneys General, 1800 Bremer Tower, 445 Minnesota Street, St. Paul, Minnesota 55101, appeared on behalf of the Department of Commerce Division of Energy Resources ("Department" or "DOC-DER").

Linda Jensen, Assistant Attorney General, 1800 Bremer Tower, 445 Minnesota Street, St. Paul, Minnesota 55101, appeared on behalf of the Department of Commerce Energy Environment Review and Analysis ("DOC-EERA").

Andrew Moratzka, 33 South Sixth Street, Suite 4200, Minneapolis, Minnesota 55402 and Chad Marriott, 900 SW Fifth Avenue, Suite 2600, Portland, Oregon 97204, Stoel Rives LLP, appeared on behalf of the Large Power Intervenors ("LPI").

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Carol Overland, Legalectric, Inc., 1110 West Avenue, Red Wing, Minnesota 55066, appeared for Residents and Ratepayers Against Not-so-Great-Northern Transmission ("RRANT")

Commission Staff Michael Kaluzniak appeared for the Commission.

NOTICE

Notice is hereby given that, pursuant to Minn. Stat. § 14.61, and the Rules of Practice of the Minnesota Public Utilities Commission and the Office of Administrative Hearings, exceptions to this Report, if any, by any party adversely affected must be filed according to the schedule which the Commission will announce. Exceptions must be specific and stated and numbered separately. Proposed Findings of Fact, Conclusions, and Recommendations should be included, and copies thereof shall be served upon all parties. Oral argument before a majority of the Commission will be permitted to all parties adversely affected by the ALJ's recommendation who request such argument.

The Commission will make the final determination of the matter after the expiration of the period for filing exceptions as set forth above, or after oral argument, if such is requested and had in the matter.

Further notice is hereby given that the Commission may, at its own discretion, accept or reject the ALJ's recommendation and that said recommendation has no legal effect unless expressly adopted by the Commission as its final order.

STATEMENT OF ISSUES

1. Has Minnesota Power satisfied the requirements of Minn. Stat. § 216B.243 and the criteria of Minn. R. 7849.0120 and other applicable legal requirements for a Certificate of Need for the Great Northern Transmission Line?

~~1.~~2. Have parties to the proceeding raised other issues relevant to the application, and if so, what is the proper disposition of those issues?

SUMMARY OF RECOMMENDATIONS

The ALJ concludes that Minnesota Power has satisfied the criteria set forth in Minnesota law for a Certificate of Need ("CON") for the Great Northern Transmission Line and that the Commission should GRANT the CON, contingent upon a few qualifications raised by the parties to the proceeding, consistent with the Findings of Fact and Conclusions of Law below.

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Based on the information in the Certificate of Need Application ("CON Application"), the Environmental Report, the testimony at the public hearings and evidentiary hearing, written comments, exhibits received in this proceeding, and other evidence in the record, the ALJ makes the following:

FINDINGS OF FACT

I. APPLICANT AND OTHER PARTIES

1. Minnesota Power, the Applicant in this proceeding, provides retail electric service subject to the jurisdiction of the Commission. Minnesota Power is also a Transmission Owner in the Midcontinent Independent System Operator ("MISO"), subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC").

2. The DOC-DER is statutorily authorized to intervene in CON proceedings and to participate in Commission matters involving utility rates and the adequacy of utility services.

3. The DOC-EERA is not a party to this proceeding but prepared the Environmental Report for the Commission's consideration.

4. LPI, consists of several of Minnesota Power's largest retail customers, and includes ArcelorMittal USA (Minorca Mine); Boise, Inc.; Enbridge Energy, Limited Partnership; Hibbing Taconite Company; Mesabi Nugget Delaware, LLC; Verso Corporation (successor-in-interest to NewPage Corporation's Duluth Mill); PolyMet Mining, Inc.; Sappi Cloquet, LLC; UPM – Blandin Paper Company; USG Interiors, LLC; United States Steel Corporation (Keewatin Taconite and Minntac Mine); and United Taconite, LLC.

5. RRANT consists of potentially affected landowners, farmers, residents and ratepayers within the vicinity of the proposed Great Northern Transmission Line and in the service territory of Minnesota Power.

II. PROCEDURAL SUMMARY

A. Filings and Contested Case Hearing Process

6. On October 29, 2012, Minnesota Power 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. These were filed in anticipation of the Company's CON Application for a high-voltage transmission line project (the "Project").

7. On November 19, 2012, the Commission received comments on the notice plan from the DOC-DER and from Carol Overland.

8. Minnesota Power filed reply comments on its notice plan on December 10, 2012. The Company provided clarifying information and stated that it added two additional newspapers in Itasca County to its notice list based on requests it received at open house meetings it held to discuss the potential Project with the public.

9. On December 17, 2012, the DOC-DER filed comments on the Company's exemption request, recommending that the Commission approve it in part and deny it in part.

10. Minnesota Power filed reply comments on its exemption request on January 16, 2013, to address the DOC-DER comments.

11. On January 16, 2013, filing in her individual capacity as an interested person, Carol Overland filed comments recommending that the Company's exemption requests be denied.

12. On January 23, 2013, the DOC-DER filed additional comments on both the proposed notice plan and exemption request, recommending that the Commission approve both, as clarified and modified.

13. The Commission met to consider the notice plan and exemption request on January 31, 2013 and on February 28, 2013, the Commission issued its Order Approving Notice Plan, Granting Variance Request, and Approving Exemption Request.

14. As required by the notice plan, on August 5, 2013, Minnesota Power provided notice of the Project, its intent to file for a CON, and associated matters to landowners, stakeholders, government officials and elected representatives.[1]

15. On October 21, 2013, Minnesota Power filed its Application for a CON for the construction of the Great Northern High Voltage Transmission Line project in northern Minnesota.

16. On October 22, 2013, Minnesota Power filed additional materials related to Part 3 of Appendix O to its petition.

17. LPI filed comments on November 19, 2013, recommending that the Commission find the CON Application complete and refer the case for contested case proceedings.

[1] *See* Exhibit ("Ex.") 63.

18. On November 19, 2013, the DOC-DER filed comments stating that the CON Application was complete and recommending that the Commission refer the petition to the Office of Administrative Hearings for contested case proceedings.

19. On November 19, 2013, filing in her individual capacity as an interested person, Carol Overland filed comments recommending that the Commission refer the petition to the Office of Administrative Hearings for contested case proceedings.

20. On December 3, 2013, Minnesota Power filed reply comments.

21. The Commission met to consider the matter on December 19, 2013, and on January 8, 2014 issued its Order Accepting Filing, Varying Time Lines, and Notice and Order For Hearing, naming Minnesota Power and DOC-DER as parties.

22. On January 10, 2014, RRANT filed a Petition to Intervene.

23. On January ~~14~~16, 2014, LPI filed a Petition to Intervene.

24. On January 17, 2014, a Prehearing Conference was held in the Large Hearing Room at the MPUC.

25. On January 29, 2014, the ALJ issued the First Prehearing Order in this matter, establishing the procedural schedule and, as no objections were filed, granting the Petitions to Intervene of LPI and RRANT.

26. On August 8, 2014, Minnesota Power filed its Direct Testimony in this matter.

27. On September 19, 2014, DOC-DER and LPI filed their Direct Testimony.

28. On October 24, 2014, Minnesota Power and DOC-DER filed Rebuttal Testimony.

29. On November 7, 2014, Minnesota Power, DOC-DER and LPI filed Surrebuttal Testimony.

30. RRANT did not file testimony in this proceeding.

31. On November 12 and November 14, 2014, the ALJ presided over the contested case hearings in this matter.

32. On December 5, 2014, Minnesota Power, DOC-DER, LPI and RRANT ("Parties") submitted an Issues Matrix.

33. On December 19, 2014, ~~the Parties~~Minnesota Power, DOC-DER, and RRANT submitted Initial Briefs and Minnesota Power submitted its Proposed Findings of Fact, Conclusions of Law and Recommendation.

34. On December 22, 2014, LPI submitted its Initial Brief and a Notice of Motion and Motion for Extension of Time for Filing of Initial Brief.

~~33.~~35. On January 9, 2015, the ALJ issued the Order Granting Large Power Intervenors' Motion for Extension of Time for Filing of Initial Brief.

~~34.~~36. On January 16, 2015, the Parties submitted their Reply Briefs and DOC-DER, LPI and RRANT submitted their Proposed Findings of Fact, Conclusions of Law and Recommendation.

B. Environmental Review

~~35.~~37. The environmental review for this proceeding was conducted by DOC-EERA. DOC-EERA was not a party to the proceeding but acted in an advisory role on environmental matters related to the CON Application.

~~36.~~38. On January 15, 2014, DOC-EERA and Commission Staff issued the Notice of Public Information and Environmental Report Scoping Meetings.[2]

~~37.~~39. DOC-EERA and Commission Staff held Public Information and Environmental Report Scoping Meetings at the following locations on the dates indicated: Roseau Civic Center, Roseau, Minnesota on February 11, 2014; Baudette Ambulance Garage, Baudette, Minnesota on February 12, 2014; AmericInn, International Falls, Minnesota on February 13, 2014; Ralph Engelstad Arena, Thief River Falls, Minnesota on February 18, 2014; the Sanford Center, Bemidji, Minnesota on February 19, 2014; and Sawmill Inn, Grand Rapids, Minnesota on February 20, 2014.

~~38.~~40. At those hearings, approximately 90 people attended and approximately 20 people spoke on the record.[3] The Public Hearing Transcripts were received as Exhibit 2.

~~39.~~41. DOC-EERA also received 28 written comments regarding the Environmental Report Scoping, during the comment period, which was open until March 14, 2014.[4] The written comments were received as Exhibit 3.

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[2] Ex. 1 (Notice of Public Information and Environmental Report Scoping Meetings).
[3] Evidentiary Hearing Transcript Volume ("V.") 2, p. 13.
[4] V. 2, p. 13.

~~40.~~42. The comments received fell into three categories: comments directed exclusively at the route, which DOC-EERA forwarded to the Route Permit docket (E-015/TL-14-21); comments directed at both the route and need, which DOC-EERA forwarded to the route permit docket but also addressed in the current docket; and comments directed at need.[5]

~~41.~~43. On April 22, 2014, DOC-EERA issued its Scoping Decision for the Environmental Report.[6]

~~42.~~44. On July 14, 2014, DOC-EERA issued its Notice of Availability of Environmental Report[7] and the Environmental Report.[8] Notice of the Availability of the Environmental Report was also published in the Environmental Quality Board Monitor.[9]

C. Public Hearings and Comments

~~43.~~45. On September 9, 2014, the Commission issued its Notice of Public Hearing on the CON Application.

~~44.~~46. Seven public hearings were held, presided over by the ALJ, in the following locations and on the dates indicated: Roseau Civic Center, Roseau, Minnesota on October 7, 2014; Lake of the Woods School, Baudette, Minnesota on October 7, 2014; Littlefork Community Center, Littlefork, Minnesota on October 8, 2014; North Beltrami Community Center, Kelliher, Minnesota on October 14, 2014; Bigfork School Edge Center, Bigfork, Minnesota on October 15, 2014; and Timberlake Lodge, Grand Rapids, Minnesota on October 15, 2014.

~~45.~~47. Approximately 20 members of the public spoke at the public hearings, with the majority of the comments directed at routing questions. Commenters also asked questions of Minnesota Power related to the cost of the facility, its relationship to other Minnesota Power facilities and regarding Minnesota Power's contracts with Manitoba Hydro.

~~46.~~48. Public Comments were received by the public comment deadline of December 3, 2014, and were marked as Public Comment Exhibits A through P.

~~47.~~49. The only comments received from Minnesota residents, Public Comments A, B and E through I, all related to route permit issues.

5 V. 2, pp. 13-16.
6 Ex. 4.
7 Ex. 5.
8 Ex. 6.
9 Ex. 7.

~~48.~~50. Public Comments C and J are two copies of a letter submitted by the MISO and indicating that MISO considers the Project to be a result of "sound execution of MISO's collaborative Transmission Planning process" and that the Project is appropriate "to address system needs and opportunities."

~~49.~~51. Public Comment Exhibit D is a letter from a resident of Wisconsin addressing need and issues related to Manitoba Hydro.

~~50.~~52. Public Comment Exhibit K is a copy of correspondence from Minnesota Power attaching the FERC Order approving the Facilities Construction Agreement ("FCA") between Minnesota Power and Manitoba Hydro and also in the record as Exhibit 64.

~~51.~~53. Public Comment Exhibit L is a copy of correspondence from Canadian Ambassador to the United States Gary Doer to the United States Environmental Protection Agency discussing the Project and its ability to lower emissions related to Minnesota Power's energy supply portfolio.

~~52.~~54. Public Comment Exhibits M through O were filed by a resident of Arkansas and address need and MISO related issues.

III. THE PROJECT

A. Facilities

~~53.~~55. 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").[10]

~~54.~~56. At the time of the CON Application, Minnesota Power stated that the Project would provide at least 750 MW of transfer capability. However, subsequent analysis indicates that once completed, the Project will provide approximately 883 MW of transfer capability.[11]

~~55.~~57. Given the route alternatives as presented to date in the Route Permit proceeding, MPUC Docket No. E-015/TL-14-21, the 500 kV Line will be approximately 220 miles in length, and will be constructed on a 200 foot wide right of way likely in the

[10] Ex. 9, p. 24; Ex. 42, p. 3 (Winter Direct).
[11] Ex. 42, p. 3 (Winter Direct).

following Minnesota counties: Beltrami, Itasca, Koochiching, Lake of the Woods, and Roseau.[12]

~~56.~~58. The 500 kV Line will be part of a new 500 kV international transmission interconnection (the "500 kV Interconnection") between Manitoba and the United States. Manitoba Hydro will be constructing the Canadian portion of this new international interconnection.[13]

~~57.~~59. In addition to the transmission line, the Project includes expansion of the Blackberry Substation and a series compensation station, to be located near the midpoint of the combined Manitoba and United States transmission line.[14]

~~58.~~60. Minnesota Power anticipates using 3-conductor bundle 1192.5 kcmil Aluminum Steel Conductor Reinforced ("ASCR") "Bunting" with 18 inch sub-spacing as the phase conductor for the Project. This conductor is the same as that used on the existing Dorsey - Chisago 500 kV transmission line. Final conductor selection for the Project will be based on a conductor optimization study.[15]

~~59.~~61. Minnesota Power continues to evaluate several structure types and configurations of towers that will be used for the line, including a self-supporting lattice tower, a lattice guyed-V structure and a lattice guyed delta structure. Minnesota Power currently estimates approximately four to five structures per mile of line, with the type of structure in any given section of line dependent on land type and land use.[16]

B. Ownership and Financial Responsibility

~~60.~~62. The Great Northern Transmission Line constitutes the United States portion of a joint effort with Manitoba Hydro to construct a new Canada-United States transmission interconnection.

~~61.~~63. Manitoba Hydro will construct and have sole ownership of the Canadian portion of this new interconnection.

~~62.~~64. On the United States side, Minnesota Power will have majority ownership (51 percent) of the Project. The balance of the Project (49 percent) will initially be owned by a subsidiary of Manitoba Hydro, although the subsidiary may sell all or a

[12] *Id.*, pp. 3-4 and MPUC Docket No. E-015/TL-14-21.
[13] *Id.*
[14] Ex. 38, p. 5 (Donahue Direct).
[15] Ex. 42, p. 4 (Winter Direct).
[16] *Id.*

portion of its share to one or more United States utilities, before, during or after construction.[17]

~~63.~~65. In its CON Application, Minnesota Power indicated that it would be responsible for 33.3 percent of the Project's revenue requirements, with the 17.7 percent differential between this responsibility share and the Company's ownership share covered by Manitoba Hydro under a "must take fee" to be included in the 133 MW Renewable Optimization Agreements ("ROAs"), which were then still being finalized.[18]

~~64.~~66. At that time, the Project was assumed to have a total transfer capability of 750 MW.[19] However, Minnesota Power agreed to be responsible for only the 250 MW of transfer capability necessary to take delivery under the 250 MW Agreements, thus the 33.3 percent share of the capital cost responsibility at that time.[20]

~~65.~~67. Operations and maintenance expenses were handled similarly, with Minnesota Power again responsible for a 33.3 percent share of the costs.[21]

~~66.~~68. Since the CON Application was filed, Minnesota Power continued to ensure that its customers would only bear the financial responsibility associated with 250 MW of transfer capability.[22] However, three subsequent events impacted the final allocation of revenue responsibility between Minnesota Power and Manitoba Hydro. First, the total transfer capacity of the line was estimated to be 883 MW, not 750 MW.[23] Second, Minnesota Power and Manitoba Hydro finalized the 133 MW ROAs.[24] Third, the Company and Manitoba~~Minnesota~~ Hydro executed a FCA.

~~67.~~69. In order for Minnesota Power to retain a 51 percent ownership in the line, while not bearing more revenue responsibility than that associated with 250 MW of transfer capability, the final agreements between the Company and Manitoba Hydro call for: (1) Minnesota Power to ultimately bear 28.3 percent responsibility for the capital costs of the Project (250 MW/883 MW), (2) for the "must take fee" included in the 133 MW ROAs to continue covering 17.7 percent of the responsibility for both the capital costs and the operating and maintenance costs, and (3) for Manitoba Hydro to provide a

[17] Ex. 34, p. 13 (McMillan Direct).
[18] Ex. 9, p. 16.
[19] *Id.*
[20] *Id.*
[21] *See*, Ex. 40, p. 5 (Donahue Rebuttal).
[22] Ex. 34, p. 14 (McMillan Direct).
[23] *Id.*; Ex. 42, pp. 3-4 (Winter Direct).
[24] Ex. 24, p. 14 (McMillan Direct); Ex. 43, pp. 3 (Winter Direct).

five percent Contribution In Aid of Construction ("CIAC") payment to the Company – collectively totaling the 51 percent ownership held by Minnesota Power.[25]

~~68.~~70. Regarding operating and maintenance expenses, Minnesota Power could identify no change in operating expenses associated with the incremental increase in capacity.[26] Therefore, the Company agreed to retain its 33.3 percent responsibility for these expenses.[27]

~~69.~~71. While the Manitoba Hydro subsidiary will have an initial 49 percent ownership interest in the Project, Manitoba Hydro has stated it does not intend to maintain a long-term interest in the Project. Thus, the FCA provides for Manitoba Hydro to assign its interest to another MISO Transmission Owner or, if it does not find another owner, to Minnesota Power.[28]

~~70.~~72. In order to ensure that any such assignment cannot negatively impact Minnesota Power and its ratepayers, Minnesota retained full consent rights to any transfer to a third party.[29]

~~71.~~73. Minnesota Power testified that in order for it to consent to a new minority owner, that owner would have to not only assume Manitoba Hydro's financial obligations, but would have to agree to hold the Minnesota Power pricing zone neutral.[30]

~~72.~~74. If Manitoba Hydro chooses to assign its ownership interest to Minnesota Power, the Company will still bear only 33.3 percent of the operations and maintenance costs, with the remainder covered by Manitoba Hydro through the "must take fee" and through a CIAC.[31]

~~73.~~75. Given the various contractual agreements between Minnesota Power and Manitoba Hydro, the financial responsibility for the Project breaks down as follows,

[25] Ex. 24, pp. 14-15 (McMillan Direct); Ex. 40, p. 5 (Donahue Rebuttal). Minnesota Power maintained a 33 percent operating and maintenance expense ("O&M") allocation, since it could identify no additional O&M expenses associated the incremental increase in capacity from 750 MW to 883 MW. Ex. 40, p. 5 (Donahue Rebuttal).
[26] Ex. 40, p. 5 (Donahue Rebuttal).
[27] *Id.*, pp. 5-6.
[28] Ex. 40, pp. 3-5 (Donahue Rebuttal); V. 1, pp. 110-111 (Donahue).
[29] *Id.*
[30] *Id.*
[31] *Id.* pp. 3-7.

depending on whether Manitoba Hydro assigns its interest to Minnesota Power or Manitoba Hydro or an assignee retain 49 percent ownership [32]:

	Final Structure	
Responsibility For:	Under 100% MP ownership	Under 51% MP / 49% Other ownership
Investment:		
MP	46.00%	46.00%
MH (CIAC)	54.00%	5.00%
MH-Assignee	NA	49.00%
Total	100.00%	100.00%
Revenue Req. - Capital Cost:		
MP Ratepayer	28.30%	28.30%
MH (ROA Fee)	17.70%	17.70%
MH (CIAC)	54.00%	5.00%
MH or Assignee	N/A	49.00%
Total	100.00%	100.00%
Revenue Req. - O&M:		
MP Ratepayer	33.30%	33.30%
MH (ROA Fee)	17.70%	17.70%
MH (CIAC)	49.00%	0.00%
MH or Assignee	N/A	49.00%
Total	100.00%	100.00%

C. Timing

~~74.~~76. Project construction is anticipated to begin in 2016, with an in-service date of June 1, 2020 as required under the 250 MW Agreements.[33]

~~75.~~77. In order to maintain this schedule and to achieve the contractually required in-service date, Minnesota Power began its outreach efforts for permitting and routing in mid-2012.[34]

~~76.~~78. The Company continues to make progress on its milestones to achieve this in-service date, including the filing of the Presidential Permit Application, required for an international border crossing.[35]

[32] Ex. 40, p. 8, Table 3 (Donahue Rebuttal).
[33] Ex. 9, pp. 2, 35; Ex. 34, p. 11 (McMillan Direct); Ex. 38, p. 5 (Donahue Direct).
[34] Ex. 9, p. 78.

D. Costs

79. Minnesota Power has provided five estimates for the total cost of the Project since filing its CON Application on October 21, 2013.[36]

~~77.~~80. In its CON Application, the Minnesota Power provided an initial range of estimated costs for the Project of $406.2 million and $609.3 million.[37] At that time, the Company had a number of potential routes still under consideration, so the estimate used a "proxy" route and was based on the information then available to the Company.[38]

~~78.~~81. When the Company filed its Route Permit Application,[39] Route Alternatives and Segment Options were identified. Therefore, the Company re-examined and refined its prior cost range estimate to reflect the route data then available. In addition, Minnesota Power refined its estimate related to expected construction costs, including the use of matting in wetlands to mitigate potential wetland impacts.[40] In conjunction with its Route Permit Application, the Company developed a cost estimate for one of two potential routes of **[TRADE SECRET BEGINS: TRADE SECRET ENDS]** million, according to Exhibit(__MD), Schedule 4 (Trade Secret).[41]

82. Based on preliminary engineering considerations of the Route Alternatives and Segment Options, as of April 15, 2014 Minnesota Power estimated the construction of the Project on the Route Alternatives (including any combination of proposed Segment Options), including substation facilities, to cost between ~~roughly $500~~$495.5 million and ~~$650~~$647.7 million in 2013 dollars.[42]

~~79.~~83. In response to LPI's Information Request No. 24, Minnesota Power further revised its estimate of the total Project cost to **[TRADE SECRET BEGINS: TRADE SECRET ENDS]** million, which is the same amount the Company cited in the FCA.[43]

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[35] *See* Office of Energy OE Docket No. PP-398, 79 Fed. Reg. 27,587 (May 14, 2014); 79 Fed. Reg. 68,673 (Nov. 18, 2014).
[36] Ex. 50, pp. 5-6 (Kollen Direct).
[37] Ex. 9, p. 27; Ex. 38, p. 4 (Donahue Direct).
[38] *Id.*
[39] MPUC Docket No. E-015/TL-14-21.
[40] Ex. 38, pp. 4-5 (Donahue Direct).
[41] Ex. 50, p. 6 (Kollen Direct).
[42] ~~*Id.*;~~Ex. 38, Schedule 4 (Donahue Direct).
[43] Ex. 59.

84. Finally, in July of 2014, a MISO-sponsored facility study report concluded that the 500 kV Series Compensation Station originally budgeted at the expanded Blackberry Substation should now be a separate facility located at the midpoint of the 500 kV transmission line. Incorporating that change and accounting for property taxes that will assessed against Project assets before the in-service date of June 1, 2020, Minnesota Power estimated that the Project will cost between $557.9 million and $710.1 million. That remains the Company's current cost estimate.[44]

85. All of the cost estimates provided by Minnesota Power are stated in 2013 dollars and not in "as-spent" dollars. Thus, none of the cost estimates includes construction cost inflation. For accounting purposes, the Company will incur and record costs in "as-spent" dollars, not in 2013 dollars, and the Company will seek to recover the "as-spent" dollars from customers.[45]

86. If added to the **[TRADE SECRET BEGINS: TRADE SECRET ENDS]** million cost estimate that the Company provided in the FCA, construction cost inflation would increase the estimate to **[TRADE SECRET BEGINS: TRADE SECRET ENDS]** million in "as-spent" dollars, an increase of **[TRADE SECRET BEGINS: TRADE SECRET ENDS]** million.[46]

87. None of the cost estimates provided by Minnesota Power includes financing costs that the Company will incur during construction.[47] The Company will seek to recover the financing costs from customers, either by capitalizing the financing costs as allowance for funds used during construction ("AFUDC") and then recovering those costs, along with all other construction work in progress ("CWIP") costs, over the service life of the assets, or by recovering a current return on CWIP during the construction period.[48]

~~80.~~88. If added to the cost estimate of **[TRADE SECRET BEGINS: TRADE SECRET ENDS]** million in as-spent dollars that the Company provided in response to LPI's Information Request No. 17, financing costs would increase the estimate to **[TRADE SECRET BEGINS: TRADE SECRET ENDS]** million, an increase of **[TRADE SECRET BEGINS: TRADE SECRET ENDS]** million in "as-spent" dollars.[49]

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[44] *Id.*, p. 5; V. 1, p. 113 (Donahue).
[45] Ex. 50, pp. 8-9 (Kollen Direct).
[46] Ex. 50, pp. 9-10 (Kollen Direct).
[47] Ex. 50, p. 9 (Kollen Direct).
[48] Ex. 50, p. 10 (Kollen Direct).
[49] Ex. 50, p. 11 (Kollen Direct).

~~81.~~89. Given the terms of the ROAs and FCA, Minnesota Power ratepayers will be responsible for only 28.3 percent of the Project's total capital costs. Based on the Company's current cost estimate of between $557.9 million and $710.1 million in 2013 dollars, Minnesota Power ratepayers will be responsible for between ~~equating to a range of~~ $158 million ~~to~~ and $201 million,~~.~~[50] excluding construction cost inflation and financing costs.

~~82.~~90. Regarding operating and maintenance costs, primary annual maintenance expense for a transmission line is aerial inspection.[51] These inspections look for broken insulators or other defects which could compromise the line.[52] If issues are identified, ground crews will be dispatched to correct the defect.[53] In addition to structural maintenance, the right-of-way must be kept clear of vegetation.[54] Vegetation control is performed on a scheduled and routine basis and when the aerial inspection discovers issues.[55] The cost for routine maintenance will depend on the topology and the type of maintenance required, but typically runs from $1,100 to $1,600 per mile.[56]

~~83.~~91. Given the terms of the ROAs, Minnesota Power and its ratepayers will be responsible for only 33.3 percent of the operating and maintenance expenses associated with the Project.[57]

IV. MINNESOTA POWER'S AGREEMENTS WITH MANITOBA HYDRO

~~84.~~92. Contracts between Manitoba Hydro and Minnesota Power have particular relevance to this proceeding, since those contracts both provide for the exchange of energy intended to be transmitted over the Project and they establish the relative financial responsibilities of these two entities.

A. The 250 MW Agreements

~~85.~~93. The 250 MW Power Purchase Agreement ("PPA") and 250 MW Energy Exchange Agreement ("EEA") between Minnesota Power and Manitoba Hydro

[50] Ex. 38, p. 5 (Donahue Direct).
[51] *Id.*, p. 6.
[52] *Id.*
[53] *Id.*
[54] *Id.*
[55] *Id.*
[56] *Id.*
[57] Ex. 39, pp. 5-6 (Donahue Rebuttal).

(collectively, "250 MW Agreements") were signed in 2011 and approved by the Commission in 2012.[58]

~~86.~~94. The 250 MW Agreements followed Minnesota Power's 2010 Integrated Resource Plan ("IRP") docket,[59] where the Company identified significant capacity and energy needs in the 2020 to 2035 timeframe, with those needs driven by customer load growth and diversification of the Company's power supply.[60]

~~87.~~95. To address these load and supply changes, the Company included action in its 2010 IRP with the intent to pursue both the 250 MW Agreements with Manitoba Hydro and associated new transmission to deliver that power, with power deliveries beginning in the 2020 timeframe.[61]

~~88.~~96. The inclusion of the 250 MW of Manitoba Hydro hydropower and the new transmission to deliver that power was part of the Company's least cost system-wide long term supply plan and the Commission accepted the Company's 2010 IRP in 2011.[62]

~~89.~~97. The 250 MW Agreements act to optimize Minnesota Power's resources, by allowing Minnesota Power to sell off-peak excess wind energy to Manitoba Hydro and then "buy back" this energy from Manitoba Hydro when needed on the Minnesota Power system.[63]

~~90.~~98. In reviewing and approving the 250 MW Agreements, the DOC-DER and Commission affirmed that Minnesota Power "will need a significant amount of capacity and energy" in the 2020 to 2035 timeframe.[64]

~~91.~~99. The DOC-DER and Commission further affirmed that the 250 MW Agreements "provide the most appropriate resources for [Minnesota Power] to meet its resource needs" over this time period.[65]

~~92.~~100. In the 938 Docket, the DOC-DER and Commission recognized that "both [Manitoba Hydro] and [Minnesota Power] must construct their own new

[58] MPUC Docket No. E-015/M-11-938 ("938 Docket").
[59] MPUC Docket No. E-015/RP-09-1088 ("1088 Docket").
[60] Ex. 43, p. 9 (Rudeck Direct).
[61] *Id.*, pp. 9-10.
[62] *Id.*, p. 10.
[63] *Id.*, pp. 7-8; Ex. 12, Department Comments, p. 20; V. 1, p. 186 (Rudeck).
[64] Ex. 12, Department Comments at p. 4.
[65] Ex. 12, Department Comments at pp. 5, 25.

transmission facilities (in Canada and the USA respectively) to allow Manitoba Hydro to sell the contracted power to MP."[66]

~~93.~~101. Given the importance of these new transmission facilities, 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.[67]

B. The 133 MW Renewable Optimization Agreements

~~94.~~102. On July 30, 2014, Minnesota Power and Manitoba Hydro signed the 133 MW Energy Sale Agreement ("ESA") and 133 MW EEA (collectively, the "Renewable Optimization Agreements" or "ROAs") (together with the 250 MW Agreements, the "Manitoba Hydro Agreements").[68]

~~95.~~103. The 133 MW ROAs bring additional zero emission supply resources to Minnesota Power and further optimize the Company's wind power resources by allowing Minnesota Power to schedule additional energy from the Company's wind-generating facilities to Manitoba Hydro when wind production is high and is not needed for customer load.[69]

~~96.~~104. When Manitoba Hydro uses this Minnesota Power wind power to serve customer load in Manitoba, Manitoba Hydro would be able to temporarily reduce their hydropower generation by decreasing the flow of water through their hydropower plants.[70]

~~97.~~105. The water "stored" during that process would be used later to generate electricity to schedule to Minnesota when wind energy production is low or customer needs are high.[71]

~~98.~~106. This arrangement optimizes the use of both wind-generated energy and hydropower, which brings benefits to customers and allows Minnesota Power to further enhance the carbon-free portion of its long term supply portfolio.[72]

[66] Ex. 12, Department Comments, p. 13.
[67] *Id.*, Ordering Paragraph 2.
[68] Ex. 43, Schedule 2 (Rudeck).
[69] Ex. 43, pp. 15-16 (Rudeck Direct).
[70] *Id.*, p. 16.
[71] *Id.*
[72] *Id.*

~~99.~~107. Through the combined Manitoba Hydro Agreements, Minnesota Power has procured a total of over 1.5 million megawatt hours ("MWh") of hydropower annually, and the ability annually to store 1 million MWh of wind power in Manitoba Hydro's system.[73]

~~100.~~108. The energy taken by Minnesota Power under the ROAs is priced at market and includes the associated environmental attributes.[74] This structure provides optionality for Minnesota Power to either take the energy, if needed for least cost customer supply, or to resell it to the market.[75] In either case, Minnesota Power receives the environmental attributes as part of the transaction.[76]

~~101.~~109. The ROAs also require Manitoba Hydro pay for the transmission delivery costs for the energy associated with the 133 MW ESA through a "must take fee" provision in the EEA. This "must take fee" credits Minnesota Power and its customers for the capital costs associated with 133 MW of the transfer capability of the Project.[77]

~~102.~~110. The ROAs were filed with the Commission for approval and are currently pending Commission action.[78]

C. The Facilities Construction Agreement

~~103.~~111. On September 23, 2014, Minnesota Power, Manitoba Hydro and the Midcontinent Independent System Operator, Inc. ("MISO") executed the Facilities Construction Agreement ("FCA") for the Project,[79] setting forth the ownership percentages and financial responsibilities for the Project, among other terms.

~~104.~~112. The FCA includes provisions requiring Manitoba Hydro to provide a five percent CIAC to Minnesota Power[80] and requires Minnesota Power's full consent if Manitoba Hydro ultimately wishes to assign its interest in the Project to another transmission owner.[81]

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[73] Ex. 34, p. 7 (McMillan Direct).
[74] *Id.*
[75] *Id.*
[76] *Id.*
[77] Ex. 45, pp. 3, 18 (Rudeck Surrebuttal).
[78] MPUC Docket No. E-015/M-14-960 ("960 Docket").
[79] Ex. 40 (MD-R), Schedule 1 (FCA) (Donahue Rebuttal).
[80] *Id.*; Ex. 35, p. 9 (McMillan Rebuttal).
[81] Ex. 40, pp. 3-4 (Donahue Rebuttal).

~~105.~~113. On November 25, 2014, FERC approved the FCA.[82]

~~106.~~114. With that approval, MISO considers the Project an approved project under the MISO tariff and MISO has moved the Project to Appendix A of the MISO Transmission Expansion Plan 14 ("MTEP14").[83]

V. CRITERIA FOR GRANTING A CERTIFICATE OF NEED

~~107.~~115. Minnesota Statutes Section 216B.243 ("CON Statute") governs the granting of a CON for large energy facilities, including high voltage transmission lines such as the Great Northern Transmission Line.

~~108.~~116. The CON Statute requires the Commission to adopt rules setting forth the criteria to be used in its determination of need for such facilities, which the Commission has done for high voltage transmission lines in Minnesota Rules Chapter 7849 ("CON Rules").

~~109.~~117. The CON Statute further identifies certain factors for the Commission to evaluate in its determination of need, specifically:

> (1) the accuracy of the long-range energy demand forecasts on which the necessity for the facility is based;
>
> (2) the effect of existing or possible energy conservation programs under sections 216C.05 to 216C.30 and this section or other federal or state legislation on long-term energy demand;
>
> (3) the relationship of the proposed facility to overall state energy needs, as described in the most recent state energy policy and conservation report prepared under section 216C.18, or, in the case of a high-voltage transmission line, the relationship of the proposed line to regional energy needs, as presented in the transmission plan submitted under section 216B.2425;
>
> (4) promotional activities that may have given rise to the demand for this facility;

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[82] Ex. 64 (FERC Docket No. ER14-2950-000, Order dated November 25, 2014).

[83] https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEP14.aspx

(5) benefits of this facility, including its uses to protect or enhance environmental quality, and to increase reliability of energy supply in Minnesota and the region;

(6) possible alternatives for satisfying the energy demand or transmission needs including but not limited to potential for increased efficiency and upgrading of existing energy generation and transmission facilities, load-management programs, and distributed generation;

(7) the policies, rules, and regulations of other state and federal agencies and local governments;

(8) any feasible combination of energy conservation improvements, required under section 216B.241, that can (i) replace part or all of the energy to be provided by the proposed facility, and (ii) compete with it economically;

(9) with respect to a high-voltage transmission line, 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;

(10) whether the applicant or applicants are in compliance with applicable provisions of sections 216B.1691 and 216B.2425, subdivision 7, and have filed or will file by a date certain an application for certificate of need under this section or for certification as a priority electric transmission project under section 216B.2425 for any transmission facilities or upgrades identified under section 216B.2425, subdivision 7;

(11) whether the applicant has made the demonstrations required under subdivision 3a [regarding use of renewable resources]; and

(12) if the applicant is proposing a nonrenewable generating plant, the applicant's assessment of the risk of environmental costs and regulation on that proposed facility over the expected useful life of the plant, including a proposed means of allocating costs associated with that risk.[84]

[84] Minn. Stat. § 216B.243, subd. 3. The Parties agreed that sections (10) and (12), above, do not apply to the current proceeding. *See* Issues Matrix, December 5, 2014. The remainder of the statutory factors correspond to provisions in the Commission's CON criteria and will be discussed in these Findings under those criteria.

~~110.~~118. The Commission's CON Rules incorporate these statutory factors into four criteria the Commission utilizes in determining if a CON must be granted.[85] Those Rules provide that:

> A certificate of need must be granted to the applicant on determining that:
>
> A. the probable result of denial would be an adverse effect upon 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, considering:
>
> (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 the 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;
>
> B. a more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record, considering:
>
> (1) the appropriateness of the size, the type, and the timing of the proposed facility compared to those of reasonable alternatives;
>
> (2) 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;

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[85] *See In the Matter of the Application of ITC Midwest LLC for a Certificate of Need for the Minnesota – Iowa 345 kV Transmission Line Project in Jackson, Martin, and Faribault Counties;* MPUC Docket No. ET-6675/CN-12-1053, Order Granting Certificate Of Need With Conditions, November 25, 2014, pp. 3-4.

> (3) the effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives; and
>
> (4) the expected reliability of the proposed facility compared to the expected reliability of reasonable alternatives;
>
> C. by a preponderance of the evidence on the record, the proposed facility, or a suitable modification of the facility, will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health, considering:
>
> (1) the relationship of the proposed facility, or a suitable modification thereof, to overall state energy needs;
>
> (2) the effects of the proposed facility, or a suitable modification thereof, upon the natural and socioeconomic environments compared to the effects of not building the facility;
>
> (3) the effects of the proposed facility, or a suitable modification thereof, in inducing future development; and
>
> (4) the socially beneficial uses of the output of the proposed facility, or a suitable modification thereof, including its uses to protect or enhance environmental quality; and
>
> D. the record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.[86]

~~111.~~119. As the Applicant, Minnesota Power bears the burden of demonstrating the need for the Project,[87] with the specific burden being proof by a preponderance of the evidence.[88]

~~112.~~120. With respect to alternatives to the Project, Minnesota Power meets its burden by showing that the Project is a reasonable and prudent way to satisfy the articulated and demonstrated needs. Minnesota Power fails to meet this burden if *another*

[86] Minn. R. 7849.0120.
[87] *See* Minn. Stat. § 216B.243, subd. 3.
[88] *See* Minn. R. 1400.7300, subp. 5 and Minn. R. 7849.0120.

party demonstrates that there is a more reasonable and prudent alternative to the facility proposed by the applicant.[89]

VI. APPLICATION OF CERTIFICATE OF NEED CRITERIA

A. Adequacy, Reliability or Efficiency of Energy Supply

1. Minnesota Power Energy Supply

~~113.~~121. Beginning with the Company's 2010 IRP[90], Minnesota Power's IRPs and Advanced Forecast Reports ("AFRs") have consistently shown the need for additional capacity and energy in the 2020 to 2035 timeframe.[91]

~~114.~~122. In its 2010 IRP Minnesota Power identified significant capacity and energy needs in the 2020 to 2035 timeframe driven by customer load growth and diversification of its power supply.[92]

~~115.~~123. To address these needs, the Company included action in its 2010 IRP with the intent to pursue agreements with Manitoba Hydro and associated new transmission to deliver that power, with power deliveries beginning in the 2020 timeframe.[93] The inclusion of 250 MW of Manitoba Hydro hydropower and new transmission (now provided for by the Project) was part of the Company's least cost system-wide long term supply plan.[94]

~~116.~~124. Following the 2010 IRP, Minnesota Power entered into the 250 MW Agreements with Manitoba Hydro to meet a portion of its future supply needs.

~~117.~~125. In reviewing and approving the 250 MW Agreements, the Department and Commission found, consistent with the 2010 IRP, that Minnesota Power "will need a significant amount of capacity and energy" in the 2020 to 2035 timeframe.[95]

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[89] *In the Matter of the Application of the City of Hutchinson (Hutchinson Utilities Commission) for a Certificate of Need to Construct a Large Natural Gas Pipeline*, Minn. App. A03-99, September 23, 2003, p. 11 (citing *State v. Paige*, 256 N.W.2d 298, 304 (Minn. 1977) (emphasis added).
[90] MPUC Docket No. E-015/RP-10-1088 ("1088 Docket")
[91] Ex. 43, p. 9 (Rudeck Direct).
[92] *Id.*
[93] *Id.*
[94] *Id.*, pp. 9-10.
[95] Ex. 12, Commission Order and Department Comments at p. 4.

~~118.~~126. The Department and Commission determined that the 250 MW Agreements "provide the most appropriate resources for [Minnesota Power] to meet its resource needs" over this time period.[96]

~~119.~~127. Given the need for new transmission to deliver this power, the Commission specifically requested that Minnesota Power update the Commission on the progress on the milestones achieved regarding the completion of these new transmission facilities.[97] The Company filed the CON Application for the Project to gain approval for these news transmission facilities.

~~120.~~128. Minnesota Power's need for the additional capacity and energy to be delivered pursuant to the Manitoba Hydro Agreements continues to be demonstrated in Minnesota Power's 2013 and 2014 AFRs.[98]

~~121.~~129. Due to Minnesota Power's industrial load concentration, the AFRs include multiple industrial load growth scenarios, with the Moderate Growth scenario in both the 2013 and 2014 AFR submittals providing the most relevant information for the purpose of this proceeding.[99]

~~122.~~130. Given the anticipated new load in Minnesota Power's service territory being projected for the 2020 time period, the AFR process continues to support Minnesota Power's need for the additional capacity and energy to be purchased from Manitoba Hydro.[100]

~~123.~~131. The Company's 2013 IRP, approved by the Commission in November of 2013,[101] further supports Minnesota Power's need for the capacity and energy to be purchased from Manitoba Hydro.

~~124.~~132. In that proceeding, the Commission determined that even after approval of the 250 MW Agreements, Minnesota Power needs to add capacity to its system.[102]

~~125.~~133. The 133 MW ROAs provide additional needed resources and will also be delivered to Minnesota Power via the Project.[103]

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[96] Ex. 12, Commission Order and Department Comments at pp. 5, 25.
[97] *Id.*, Ordering Paragraph 2.
[98] Ex. 18 (2013 AFR); Ex. 43 (AJR), Schedule 1 (2014 AFR).
[99] Ex. 43, p. 10-13 (Rudeck Direct).
[100] *Id.*, pp. 10-11.
[101] MPUC Docket No. E-015/RP-13-53.
[102] Ex. 52, p. 11 (Shah Direct).

~~126.~~134. The Project provides the benefits of the economies of scale of a large project and facilitates the delivery of the full 383 MW of power from Manitoba Hydro, while Minnesota Power and its ratepayers only bear the financial responsibility for 250 MW of that capacity, because Manitoba Hydro will bear the bulk of the construction costs and a majority of the long-term operations expenses and risk associated with building and owning a 500 kV asset. Manitoba Hydro is also enabling Minnesota Power to utilize the Manitoba Hydro system for energy storage as well as allowing Minnesota Power to keep the value of environmental attributes associated with energy purchases. Minnesota Power's customers stand to benefit over the next four decades from this opportunity.[104]

~~127.~~135. Minnesota Power's Conservation Improvement Program ("CIP") is integral part of its resource planning.[105] The Company's CIP efforts focus on increased efficiencies that reduce the amount of energy needed for certain uses and include eligible residential, commercial, and small scale renewable programs.[106] Since 2010, Minnesota Power's CIP efforts have resulted in surpassing the 1.5 percent annual savings goal set by State statute, saving 77,630 MWh in 2013 and these conservation levels are built into Minnesota Power's IRPs, AFRs and other resource acquisition proceeding, including the 938 Docket approving the 250 MW Agreements.[107]

~~128.~~136. 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 Minnesota Power's need for additional capacity and energy from Manitoba Hydro, and the Project which enables the delivery of that power.[108]

~~129.~~137. The Department agreed that conservation does not lessen the need for the Project or serve as an alternative to it. [109]

~~130.~~138. Minnesota Power has engaged in no direct promotional activities to encourage the use of more power.[110] Rather, the Project responds to increased need for capacity and energy, in part due to economic growth on the Iron Range.[111]

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[103] Ex. 43, pp. 15-16 (Rudeck Direct).
[104] Ex. 34, pp. 12-13 (McMillan Direct).
[105] Ex. 43, p. 32 (Rudeck Direct).
[106] *Id.*; Ex. 21 (Executive Summary, Minnesota Power 2014-2016 Triennial Conservation Improvement Plan filing).
[107] *See Id.*; Ex. 53, p. 21 (Rakow Direct) (noting conservation was considered in the approval of the 250 MW Agreements).
[108] *Id.*; Ex. 9, p. 107.
[109] Ex. 53, pp. 20-21 ((Rakow Direct).

~~131.~~139. The Project also helps 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.[112] This minimizes Minnesota Power's and its customers' exposure to the risk of future emissions regulations.[113]

~~132.~~140. The Department examined whether Manitoba Hydro has engaged in promotional activities that have given rise to the need for the Project.[114] The Department stated that, while Manitoba Hydro may market "their brand of energy," it has not promoted increased demand overall.[115] Thus, the Department also concluded that promotional practices have not created the need for the Project.

~~133.~~141. The existing interface between Manitoba and the United States, consisting of three 230 kV lines and the Dorsey-Forbes 500 kV line, is unable to accommodate increased transfer of energy from Manitoba into the United States.[116]

~~134.~~142. An unplanned outage of this existing 500 kV tie line is also the second largest contingency in the entire MISO footprint.[117] 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. This will improve system reliability to the benefit of Minnesota Power, its customers and the broader State and regional markets.[118]

~~135.~~143. The existing transmission interface between Manitoba and the United States, consisting of three 230 kV lines and one 500 kV line, is unable to accommodate increased transfer of energy from Manitoba into the United States.[119]

~~136.~~144. Upgrades of existing facilities also cannot meet the need met by the Project. To increase 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 the current 500 kV line is the largest, lowest impedance

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110 Ex. 9, p. 15.
111 *Id.*
112 *Id.*
113 *Id.*; Ex. 43, pp. 13-14 (Rudeck Direct).
114 Ex. 53, p. 13 (Rakow Direct).
115 *Id.*
116 Ex. 9, p. 13; Ex. 42, p. 9 (Winter Direct).
117 Ex. 42, p. 12 (Winter Direct).
118 Ex. 9, p. 13; Ex. 42, pp. 9-13.
119 Ex. 42, p. 9 (Winter Direct); Ex. 53, p. 12 (Rakow Direct).

line on the interface, the majority of incremental transfers from Manitoba to the United States would flow on this line, requiring increased capacity on the line.[120]

~~137.~~145. While it is technically feasible to increase the rating of this line, the 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, resulting from the electrical inefficiencies of increasing utilization of the line.[121] Finally, upgrading existing facilities would certainly not enable increases in hydroelectric power imports from Manitoba to the United States in excess of the Manitoba Hydro Agreements, and potentially would not facilitate the full 383 MW needed to fulfill those Agreements.[122]

~~138.~~146. In the 938 Docket, the Commission recognized that both Manitoba Hydro and Minnesota Power would need to construct new transmission facilities for Minnesota Power to take delivery of the capacity and energy provided by the 250 MW Agreements.[123]

~~139.~~147. Denial of the CON for the Project would not allow Minnesota Power to take delivery of the power called for under the Manitoba Hydro Agreements, leaving Minnesota Power with significant unmet needs beginning in 2020 and adversely impacting the adequacy, reliability and efficiency of energy supply to Minnesota Power and its customers.[124]

2. State and Regional Energy Supply

~~140.~~148. In public comments filed November 20, 2014, MISO stated, in part:

> As the result of MISO's work with the Applicant in the above-captioned case and its independent review of the proposed transmission project, MISO considers the Great Northern Transmission Line Project a result of sound execution of MISO's collaborative Transmission Planning process. This Project was reviewed under both the transmission service request process found in Module B of MISO's Tariff, and as a targeted study under a technical study task force exploring the value added by this transmission Project to the MISO footprint as described in Attachment FF, Transmission Expansion Planning Protocol, of MISO's Tariff. Both studies confirmed

[120] Ex. 42, p. 11 (Winter Direct).
[121] *Id.*, pp. 11-12.
[122] *Id.*, p. 12.
[123] Ex. 12, Ordering Paragraph 2 and Department Comments, p. 13.
[124] Ex. 43, p. 28 (Rudeck Direct).

the appropriateness of the Project to address system needs and opportunities.[125]

~~141.~~149. By increasing transfer capability between Canada and the United States, the Project enables State and regional utilities increased access to Manitoba Hydro hydropower.[126]

~~142.~~150. Manitoba Hydro has a long history of energy trading with multiple State and regional utilities, including Xcel Energy, Great River Energy and Wisconsin Public Service.[127]

~~143.~~151. Manitoba Hydro is currently engaged in a significant development plan that will support increased energy trading with Minnesota Power and other United States utilities.[128] Manitoba Hydro's approved development plan includes construction of the 695 MW Keeyask Generating Station – construction which began in July 2014.[129] This development plan also includes the Manitoba transmission facilities that will meet the Project at the United States – Canada border, providing the transmission capacity for new export sales.[130]

~~144.~~152. The Project, together with this Canadian portion of the new interconnection being constructed by Manitoba Hydro, will have enough capacity to deliver the 383 MW contracted for in the Manitoba Hydro Agreements, as well as 500 MW of additional hydropower to other utilities in Minnesota and the region, thereby meeting future State and regional energy needs.[131]

~~145.~~153. While large hydropower transfers like this do not satisfy the current renewable energy mandates in Minnesota, such a new hydropower transfer could also support compliance with renewable energy requirements for utilities in Wisconsin and other states.[132]

~~146.~~154. The Project will also facilitate significant addition of new wind generation and reduce the curtailment of those wind resources. As demonstrated by the

[125] MISO Comment Letter, November 20, 2014, p. 1 (eDocket Document ID 201411-104808-01), Public Comment Exhibit C.
[126] Ex. 43, pp. 28-29 (Rudeck Direct).
[127] *See* Ex. 34, pp. 8-9, 21 (McMillan Direct).
[128] *Id.*, pp. 10-12.
[129] *Id.*
[130] *Id.*
[131] *Id.*
[132] *See, e.g.*, Wis. Stat. § 196.378, as amended by 2011 Wis. Act 34.

MISO Manitoba Hydro Wind Synergy Study, a new 500 kV interconnection with Manitoba will provide "significant benefits" to the entire MISO footprint, including substantial reductions in wind curtailments and better utilization of both wind and hydro resources,[133] meaning increased efficiency of the energy supply system as a whole. These benefits over 20 years were valued at approximately $1.6 billion in 2012 dollars for the northern MISO region.[134]

~~147.~~155. Because Manitoba Hydro's customer needs peak in the winter and many Minnesota and other regional utilities face their peak needs in the summer, Manitoba Hydro and United States utilities have engaged in "seasonal diversity exchanges."[135] In these exchanges Manitoba Hydro supplies surplus power from its system in the summer and United States utilities supply surplus power in the winter, lessening the need for utilities on either side of the border to build additional peaking resources.[136]

~~148.~~156. By facilitating more energy trading, the Project can bring more load balancing benefits, increasing the efficiency of the overall supply system while also reducing State and regional utilities' need to depend on price volatile and carbon-emitting natural gas resources.[137]

~~149.~~157. The record demonstrates that appropriate long-term capacity for the interface between Manitoba and the United States can only be achieved efficiently, economically, and reliably with a single new transmission line build large enough to facilitate the Manitoba Hydro Agreements and additional energy exchanges to meet the energy needs of Minnesota Power, the State and the region.[138]

~~150.~~158. The Project will provide the needed incremental export capability for hydroelectric resources generated in Manitoba, without inherently limiting potential transmission outlet capability for other resources.[139] The Project alleviates the main thermal constraint associated with the North Dakota – Manitoba "loop flow" phenomenon, and thereby facilitates less interaction between power generated in North Dakota and power generated in Manitoba.[140] As a result, the Project enables the wind-

[133] Ex. 41, pp. 7-8 (Hoberg Direct); Ex. 19 (MISO Hydro Wind Synergy Study).
[134] *Id.*
[135] Ex. 34, p. 9 (McMillan Direct).
[136] *Id.*
[137] *Id.*
[138] *Id.*
[139] Ex. 42, p. 8 (Winter Direct); Ex. 62 (Loop Flow Impact Study).
[140] *Id.*

hydropower synergy described in the MISO Wind Synergy Study,[141] without creating other adverse consequences.[142]

~~151.~~159. No other significant transmission project addressing the United States – Manitoba interconnection currently exists which can provide the State and regional benefits provided by the Project.[143]

~~152.~~160. Denial of the CON for the Project would not allow State or regional utilities increased access to Manitoba Hydro hydropower and would not address the regional reliability concerns with the current United States – Canada interface, adversely impacting the adequacy, reliability and efficiency of energy supply to the State and the region.

B. Alternatives

1. Generation Alternatives

~~153.~~161. As set forth in Minnesota Power's Certificate of Need Application, the~~The~~ Project is required for Minnesota Power to take delivery of the power provided for under the 250 MW ~~Manitoba Hydro~~ Agreements.[144]

~~154.~~162. The Company entered into the ~~Manitoba Hydro~~250 MW Agreements only after conducting analyses that also considered market purchases; advanced coal-fired generation, combustion gas turbines and combined cycle gas turbines; other renewable generation; and incorporating demand side management and conservation across a wide range of future energy industry assumptions and sensitivities.

163. As discussed in the 938 Docket, using its Strategist model for screening of reasonable alternatives, the Company concluded that a natural gas-fired combined cycle unit may be the only reasonable alternative to the hydropower provided under the 250 MW Agreements.[145] ~~That analysis did not incorporate the financial benefits to Minnesota Power and its ratepayers of the 133 MW ROAs and the FCA, since Minnesota Power and Manitoba Hydro had not yet entered into those transactions.~~

~~155.~~164. LPI witness Mr. Kollen presented undisputed evidence that, over 40 years, the estimated cost of a natural gas-fired combined cycle alternative would be

[141] Ex. 19 (MISO Wind Synergy Study).
[142] Ex. 42, p. 8 (Winter Direct); Ex. 62 (Loop Flow Impact Study).
[143] Ex. 43, pp. 28-29 (Rudeck Direct).
[144] Ex. 9, p. 4 (Application);
[145] Ex. 43, pp. 29-30 (Rudeck Direct).

approximately $52.90/MWh and the estimated cost of the 250 MW Agreements would be approximately $51.30/MWh, in 2011 dollars.[146]

~~156.~~165. In comparison to a natural gas plant, the ~~Manitoba Hydro~~250 MW Agreements ~~provide more price certainty and~~potentially mitigate carbon risks in Minnesota Power's future power supply~~, compared to a gas-fired facility~~. Additionally, when combined with Minnesota Power's wind supply portfolio, the ~~Manitoba Hydro~~250 MW Agreements bring a flexible energy supply with base load characteristics.[147]

~~157.~~166. In reviewing the 250 MW Agreements, the Department and Commission found in the 938 Docket that those a~~A~~greements "provide the most appropriate resources for [Minnesota Power] to meet its resource needs" over the 2020 to 2035 time period.[148] But Minnesota Power did not update the Strategist modeling in the 938 Docket nor did Minnesota Power provide any evidence to refute the near cost parity of a natural gas-fired combined cycle alternative in this docket.

~~158.~~167. Minnesota Power also examined the potential for distributed generation or community based energy development ("C-BED") projects to meet the needs met by the Project. While the Company is exploring distributed generation and C-BED opportunities, any such resources the Company or its customers may develop cannot displace the need for the Project and the 383 MW of hydropower it enables Minnesota Power to receive.[149]

~~159.~~168. The Department also considered generation alternatives and agreed that "new generation, distributed generation, and C-BED alternatives all fail to pass a screening test in that there is no reason to conclude that such alternatives could meet the claimed need to deliver the energy and capacity called for under the [agreements with Manitoba Hydro]. Therefore, the generation alternatives do not need to be considered further" in this proceeding.[150]

[146] Ex. 50, p. 8 (Kollen Direct).
[147] Ex. 43, pp. 29-30 (Rudeck Direct).~~*Id.*~~
[148] Ex. 12, Commission Order and Department Comments at pp. 5, 25.
[149] Ex. 43, p. 31 (Rudeck Direct); Ex. 9, pp. 72-73.
[150] Ex. 53, p. 20 (Rakow Direct).

2. Transmission Alternatives

a. Alternative Voltages

~~160.~~169. Compared to the 500 kV Project, a 230 kV transmission line would impose higher costs on Minnesota Power and its ratepayers than the Project.[151]

~~161.~~170. For the Project, Minnesota Power ratepayers will be responsible for only 28.3 percent of the capital costs, estimated to equate to $158 million to $201 million.[152]

~~162.~~171. The 230 kV alternative is estimated to cost between $277 million and $355 million.[153] Moreover, Minnesota Power and its customers would bear 100 percent responsibility for those costs and 100 percent responsibility for the operations and maintenance costs, meaning the 230 kV alternative would be substantially more expensive for Minnesota Power and its customers than the Project.[154]

~~163.~~172. The Department analyzed the 230 kV alternative and concluded that the Project "would have far lower revenue requirements than a standalone 230 kV transmission line."[155]

~~164.~~173. A 230 kV alternative does not adequately meet Minnesota Power's needs and cannot meet the long-term needs of the region and would not be environmentally preferable over the long-term.[156]

~~165.~~174. A 230 kV line from the Riel Substation in southern Manitoba to Minnesota Power's Shannon Substation on the Iron Range could facilitate 250 MW of incremental Manitoba to United States transfer capability with no thermal constraints.[157] However, it is unclear whether or not the same project could facilitate the total incremental transfer capability required by the 383 MW to be delivered under the

[151] Ex. 9, pp. 28-29; Ex. 34, p. 19 (McMillan Direct).
[152] *Id.*
[153] Ex. 38, pp. 12-13 (Donahue Direct).
[154] *Id.*; Ex. 34, p. 19 (McMillan Direct); V. 1, p. 26 (McMillan).
[155] Ex. 53, p. 38 (Rakow Direct).
[156] Ex. 42, p. 11 (Winter Direct).
[157] Ex. 42, p. 14 (Winter Direct), Ex. 30 (MISO MH-US TSR Sensitivity Analysis Draft Report (Eastern Plan), July 13, 2013.

Manitoba Hydro Agreements.[158] It is also unclear whether or not stability constraints would exist at either the 250 MW or 383 MW incremental transfer level.[159]

~~166.~~175. Given the favorable characteristics of hydropower resources and the risks associated with carbon-emitting fuel sources, Manitoba Hydro has had several customers and potential customers request transmission service for delivery of energy and capacity of its hydropower in the recent past.[160] Developing a transmission solution now that can deliver 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.[161]

~~167.~~176. In contrast, constructing a new 230 kV transmission line now would not provide an optimal long-term solution for an interface poised to see significant growth over the next 15 to 20 years and would simply require further construction in the future – adding significant financial and environmental costs and impacts.[162]

~~168.~~177. The Department analyzed the 230 kV alternative and concluded that "a 500 kV transmission line would have a lower internal cost and lower line losses, and thus societal cost, than the 230 kV alternative and is the preferred voltage."[163]

~~169.~~178. A 345 kV alternative fails to provide a reasonable alternative since it would not be capable of the same capacity as a single 500 kV line.[164] An equivalent project to a single 500 kV line would be a double circuit 345 kV line, which would be similar in construction cost or more expensive than the Project.[165] Moreover, there is no existing 345 kV equipment in the Winnipeg area where the line originates, meaning that expensive new substation equipment would be required at the Canadian endpoint that is not required for the Project.[166]

~~170.~~179. A 765 kV alternative also fails to provide a reasonable alternative. There is currently no 765 kV transmission in MISO north of Illinois, expensive transformation would be required at each substation to interconnect with existing

[158] *Id.*
[159] *Id.*
[160] Ex. 42, p. 13 (Winter Direct).
[161] *Id.*
[162] *Id.*, pp. 13-14.
[163] V. 2, pp. 80-81 (Rakow).
[164] Ex. 42, pp. 14-15 (Winter Direct).
[165] *Id.*
[166] *Id.*

transmission facilities systems in Manitoba and Minnesota.[167] Combined with the increased construction costs of a higher voltage line, the overall cost increase and operational complexity would not more reasonably and prudently meet the needs identified in this docket, compared to a 500 kV build.[168]

b. Alternative Endpoints

~~171.~~180. In its CON Application, Minnesota Power provided a detailed discussion of the Fargo Area Study Concept ("Concept") – a hypothetical line traveling a more westerly route than the Project.[169] That discussion demonstrated that the Concept, if built, would result in regional transmission system inefficiencies that would constrain generation outlet capability for North Dakota, Manitoba, or both, requiring potentially large-scale transmission system upgrades that would not be required for the Project.[170]

~~172.~~181. It is highly improbable that the Concept could be turned into a reality in time to meet Minnesota Power's contractual obligation in the Manitoba Hydro Agreements of an in-service date of June 1, 2020, since no entity has yet indicated a willingness to develop and fund such a line.[171]

~~173.~~182. Given the utility service territories traversed by such a line, the Department stated that: "the [Concept] would likely result in a significant misallocation of costs, might transfer responsibility for revenue requirements from [Manitoba Hydro] to ratepayers in Minnesota, and would result in the entire ownership structure of the [project] not being known for quite some time. The misallocation of costs is a significant economic issue."[172]

~~174.~~183. Minnesota Power also considered terminating the Project's 500 kV Line at either the Shannon or Forbes substations.[173] Engineering and siting review found that the Shannon Substation is an inferior long-term solution compared to the Blackberry Substation[174]

~~175.~~184. Minnesota Power also considered the Forbes Substation endpoint. The Forbes Substation also has limited outlet capacity and inferior electrical performance

[167] *Id.*, p. 15.
[168] *Id.*
[169] Ex. 9, pp. 77-104.
[170] Ex. 42, pp. 15-16 (Winter Direct).
[171] *Id.*, p. 16.
[172] Ex. 53, p. 49 (Rakow Direct).
[173] Ex. 9, pp. 104-105; Ex. 42, p. 16 (Winter Direct).
[174] *Id.*

when compared to the Blackberry Substation.[175] Additionally, the Forbes Substation is located south of the Iron Range formation, among active mines. Therefore, the most feasible locations for crossing the Iron Range formation appear to be further west, near Grand Rapids, meaning a Forbes endpoint would increase the overall length of the line, thereby increasing the overall human and environmental impact and cost of the Project.[176]

c. Other Transmission-Related Alternatives

~~176.~~185. 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.[177]

~~177.~~186. 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.[178]

~~178.~~187. Additionally, double circuiting often requires an extended outage of the existing line to construct the new double circuit line in its place. Since an extended outage of any of the four existing Manitoba tie lines would not be acceptable from an overall system reliability and adequacy perspective, 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. Either of these options would add substantial cost to the Project and effectively defeat the main environmental purpose for double circuiting the line.[179] For these reasons, double circuiting is not a reasonable and prudent alternative to the Project.

~~179.~~188. The Company also considered a DC line, since DC lines typically have lower line losses than an AC line of the same length.[180] DC lines 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

175 *Id.*
176 Ex. 42, pp. 16-17 (Winter Direct).
177 *Id.*, p. 17.
178 *Id.*
179 *Id.*, pp. 17-18.
180 *Id.*, p. 18.

customers.[181] Given these costs of DC transmission, the break-even line length at which DC 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, a DC alternative would not be economically justified.[182] Rather, it would add to the total cost of the Project.

~~180.~~189. A new DC line into Manitoba could create serious technical issues for Manitoba Hydro.[183] Therefore, a DC line does not provide a more reasonable and prudent alternative than the Project.

~~181.~~190. Underground high voltage transmission lines impose significantly higher engineering and construction costs than overhead lines. In addition, underground lines suffer higher line losses and additional maintenance expenses throughout their useful life and present serious operating and maintenance challenges due to the relative inaccessibility of the underground conductors.[184] Given these drawbacks, undergrounding does not provide a preferable alternative to the Project.

C. Environmental and Socioeconomic Impacts

~~182.~~191. The Project enables Minnesota Power to meet a growing customer need by taking delivery under the Manitoba Hydro Agreements. The Commission has already determined that the 250 MW Agreements provide the most appropriate resource to meet that portion of the Company's needs. In making that determination, the Commission considered a number of factors, including the price of the power. Affordable and reliable power is critical to Minnesota Power and its customers, and can help fuel economic activity in Minnesota Power's service territory.

~~183.~~192. By adding the hydropower made possible by the Project to its supply portfolio, Minnesota Power is also diversifying the Company's resource mix and reducing the overall emissions that would otherwise be associated with its electric supply portfolio.

~~184.~~193. By doing so, the Project reduces overall emissions compared to alternatives and reduces the Company's and its ratepayers' exposure to the cost of potential future emission reduction requirements.

~~185.~~194. The Project optimizes the value of Minnesota Power's wind resources. As demonstrated in the Manitoba Wind Synergy Study, a new 500 kV

[181] *Id.*
[182] *Id.*
[183] *Id.*, p. 19 and Schedule 3.
[184] *Id.*, p. 19.

transmission interconnection between Manitoba and the Iron Range brings significant benefits in the form of reduced wind curtailment and better utilization of both wind and hydro resources, enhancing affordability and further enabling further non-emitting energy to reach the market.[185]

~~186.~~195. The Project provides substantial 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. Property taxes alone are estimated to provide $40,000 to $60,000 per mile in annual revenues to local governments.[186] In total, the Labovitz School of Business and Economics estimated that the Project will generate over $850 million in economic impact in northern Minnesota for the design and construction period of 2016 through 2020.[187]

~~187.~~196. The Project is subject to a thorough and coordinated environmental review. For the current proceeding, that review is reflected in the Environmental Report ("ER").[188] The ER examined potential issues related to air quality, biological resources, cultural, archaeological and historic resources, soil, health and safety and land use, among others. Nothing in the ER provides a basis to conclude that the Project will not be compatible with the human and natural environment.[189]

D. Compliance with Federal, State and Local Regulations

~~188.~~197. The record demonstrates the Company's early and frequent outreach to federal, State, and local officials and its support of a coordinated State and federal environmental review for the Route Permit and Presidential Permit for the Project.

~~189.~~198. Minnesota Power indicated its commitment to continue to work with all federal, State and local governmental authorities to obtain all necessary permits and is fully committed to compliance with those permits."[190]

VII. CONDITIONS

199. In its order accepting Minnesota Power's Application and referring the matter to the OAH, the Commission stated:

[185] Ex. 41, pp. 7-8 (Hoberg Direct); Ex. 19 (MISO Hydro Wind Synergy Study).
[186] Ex. 44, pp. 25-26 (Rudeck Direct).
[187] Ex. 44, p. 25; Ex. 22 (Labovitz School of Business and Economics economic impact study).
[188] Ex. 6 (Environmental Report)
[189] *See Id.*; Ex. 37, pp. 11-12 (Atkinson Direct).
[190] Ex. 34, p. 26 (McMillan Direct)

> The ultimate issue in this case is whether the Applicant's proposed transmission line project meets the need criteria set forth in Minn. Stat. § 216B.243 and Minn. Rules Chapter 7849. This issue turns on numerous factors that are best developed in formal evidentiary proceedings. The parties to this proceeding should address whether the proposed project meets these criteria and address these factors. *The parties may also raise and address other issues relevant to the application.*[191]

200. Consistent with the Referral Order, LPI raised a number of issues relevant to the Application, which are addressed in the findings and recommendations below.

A. Approval of the 133 MW Renewable Optimization Agreements

~~190.~~201. LPI witness Mr. Kollen recommended that Commission approval of the CON be "contingent" upon Commission approval of the 133 MW ROAs between Minnesota Power and Manitoba Hydro and FERC approval of the FCA.[192] No party objected to this recommendation.

~~191.~~202. On November 26, 2014, subsequent to the conclusion of the contested case hearings, FERC approved the FCA.[193] Thus, a "condition" is no longer necessary for the FERC approval.

~~192.~~203. On November 6, 2014, Minnesota Power filed its Petition with the Commission seeking approval of the 133 MW ROAs.[194]

~~193.~~204. The record demonstrates that these agreements provide substantial benefits to Minnesota Power and its ratepayers, including the "must take fee" that credits Minnesota Power customers for the transmission revenue requirements components associated with 133 MW of the Project.[195]

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[191] *In the Matter of the Request of Minnesota Power for a Certificate of Need for the Great Northern Transmission Line Project*, Docket No. E-015/CN-12-1163, ORDER ACCEPTING FILING, VARYING TIME LINES, AND NOTICE AND ORDER FOR HEARING at 4 (Jan. 8, 2014) (the "Referral Order") (emphasis added)..
[192] Ex. 50, p. 3 (Kollen Direct).
[193] Ex. 64 (FERC Approval of FCA).
[194] MPUC Docket No. E-015/M-14-960 (Petition for Approval included in the record as Ex. 55 (ASR-S), Schedule 1 (Rudeck Surrebuttal).
[195] Ex. 35, p. 9 (McMillan Rebuttal); Ex. 45, pp. 2-3 (Rudeck Surrebuttal).

~~194.~~205. In combination with the FCA and other contractual provisions between Minnesota Power and Manitoba Hydro, this feature of the ROAs bring Minnesota Power's and its ratepayers' responsibility for the revenue requirements associated with the Project down to less than 30 percent of the Project cost, as discussed above.

~~195.~~206. In addition, the ROAs include the "wind storage" provisions, discussed above, that further increase the flexibility and value of the Manitoba Hydro resources as part of Minnesota Power's supply.[196]

~~196.~~207. Given the importance of the ROAs to the overall benefits of the Project for Minnesota Power and its customers, LPI, the Department and Minnesota Power all agree that it is reasonable to condition the granting of the CON on the Commission approval of the ROAs.[197]

B. "Capping" Minnesota Power's Cost Recovery

208. In analyzing a CON application, Minn. R. 7849.0120(B)(2) obligates the Commission to 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."

209. In this proceeding, the Company has provided five different estimates for the total cost of the Project, ranging from $406.2 million to $710.1 million, in 2013 dollars.[198] The cost estimate cited in the Company's FERC-approved FCA includes $92 million in contingencies, adding approximately 16% to the cost estimate without the contingencies.[199]

210. In Direct Testimony, LPI witness Mr. Kollen presented evidence that, over 40 years, the estimated cost of a natural gas-fired combined cycle alternative would be approximately $52.90/MWh and the estimated cost of the 250 MW Agreements would be approximately $51.30/MWh, in 2011 dollars.[200] That evidence was not disputed by any party.

211. The Commission has never reviewed an application for a certificate of need where the cost of the proposed transmission project and the cost of energy to be supplied

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[196] Ex. 45, p. 2 (Rudeck Surrebuttal).
[197] Ex. 51, pp. 6-7 (Kollen Surrebuttal); Ex. 55, pp. 1-2 (Rakow Rebuttal); Ex. 35, pp. 9-10 (McMillan Rebuttal).
[198] Ex. 50, p. 6 (Kollen Direct).
[199] *Id.*, pp. 12-13.
[200] *Id.*, p. 8.

by it was as close to the cost of the reasonable alternative and the energy that would be supplied by that reasonable alternative.

~~197. The Commission has historically addressed issues such as cost recovery for projects in the rider or rate case proceeding in which the utility first requests recovery from ratepayers, not in CON proceedings.~~[201]

~~198. Whether or not the Commission addresses cost recovery in this proceeding, it will continue to have the ability to assess the prudence of the costs incurred in developing the Project.~~[202]

~~199.~~212. Based on Mr. Kollen's analysis, LPI recommended that the Commission impose a cost cap that would limit Minnesota Power's recoverable Project costs to **[TRADE SECRET BEGINS: TRADE SECRET ENDS]** million in 2013 dollars, the Company's cost estimate cited in the FCA, including contingencies, in order to ensure that Minnesota Power's customers obtain the claimed value of the Project, the 250 MW Agreements, the 133 MW ROAs, and the FCA.[203] LPI's recommendation is referred to in this proceeding as a "hard cap."

~~200.~~213. In Rebuttal Testimony, the~~The~~ Department recommended a modified version of LPI's recommendation. The Department suggested that it ~~may~~ would be reasonable to clarify ~~for Minnesota Power~~ the terms of ~~its~~ Minnesota Power's future cost recovery. Specifically, the Department suggested that the Commission ~~could~~ should specify that: (1) Minnesota Power would be limited to recover in riders only the amount of costs proposed in this proceeding; (2) the Company could request recovery of costs above this amount only in a rate case~~, where those costs will be subject to full prudence review~~; and (3) Minnesota Power would have the burden of demonstrating the prudency of those additional costs and showing why it would be reasonable to recover them from ratepayers.[204] The Department's recommendation is referred to in this proceeding as a "soft cap."

214. In Surrebuttal Testimony, Minnesota Power agreed ~~to the Department's recommendation of putting in place such a "soft cap" on cost recovery~~with the Department's recommendation for a "soft cap" on recoverable Project costs.[205] ~~This approach is consistent with the Commission's decision on cost recovery regarding~~

~~[201] Ex. 55, pp. 2-3 (Rakow Rebuttal); Ex. 35, pp. 10-11 (McMillan Rebuttal).~~
~~[202] *Id.*~~
[203] Ex. 50, pp. 11-12 (Kollen Direct); Ex. 51, p. 10 (Kollen Surrebuttal).
[204] Ex. 55, pp. 2-3 (Rakow Rebuttal); *see also* Ex. 56, pp. 10-11 (Rakow Surrebuttal).
[205] Ex. 36, p. 3 (McMillan Surrebuttal).

~~Minnesota Power's plan to retrofit its Boswell Unit 4 facility as part of its mercury reduction efforts.~~[206]

~~201.~~215. The Commission has historically addressed issues such as cost recovery for projects in the rider or rate case proceeding in which the utility first requests recovery from ratepayers, not in CON proceedings.[207] However, ~~T~~the Commission ~~very~~ recently used ~~this~~ the ~~same~~ "soft cap" approach in a transmission CON proceeding involving ITC.[208] In its November 25, 2014 Order approving the CON, the Commission stated ~~as follows~~that:

> The Commission recognizes that the ALJ's Findings with respect to the cost of the proposed Project contain little certainty, noting that the final cost of the Project is dependent on a number of factors that are outside of ITC Midwest's control, including the final route (which impacts final design); the timing of construction; the availability of construction crews; and the cost of materials.
>
> Nonetheless, the Commission agrees with the DOC DER's recommendation to condition its approval of the certificate of need by imposing the cost recovery limitation set forth below. The Commission concurs with the Department that it should continue its practice of limiting utilities seeking to recover transmission costs through transmission cost recovery riders to the costs put forward by applicants in certificate of need proceedings -- here, $284,000,000. The Commission continues to believe the fiscal discipline these limits impose benefits ratepayers and that the limits help protect the integrity of the certificate of need process.
>
> At the same time, the Commission recognizes that routing realities cannot always be foreseen with certainty, cost overruns can be prudently incurred, and that recovery over the $284,000,000 level could be justified under some circumstances. The Commission will therefore permit utilities to seek higher recovery levels in future proceedings, with proper documentation and explanation in their rider filings.[209]

216. The Commission has expressed support for cost caps in two recent transmission cost recovery rider proceedings as well, stating separately that "[h]olding the Company to its initial estimate is an important tool to enforce fiscal discipline," and

~~[206] Ex. 35, pp. 10-11 (McMillan Rebuttal).~~
[207] Ex. 55, pp. 2-3 (Rakow Rebuttal); Ex. 35, pp. 10-11 (McMillan Rebuttal).
[208] MPUC Docket No. ET-6675/CN-12-1053.
[209] *Id.*, Order Granting Certificate of Need, p. 6 (emphasis added).

the "imposition of a cap protects the integrity of the certificate of need process, in which it is critical that the cost estimates for the alternatives being compared are as reliable as possible. . . . [C]apping costs at the certificate of need levels is consistent with the Commission's actions in similar cases involving other utilities' riders.[210]

217. Because Minnesota Power's stated need for the Project is to deliver energy and capacity under the 250 MW Agreements and the estimated cost of the Project and the energy to be supplied by it under the 250 MW Agreements is so close to the estimated cost of the reasonable alternative, a "hard cap" on the Company's recoverable Project costs as set forth in the direct testimony of LPI witness Mr. Kollen is reasonable, prudent, and in the public interest.

218. Whether or not the Commission addresses cost recovery in this proceeding, it will continue to have the ability to assess the prudence of the costs incurred in developing the Project.[211]

~~202. LPI witness Kollen disagreed with this approach and instead recommended a "hard cap" that would absolutely prohibit the recovery of costs above the level shown in the record to date.[212] Mr. Kollen recommended that the Commission limit in this Docket any cost recovery to the cost estimate cited in the FERC approved FCA.[213] Mr. Kollen stated that a "hard cap" was necessary to protect ratepayers and because, on cost grounds, the Project was a "close call" when compared to a natural gas fired alternative.~~

~~203. In this proceeding, as with typical CON proceedings, the Company has provided a range of capital costs.[214] This range is appropriate given that a final route and any route permit conditions for this Project will be decided in a separate docket.[215] The Company's cost estimates also appropriately include standard contingencies, which may prove necessary and reasonable.[216]~~

[210] Ex. 51, pp. 12-13 (Kollen Surrebuttal), citing Docket No. E-002/M-12-50, ORDER APPROVING 2012 TCR PROJECT ELIGIBILITY AND RIDER, CAPPING COSTS, AND MODIFYING 2011 TRACKER REPORT, at 4-5 (Feb. 7, 2014) and Docket No. E-017/M-13-103, ORDER CAPPING COSTS, DENYING RIDER RECOVERY OF EXCESS COSTS, AND REQUIRING INCLUSION OF ALL MISO SCHEDULE 26 COSTS AND REVENUES IN TCR RIDER, at 3-5 (Mar. 10, 2014), respectively.
[211] Ex. 55, pp. 2-3 (Rakow Rebuttal); Ex. 35, pp. 10-11 (McMillan Rebuttal).
~~[212] Ex. 50, pp. 5-13 (Kollen Direct).~~
~~[213] Ex. 50, p. 11 (Kollen Direct)~~
~~[214] Ex. 35, p. 10 (McMillan Rebuttal).~~
~~[215] *Id.*~~
~~[216] *Id.*, p. 11.~~

~~204. Under Minnesota law, utilities may recover the reasonable and prudent costs incurred in providing utility service. Minnesota's general ratemaking statute provides that in setting rates, the Commission:~~

> ~~shall give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, and to earn a fair and reasonable return upon the investment in such property. In determining the rate base upon which the utility is to be allowed to earn a fair rate of return, the commission shall give due consideration to evidence of the cost of the property when first devoted to public use, to prudent acquisition cost to the public utility less appropriate depreciation on each, to construction work in progress, to offsets in the nature of capital provided by sources other than the investors, and to other expenses of a capital nature.~~[217]

~~205. Mr. Kollen's recommendation of a "hard cap" is flawed by a false comparison. Mr. Kollen claims that such an absolute limit on cost recovery is necessary because the economics of the Project is a "close call" with the option of building a natural gas facility.~~[218] ~~His analysis compared only the 250 MW Agreements and the Project with a natural gas-fired alternative.~~[219] ~~This analysis does not include the substantial economic and environmental benefits Minnesota Power ratepayers will receive from the 133 MW ROAs.~~

~~206.~~219. ~~A "hard cap" can send inappropriate signals to utilities and encourage resource decisions that are not in the best interest of ratepayers. If the Commission imposes a "hard cap" on a utility in one proceeding, it creates an incentive for the utility to minimize its risks and seek to recover costs through a different proceeding.~~[220] ~~Imposing a "hard cap" on capital costs in a CON proceeding would encourage a utility to abandon capital intensive projects and instead pursue resource options that can receive cost recovery through the fuel clause.~~[221] ~~Doing so would result in a more expensive overall system for ratepayers and an inefficient use of resources.~~[222]

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[217] ~~Minn. Stat. § 216B.16, subd. 6.~~
[218] ~~Ex. 50, pp. 7-8 (Kollen Direct).~~
[219] ~~*Id.*~~
[220] ~~V. 2, pp. 92-94 (Rakow).~~
[221] ~~*Id.*~~
[222] ~~*Id.*~~

C. Other Cost Recovery and Cost Allocation Recommendations

~~207.~~220. LPI ~~witness Kollen~~ made three additional recommendations regarding cost recovery or cost allocation issues that are relevant to the Application. ~~None of these recommendations finds any precedent in past Commission decisions. Both Minnesota Power and the Department testified that these issues will be appropriately addressed in future proceedings, after notice to all potentially interested parties.~~

~~208.~~221. The Commission has the discretion to accept, and should accept, LPI's cost recovery and cost allocation recommendations as reasonable ratepayer protections, as further described below. ~~need not address these issues in the current docket but if it does so, Mr. Kollen's recommendations should be denied.~~

1. ~~Mandating~~ Accrual of AFUDC ~~Treatment~~

222. Accruing AFUDC and recovering those costs through base rates is the default method for recovering construction carrying costs under Minnesota law. However, Minn. Stat. § 216B.16, Subd. 7b(b)(5) gives the Commission the discretion to "approve, reject, or modify" any request for current recovery of CWIP. By granting the Commission discretion rather than directing the Commission to act, the legislature understood that current recovery of CWIP would not be appropriate in all cases. In this proceeding, current recovery of CWIP is sometimes referred to as the "pay now" method of construction cost recovery while the accrual of AFUDC is sometimes referred to as the "pay later" method.

~~209.~~223. ~~Mr. Kollen~~In direct testimony, LPI witness Mr. Kollen recommended that the Commission direct Minnesota Power to accrue AFUDC and recover those costs through base rates ~~recommending that the Commission mandate that the Company accumulate an allowance for funds used during construction ("AFUDC") and require the Company to recover those funds only~~ after the Project is placed into service.[223] In support of his recommendation, Mr. Kollen presented seven reasons why ratepayers should be allowed to defer payment to Minnesota Power through the accrual of AFUDC.[224] No party disputed those reasons.

224. Mr. Kollen emphasized in his surrebuttal testimony that Minnesota Power has not proposed current recovery of CWIP from Manitoba Hydro for its ownership percentage of the Project.[225] Thus, Minnesota Power has proposed that it should be allowed current recovery of CWIP for its ownership percentage of the Project (requiring

[223] Ex. 50, pp. 19-23 (Kollen Direct).
[224] Ex. 50, pp. 21-22 (Kollen Direct).
[225] Ex. 51, pp. 16-17 (Kollen Surrebuttal).

ratepayers to "pay now") but accrue AFUDC for Manitoba Hydro's ownership percentage of the Project (permitting Manitoba Hydro to "pay later").

~~210. The Minnesota Legislature has specifically addressed cost recovery for transmission assets, providing substantial detail and direction to the Commission regarding that cost recovery.[226] The Legislature enacted these "transmission cost adjustment" provisions specifically for the purpose of encouraging new transmission construction, by removing the financial disincentive to utilities of pursuing such major construction projects under traditional ratemaking.[227]~~

~~211. The traditional ratemaking approach allowed for AFUDC but deferred any utility recovery of costs until the asset was "used and useful" and placed into the utility's rate base.[228]~~

~~212. Minnesota Statutes now provide that a utility may file for a transmission cost adjustment that:~~

> ~~provides a current return on construction work in progress, provided that recovery from Minnesota retail customers for the allowance for funds used during construction is not sought through any other mechanism.[229]~~

~~213.~~225. While the~~The~~ Commission has ~~consistently~~ approved transmission cost recovery ("TCR") filings that provide for "a current return on construction work in progress," ~~and to deny the ability to make such a filing would mark a significant departure from Commission precedent.~~[230] prior to Mr. Kollen's testimony in this proceeding, no party has ever challenged the basis for current recovery of CWIP.

~~214. On July 12, 2007, Minnesota Power requested Commission approval of a TCR Rider consistent with Minn. Stat. § 216B.16, subd. 7b.[231] The Department recommended approval of Minnesota Power's petition. In response to Minnesota Power's request to recover a current return on construction work in progress for two transmission projects, the Department agreed with Minnesota Power's proposed methodology. In its December 7, 2007 Order, the Commission approved Minnesota Power's Transmission Cost Recovery Rider and allowed the Company to begin collecting~~

~~226 Minn. Stat. § 216B.16, subd. 7b.~~
~~227 Ex. 35, p. 12 (McMillan Rebuttal).~~
~~228 *Id.*~~
~~229 Minn. Stat. § 216B.16, subd. 7b (b) (5).~~
230 Ex. 57, p. 6 (Johnson Surrebuttal).
~~231 MPUC Docket No. E-015/M-07-965.~~

~~rates that included a current return on construction work in progress effective January 1, 2008.~~[232]

~~215. On June 23, 2009, the Commission issued an Order approving Minnesota Power's 2009 TCR Rider.~~[233] ~~On May 11, 2011, the Commission issued an Order approving Minnesota Power's 2010 TCR Rider.~~[234] ~~On November 12, 2013, the Commission granted the Company's petition for approval of its 2011 TCR Rider.~~[235] ~~The Company's 2014 TCR Rider is currently pending before the Commission.~~[236]

~~216. In every Commission Order to date, Minnesota Power has been allowed to recover a current return on construction work in progress on transmission projects that have not been placed in-service, consistent with Minn. Stat. § 216B.16, subd. 7b(b)(5).~~

226. No party has submitted evidence that requiring~~Requiring~~ AFUDC treatment of Project construction costs ~~could also have~~would adversely impacts~~s to~~ ratepayers or Minnesota Power.

227. Minnesota Power alleges that providing ~~Providing~~ a current return on CWIP ~~provides~~ would provide customers a lower overall capital cost of approximately $55 million in nominal dollars compared to recording AFUDC, meaning lower overall capital costs to ratepayers.[237] However, Department witness Mr. Johnson disagreed, stating that a current return on CWIP in lieu of capitalizing AFUDC costs during the construction period "does not necessarily result in a benefit to ratepayers."[238] Similarly, Mr. Johnson stated that precluding a current return on CWIP would delay cost recovery until the Project is placed in service; however "such a delay would not necessarily result in a detriment to ratepayers."[239]

228. Given the timing delay in recovery under these two methods, a number of assumptions would be necessary to draw any definitive conclusion as to the net impact on ratepayers.[240] Thus, it is unclear, on a net present value basis, whether current recovery of CWIP or the accrual of AFUDC would cost ratepayers more over the life of the Project.

~~232 *Id.*, p. 1.~~
~~233 MPUC Docket No. E-015/M-08-1176~~
~~234 MPUC Docket No. E-015/M-10-799.~~
~~235 MPUC Docket No. E-015/M-11-695.~~
~~236 MPUC Docket No. E-015/M-14-337.~~
237 Ex. 35, p. 13 (McMillan Rebuttal); Ex. 57, p. 7 (Johnson Surrebuttal).
238 Ex. 57, p. 7 (Johnson Surrebuttal).
239 Ex. 57, p. 7 (Johnson Surrebuttal).
240 Ex. 57, pp. 7-9 (Johnson Surrebuttal).

229. Minnesota Power will fully recover its construction costs under either a current return on CWIP or an AFUDC approach.[241]

~~217.~~230. Because Minnesota Power has not shown that any party would be harmed if the Commission required it to accrue AFUDC and LPI, which represents over 50% of Minnesota Power's customers by revenue, has provided a reasoned analysis challenging the appropriateness of current recovery on CWIP in this case, the ALJ recommends that the Commission direct Minnesota Power to accrue AFUDC for the Project.

~~218. Requiring AFUDC treatment of construction costs also creates the possibility of "rate shock" to customers once the Project is placed in service.[242] Compared to AFUDC treatment, allowing a return on CWIP gradually phases in rate increases rather than creating a one-time rate adjustment for the entirety of the Project.[243]~~

~~219. Requiring AFUDC treatment of Project construction costs would severely harm Minnesota Power's cash flow, which in turn can lower the Company's financial ratings and impose additional costs on ratepayers due to the higher cost of capital.[244] The Department noted that while these harms are difficult to measure, the now standard recovery of these costs through a return on CWIP may bring ratepayer benefits due to the Company's improved cash flow and stronger financial rating.[245]~~

2. ~~Mandating~~ Rider Recovery of ~~All~~ Project Costs

~~220.~~231. In direct testimony, Mr. Kollen also recommended that the Commission ~~act now to require~~direct Minnesota Power to recover all Project costs through a TCR ~~R~~rider, rather than through base rates.[246] The foundation for Mr. Kollen's recommendation was that customers should pay no more and no less than the actual costs of the Project as those costs are incurred, taking into account any "must-take fee" revenues under the ROAs and any MISO revenue credits that the Project may be eligible for.[247] None of those changes in the revenue requirement would be captured in a timely manner if the costs were recovered through base rates.

[241] Ex. 50, pp. 20, 22 (Kollen Direct).
~~[242] Ex. 35, p. 13 (McMillan Rebuttal); Ex. 57, p. 8 (Johnson Surrebuttal).~~
~~[243] Ex. 35, p. 13 (McMillan Rebuttal).~~
~~[244] Id.; V. 1, pp. 68-70 (McMillan).~~
~~[245] Ex. 57, pp. 8-9 (Johnson Surrebuttal).~~
[246] Ex. 50, pp. 4, 24-25 (Kollen Direct).
[247] Ex. 50, pp. 24-25 (Kollen Direct).

~~221.~~232. Minn. Stat. § 216B.16, subd. 7b(b)(9) ~~While the statutes~~ allows for recovery of transmission costs through a TCR rRider.~~, the statutes do not require such recovery in perpetuity~~. ~~Rather, the transmission cost adjustment statute specifically provides that a TCR Rider shall remain in place until "costs have been fully recovered or have otherwise been reflected in the utility's general rates."~~[248]

~~222.~~233. The Commission has never mandated recovery of transmission costs only through a TCR ~~R~~rider.[249]

~~223. It~~ Minnesota Power argued that ~~is possible that~~ better ratemaking outcomes may be achieved for customers by addressing Project costs through a traditional general rate case.[250] ~~For example, a rate case would re-examine the issue of wholesale/retail allocation and may provide benefits to retail customers.~~[251] ~~Further, the transmission rider would use Minnesota Power's last approved return on equity ("ROE") rather than re-examining and resetting an appropriate ROE going forward.~~[252]

234. Minnesota Power also argued that if~~If~~ the Commission mandates recovery solely through a TCR ~~R~~rider, the Commission would essentially be pre-determining rate recovery of the Project over ~~the next 55 years —~~the expected service life of the Project.[253] However, directing Minnesota Power to recover Project-related costs in a TCR rider does not pre-determine rate recovery. Rather, it pre-determines the docket in which rate recovery is addressed.

~~224.~~235. Given the numerous protections afforded by, and the transparency associated with, rider filings, the Commission should direct Minnesota Power to require TCR rider recovery for at least the first five years following the date the Project is placed in service, after which the Commission would reevaluate its decision.

3. Cost Allocations

~~225.~~236. In direct testimony, Mr. Kollen also recommendeds~~s~~ that the Commission allocate rate increases associated with the Project to customer classes based on base revenue, excluding fuel and other riders in order to partially remedy existing interclass subsidies currently provided by the large power class to other classes as a result of ~~pre-determine the allocation of costs among classes of customers, before a cost~~

~~248 Minn. Stat. § 216B.16, subd. 7b(b)(9).~~
249 Ex. 57, pp. 10-11 (Johnson Surrebuttal).
250 Ex. 34, p. 14 (McMillan Rebuttal); Ex. 57, p. 10 (Johnson Surrebuttal).
~~251 Ex. 34, p. 14 (McMillan Rebuttal).~~
~~252 *Id.*~~
253 Ex. 57, p. 10 (Johnson Surrebuttal).

~~recovery proceeding has been initiated. Mr. Kollen believes such action is necessary "to partially remedy the subsidies provided by the LP class to other classes" that resulted from~~ the Commission's most recent Minnesota Power general rate case decision.[254]

237. Cost allocation matters are typically addressed in cost recovery or rate case proceedings.[255] However, all parties typically given notice to such proceedings are also parties to this proceeding and have had the opportunity to comment on LPI's recommendation. Therefore, it would be administratively efficient to address the cost allocation matters raised by Minnesota Power in its CON Application and addressed by LPI in this proceeding~~Cost allocation and ratemaking involves both fact and policy decisions best left to those future cost recovery proceedings, where all customer classes are on notice that ratemaking decisions will be made~~.

~~226.~~238. The Company's plan to seek recovery based on allocations using the D-02 transmission demand allocation factor for the cost of the Project will perpetuate the present subsidies reflected in base rates.[256] Thus, the Commission should partially remedy the subsidies provided by the large power class to other classes in this proceeding by allocating the rate increases associated with the Project to customer classes based on base revenue, excluding fuel and other riders.

CONCLUSIONS OF LAW

1. The Commission and ALJ have jurisdiction to consider Minnesota Power's Application for a CON.

2. The Commission determined that the CON Application was substantially complete and accepted the CON Application on January 8, 2014.

3. Public hearings were conducted in the proposed Project areas for the Project. The public was given an opportunity to appear at the hearings or to submit written comments. The evidentiary portion of the hearing was held in St. Paul, Minnesota.

4. DOC-EERA completed the Environmental Report, following appropriate notice and public information meetings and after receiving public comment.

5. Minnesota Power and DOC-EERA have complied with all applicable substantive and procedural requirements for a CON.

[254] Ex. 50, p. 27 (Kollen Direct).
[255] Ex. 34, pp. 17-18 (McMillan Rebuttal); Ex. 57, p. 14 (Johnson Surrebuttal).
[256] Ex. 50, p. 27 (Kollen Direct).

6. The record in this proceeding demonstrates that Minnesota Power has satisfied the criteria for a CON set forth in Minn. Stat. § 216B.243 and Minn. R. 7849.0120.

7. The record in this proceeding demonstrates that the Project will address Minnesota Power's identified need to provide transmission capacity sufficient to deliver the capacity and power contracted for under the 250 MW Agreements to Minnesota Power and its customers. The record also demonstrates that the Project will provide other benefits~~address multiple needs~~, including (1) ~~enabling the delivery of needed capacity and energy resources to Minnesota Power and its customers; (2)~~ optimizing Minnesota Power's wind energy resources; (~~3~~2) reducing emissions from Minnesota Power's supply portfolio and minimizing the risk of future emissions regulations; (~~4~~3) supporting State and regional energy needs; and (~~5~~4) enhancing the efficiency and reliability of the transmission system.

8. Subject to the qualification set forth below in paragraph 11, ~~N~~no party or person has demonstrated by a preponderance of the evidence that there is a more reasonable and prudent alternative to address ~~those~~ the need~~s~~ met by the Project.

9. The citations to exhibits in the Findings of Fact are not intended to indicate that all evidentiary support in the record has been cited.

10. It is appropriate to condition the CON for the Project on Commission approval of the 133 MW ROAs.

11. In light of the near cost parity of the reasonable natural gas-fired combined cycle alternative, ~~I~~it is appropriate for the Commission to impose a "hard cap" on the Company's recoverable Project costs as set forth in the direct testimony of LPI witness Mr. Kollen ~~specify that: (1) Minnesota Power will be limited to recover in riders only the amount of Project costs proposed in this proceeding; (2) the Company can request recovery of costs above this amount only in a rate case, where those costs will be subject to full prudence review; and (3) Minnesota Power will have the burden of demonstrating the prudency of those additional costs~~.

12. It is appropriate for the Commission to direct Minnesota Power to accrue AFUDC and recover those costs through base rates after the Project is placed in service~~The Commission need not address cost final cost recovery or cost allocation issues in this proceeding~~.

13. It is appropriate for the Commission to direct Minnesota Power to recover all Project costs through a TCR rider, rather than through base rates~~It is not appropriate or consistent with Minnesota law and Commission precedent to set a cost recovery limitation at this time or to require cost recovery exclusively through a rider mechanism~~.

14. It is appropriate for the Commission to direct Minnesota Power to allocate rate increases associated with the Project to customer classes based on base revenue, excluding fuel and other riders~~It is not appropriate to address cost allocation issues when those issues were not noticed for hearing~~.

15. Any of the foregoing Findings that should be treated as Conclusions are hereby adopted as Conclusions.

RECOMMENDATION

Based on the foregoing Findings and Conclusions, IT IS RECOMMENDED that the Minnesota Public Utilities Commission:

> Grant a Certificate of Need to Minnesota Power for the construction of the Great Northern Transmission Line and associated facilities, contingent upon the qualifications set forth above and consistent with the Findings and Conclusions, above.

Dated: December 19, 2014

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CERTIFICATE OF SERVICE

I, Marion R. Lemke, hereby certify that I have this day served a true and correct copy of the following document to all persons at the addresses indicated below or on the attached list by electronic filing, electronic mail, courier, interoffice mail or by depositing the same enveloped with postage paid in the United States Mail at Minneapolis, Minnesota.

1. Post-Hearing Reply Brief of the Large Power Intervenors, including the Affidavit of Lane Kollen;
2. Redline of Large Power Intervenors' Comments to Minnesota Power's Proposed Findings of Fact, Conclusions of Law and Recommendation (Public version); and
3. Redline of Large Power Intervenors' Comments to Minnesota Power's Proposed Findings of Fact, Conclusions of Law and Recommendation (Trade Secret version)

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
OAH Docket No. 65-2500-31196

Dated this 16th day of January, 2015.

/s/ Marion R. Lemke
Marion R. Lemke