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

STOEL RIVES LLP

Andrew P. Moratzka
33 South Sixth Street, Suite 4200
Minneapolis, MN 55402

Chad T. Marriott
900 SW Fifth Ave., Suite 2600
Portland, OR 97204

TABLE OF CONTENTS

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

[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]

---

[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]

---

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.

---

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

[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.

---

[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,

STOEL RIVES LLP

/s/ Andrew P. Moratzka

Andrew P. Moratzka
33 South Sixth Street, Suite 4200
Minneapolis, MN 55402
Tele: 612-373-8822
Fax: 612-373-8881

Chad T. Marriott
900 SW Fifth Ave., Suite 2600
Portland, OR 97204
Tele : 503-294-9339
Fax : 503-220-2480

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