BEFORE THE OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION

STATE OF MINNESOTA

In the Matter of the Request by Minnesota Power

For a Certificate of Need for the

Great Northern Transmission Line

OAH Docket No. 65-2500-31196

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

Exhibit _______

Rebuttal Testimony and Exhibits of

DAVID J. MCMILLAN

October 24, 2014

MR. DAVID J. MCMILLAN

OAH Docket No. 65-2500-31196

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

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is David J. McMillan and my business address at Minnesota Power is 30 West Superior Street, Duluth, Minnesota 55802.

Q. What are your current positions with Minnesota Power and ALLETE?

A. I am the Executive Vice President – Minnesota Power and Senior Vice President – External Affairs – ALLETE.

Q. Have you previously filed testimony in this proceeding?

A. Yes. I filed Direct Testimony providing an overview of Minnesota Power's Certificate of Need Application for the Great Northern Transmission Line (also "Project") and the Company's overall approach to this Project, a discussion of the Project ownership and Project participants, a discussion of the potential retail rate impacts of the Project on Minnesota Power's customers, and a summary of the key factors supporting the issuance of a Certificate of Need for this Project.

Q. What is the purpose of your Rebuttal Testimony?

A. My Rebuttal Testimony addresses certain matters raised in the testimonies of the two other parties filing Direct Testimony in this proceeding – the Department of Commerce ("Department") and the Large Power Intervenors ("LPI"). Residents and Ratepayers Against Not-so-Great Northern Transmission ("RRANT") did not file any testimony. The Department filed testimony of Dr. Rakow and Mr. Shah.

After reviewing Mr. Shah's testimony, Minnesota Power sees no need for correction or other comment. Department witness Dr. Stephen Rakow and LPI witness Lane Kollen do raise certain matters or provide recommendations that require responses. Specifically, I will address the following matters raised by Dr. Rakow:

- An update on the status of the Keeyask and Conawapa generating stations in Manitoba, as well as an update on the Canadian portion of the new tie-line that will meet the Project at the United States-Canadian border;
- The request for clarification on certain ownership and financial responsibility issues;
- Further discussion of Minnesota Power's intentions with respect to recovery of its portion of the capital costs of the Project; and
- The request that the Minnesota Public Utilities Commission ("Commission") order Minnesota Power to use the Commission's externality values in all future Certificates of Need.

I will also address the following matters discussed in Mr. Kollen's testimony:

- His recommendation that the Commission make the granting of a Certificate of Need for the Project conditioned upon Commission approval of the 133 MW Energy Sale Agreement and Energy Exchange Agreement (collectively, the "133 MW Renewable Optimization Agreements") between Minnesota Power and Manitoba Hydro;

- The recommendation to put a "hard cap" on total costs of $750 million in "as spent" dollars and that the Commission "ensure" that ratepayers are only obligated for 28.3% of the total costs of the Project;
- His recommendation that the Commission require allowance for funds used during construction ("AFUDC") treatment of construction costs during the construction period;
- The recommendation to require rider recovery of the Project costs, rather than recovery through base rates; and
- His recommendation that the Commission address inter-class subsidy issues by allocating costs based on base revenues excluding fuel or other riders.

Q. Do other Minnesota Power witnesses address any matters raised by other witnesses?

A. Yes. Minnesota Power witness Donahue will address certain other items discussed by Dr. Rakow.

II. RESPONSE TO DR. RAKOW

Q. Please provide an update regarding the status of activities in Manitoba concerning new generating stations and the Canadian portion of the new tie-line.

A. As I discussed in my Direct Testimony, while Minnesota Power is developing the Project, Manitoba Hydro is simultaneously developing the Canadian portion of these major new transmission facilities, along with the construction of the 695 MW Keeyask Generating Station, being undertaken by the Keeyask Hydropower Limited Partnership ("KHLP") -- a partnership between the Tataskweyak Cree Nation, War Lake First Nation, York Factory First Nation, Fox Lake Cree Nation, and Manitoba Hydro to develop this facility in northern Manitoba.

The Manitoba-Minnesota Transmission Line Project ("MMTP") is the Canadian portion of the new 500 kV transmission line that will interconnect with the Great Northern Transmission Line. The MMTP is scheduled to be placed in service in mid-2020. On July 2, 2014, the Province of Manitoba accepted the recommendation from the Manitoba Public Utilities Board that Manitoba Hydro should proceed with developing the MMTP, subject to further federal and provincial regulatory approvals. Manitoba Hydro has completed two rounds of public engagements and a preferred route has been selected that will be subject to a final round of public engagement scheduled to commence in January 2015. Feedback from the final round of public engagement along with environmental assessment work will be utilized by Manitoba Hydro to finalize the route selection and complete the regulatory submissions by the summer of 2015.

Regarding Keeyask, Manitoba Hydro is managing the construction of the project and will be responsible for operating the generating station on behalf of the KHLP. Manitoba Hydro and the KHLP continue to work towards meeting a 2019 in-service date for the Keeyask Generating Station and in this regard a number of key milestones have already been achieved, including:

- In March 2014, the general civil contract was awarded to a limited partnership between Bechtel Canada Co., Barnard Construction of Canada Ltd., and EllisDon Civil Ltd. The general civil contract includes rock excavation, concrete for the powerhouse and spillway, earthen structures, electrical and mechanical work and the construction and removal of temporary cofferdams to manage river flows during construction.
- On July 2, 2014, the Province of Manitoba issued an environmental license to the KHLP for the construction of the 695 MW Keeyask Generating Station. The Province's decision was based on favorable recommendations received from (i) a special panel of the Manitoba Public Utilities Board responsible for reviewing Manitoba Hydro's development plans and (ii) the

Clean Environment Commission that was responsible for performing an independent environmental review of the Keeyask project.

- On July 16, 2014, the KHLP officially commenced construction of the Keeyask Generating Station as work started on the quarry cofferdam. Materials from the quarry will be used to construct other cofferdams needed to create dry working areas within the riverbed and used in the concrete required for construction of the powerhouse and spillway.

Finally, both our Application and my Direct Testimony discussed the potential development of the 1,485 MW Conawapa generating station, with an in-service date of approximately 2026. As I noted in my Direct Testimony, Manitoba has not determined to move forward with Conawapa at this time. On July 2, 2014, the Province of Manitoba accepted the Public Utilities Board recommendation that pre-construction expenditures planned for the Conawapa Generating Station will be frozen until more export sales are confirmed and an updated business case is brought back for independent review. The Province of Manitoba has asked Manitoba Hydro to advance its efforts on firming up additional export power sales and has confirmed that Conawapa remains vitally important to Manitoba's long-term energy future.

Q. At pages 30 – 36 of his Direct Testimony, Dr. Rakow discusses the intended ownership and financial responsibilities associated with the Project. Has he fairly described these matters?

A. In general, yes. As Dr. Rakow notes, while Minnesota Power will have 51% ownership of the Project, the Company will be responsible for financing just 46% of the costs, due to a 5% Contribution in Aid of Construction ("CIAC") to be paid by Manitoba Hydro. Moreover, Manitoba Hydro will cover an additional 17.7% of the financial responsibility for the construction costs of the Project through payment of the Monthly Must Take Fee included in the 133 MW Renewable Optimization Agreements discussed in my Direct Testimony, bringing Minnesota Power and its ratepayers' ultimate financial responsibility for the capital expenses associated with the Project down to 28.3%. Dr. Rakow displays this revenue responsibility, and the other components making up the full 100% revenue requirements responsibility, in his Table 3 on page 36 of his Direct Testimony (Mr. Donahue addresses this Table in his Rebuttal Testimony, including a necessary clarification regarding operating and maintenance cost responsibility). Dr. Rakow also requested confirmation or clarification of certain items in Minnesota Power's Rebuttal Testimony.

Q. On what matters did Dr. Rakow seek confirmation or clarification?

A. First, Dr. Rakow sought confirmation of the manner in which Minnesota Power intends to handle the 17.7% share of the capital cost revenue requirement responsibility to be covered by Manitoba Hydro through the scheduling fee included in the 133 MW Renewable Optimization Agreements. At page 33 of his testimony, Dr. Rakow accurately states that Minnesota Power intends to propose that this 17.7% share of the capital costs be placed into rate base or into the Transmission Cost Recovery Rider, with the Monthly Must Take Fee paid by Manitoba Hydro applied as an offset.

Dr. Rakow also requested that Minnesota Power discuss how it envisions cost recovery would work in the event Manitoba Hydro assigns its minority ownership in the Project to another Minnesota Midcontinent Independent System Operator, Inc. ("MISO") transmission owner, that the Company confirm the revenue requirements responsibility to be borne by Minnesota Power ratepayers, and that the Company clarify certain operations and maintenance cost recovery matters. Mr. Donahue addresses these issues in his Rebuttal Testimony.

Finally, Dr. Rakow requested that the Commission order Minnesota Power to use the Commission's externality values in all future Certificates of Need. Minnesota Power will apply these values in future Certificates of Need. Minnesota Power supports Dr. Rakow's conclusions that applying externality values to the Project demonstrates additional benefits of the Project.

III. RESPONSE TO MR. KOLLEN

Q. LPI witness Mr. Kollen does not challenge the need for the Project, but recommends that Commission approval of the Certificate of Need be "contingent" upon Commission approval of the 133 MW Renewable Optimization Agreements between Minnesota Power and Manitoba Hydro and Federal Energy Regulatory Commission ("FERC") approval of the Facilities Construction Agreement ("FCA"). How does Minnesota Power respond?

A. The 133 MW Renewable Optimization Agreements provide substantial benefits to Minnesota Power and its ratepayers and are a central piece of the overall benefits of the Project. These 133 MW Renewable Optimization Agreements will be filed with the Commission in the very near future and Minnesota Power will submit its petition for approval of the 133 MW Renewable Optimization Agreements to the record of this docket once that filing occurs.

The FCA also provides substantial benefits to Minnesota Power and its ratepayers in the form of the 5% CIAC discussed above. As Mr. Donahue discusses, the FCA has now been filed with FERC.

Given the importance of both of these 133 MW Renewable Optimization Agreements to the overall Project and the Project economics, Minnesota Power has no objection to requiring their approval.

Q. Mr. Kollen also recommends that the Commission establish a "hard cap" in "as spent" dollars on the overall capital cost of the Project as estimated by Mr. Kollen and that the Commission ensure that ratepayers are only obligated to pay 28.3% of that amount. Is such a "hard cap" reasonable?

A. No. A cost "cap" of the type suggested by Mr. Kollen is not appropriate as part of a Certificate of Need approval and goes beyond any past Commission orders.

First, Minnesota Power has provided a range of capital costs as set forth in Mr. Donahue's testimony. This range is appropriate given that a final route and any route permit conditions have not been decided for this Project. Second, the capital cost caps recently imposed by the Commission for Minnesota Power's Boswell 4 Project as well as for other transmission projects that require a Certificate of Need are not "hard caps," as recommended by Mr. Kollen but merely act to limit Minnesota utilities' ability to obtain current cost recovery outside of a general rate case. For example, in the Commission's November 4, 2013 order approving Minnesota Power's mercury plan to retrofit Boswell Unit 4 in Docket No. E-015/M-12-920, the Commission stated: "To protect ratepayers from potential cost overruns, the Commission will cap the total amount that Minnesota Power may recover through the Boswell 4 rider at the amount stated in the Company's petition." Order at 7. The Commission capped only the amount Minnesota Power may recover through the rider; it did not impose a cap on total recovery, including potential rate case recovery.

Second, to my knowledge, the Commission has not imposed a cost-cap as part of the Certificate of Need approval and it is not reasonable to preemptively limit future cost recovery as a part of this docket. The Commission will continue to have the ability to assess the prudence of the costs incurred in developing the Project and does not need to artificially "cap" the costs at this time

Third, while the Commission's past practice of limiting <u>current</u> cost recovery does provide incentives to manage the cost of the Project, Minnesota Power's larger obligations to limit impacts on customers has driven the development of this Project. The Company's efforts in this regard include assuring that all benefits from the 133 MW Renewable Optimization Agreements (including environmental benefits, as discussed in Mr. Rudeck's Direct Testimony) flow through to customers and allocating a significant portion of Project's capital costs to Manitoba Hydro lessening the impact of the Project on rates. These unique contractual agreements with Manitoba Hydro already provide substantial ratepayer benefit and protection.

Finally, Minnesota Power has included standard contingencies in its Project estimates. Given the geography, long-lead time, and length and size of this Project, those are reasonable contingencies and Minnesota Power should not be penalized by a "hard cap" should some of these contingencies prove necessary.

Q. Mr. Kollen further recommends that the Commission not allow a current return on Construction Work in Progress ("CWIP") but instead mandate that the Company accrue allowance for funds used during construction ("AFUDC"). Is this recommendation appropriate?

A. No. Mr. Kollen's recommendation has several flaws.

First, while Minnesota Power has worked to be transparent about cost recovery matters, cost recovery treatment is not an issue that needs to be decided in the Certificate of Need docket. Indeed, it would be premature and inappropriate to do so at this time.

Second, under Minnesota Statutes Section 216B.16, subd. 7b, high voltage transmission projects that receive a Certificate of Need are specifically eligible for current cost recovery during construction. The Minnesota Legislature granted utilities this authority to incentivize new transmission construction, such as the Project, in lieu of the old paradigm that prohibited recovery of the costs of a new asset until it was "used and useful" and placed into rate base.

Third, a current return on CWIP provides customers a lower overall capital cost. As shown in Ex. __ (DJM-R), Schedule 1, Minnesota Power estimates the overall capital savings of CWIP treatment to be approximately $55 million in nominal dollars compared to recording AFUDC. Precluding a current return on CWIP simply delays cost recovery until the Project is in-service. This delay will increase total overall revenue requirements for Minnesota Power's customers.

Fourth, Minnesota Power disagrees with Mr. Kollen's statement that the Project "has value only after it is constructed and placed in-service." Given the contractual requirements in the Power Purchase Agreements with Manitoba Hydro and the certainty that those requirements are met, the long lead time it takes to permit and construct a project and the significant capital cost outlay required to construct a 500 kV line, Minnesota Power sees significant value to the Company and its ratepayers prior to the date when the Project is placed in-service. Other benefits from a return on CWIP include reduced rate shock for customers because rate increases are gradually phased in during construction, and improved cash flow for the utility which will in turn support stronger financial ratings and lower capital costs for this Project and all other capital projects.

Q. Does Minnesota Power support Mr. Kollen's recommendation that the Commission only allow rate recovery of Project costs through the

Transmission Cost Recovery Rider or some other rider, rather than through base rates?

A. No. Minnesota Power agrees that the Project will be <u>eligible</u> under Minnesota Statute Section 216B.16, subd. 7b for the Transmission Cost Recovery Rider if the Commission approves the Certificate of Need. Minnesota Power also agrees that the benefits from the Monthly Must Take Fee and other revenues Minnesota Power receives should be credited to ratepayers. However, once the Project is built and in service, better ratemaking outcomes may well be achieved for customers by addressing this major new asset addition through a traditional general rate case. For example, a rate case would re-examine the issue of wholesale/retail allocation and may provide benefits to retail customers. Further, the transmission rider would use Minnesota Power's last approved return on equity ("ROE") rather than re-examining and resetting the appropriate ROE going forward. In addition, from the Company's perspective, under current Commission precedent, utilities are not allowed to recover internal capital costs through rider mechanisms. If the Project must stay in Minnesota Power's transmission rider, there will not be an opportunity to recover these internal costs. Also, if the Commission limits <u>current</u> cost recovery to a set capital range, then Minnesota Power will not have the opportunity to recover any future capital costs.

Q. Mr. Kollen requested the Company provide details of cost allocation, rate design and rate impacts on customer classes. Did the Company prepare these details?

A. Yes. However, I must first note that the Company does not agree that cost allocations or rate design matters belong in a Certificate of Need proceeding, as I discuss further, below. Nonetheless, in order to be responsive to Mr. Kollen's request, the Company provides information on two alternative examples of cost allocation. For both examples the Company allocates the revenue requirements to the Minnesota retail jurisdiction using the D-02 transmission demand allocation factor from the Company's last rate case. In the first example, the jurisdictional revenue requirements are allocated to the Large Power ("LP") Class and all other Non-LP Classes using the D-02 transmission demand class allocation factors. Under this approach, as Mr. Lane correctly states in his testimony, the greatest percentage increase would fall on the LP Class. The allocation of revenue requirements to jurisdiction and to customer classes under this approach is shown in Ex. __ (DJM-R), Schedule 2, Table 1.

The second example was developed after clarifying the Company's understanding of Mr. Kollen's recommendation on allocating revenue requirements. Under this second approach, the jurisdictional revenue requirements are apportioned to customer class on base revenue so that all customer classes have the same average rate increase. The allocation of revenue requirements to jurisdiction and to customer classes for this example is shown in Ex. __ (DJM-R), Schedule 2, Table 2.

Q. Would you please explain the rate design for the first example?

A. Yes. As shown in Table 1, the rate design for the LP Class incorporates demand ($/kW-month) and energy (¢/kWh) adders that recover costs in a manner that preserves existing LP base rate design. Specifically, the LP revenue requirements would be split between demand and energy based on LP's base rate demand and energy revenue split of approximately 60% demand and 40% energy from Minnesota Power's most recent retail rate case. The LP demand rate adder would be calculated as 60% of the projected LP revenue requirement divided by the LP Class Billing Demand (kW-month) from Minnesota Power's most recent budget. The LP energy rate adder will be calculated as 40% of the projected LP revenue requirement divided by the LP energy (kilowatt-hour) sales from Minnesota Power's most recent budget. The rate design for the other Non-LP Classes is calculated as a single average energy-based (¢/kWh) charge consisting of the revenue requirements allocated to the other Non-LP Classes divided by the total energy (kWh) sales of the other Non-LP Classes from Minnesota Power's most recent budget.

Q. Would you please explain the rate design for the second example?

A. Yes. As shown in Table 2, the rate design for the LP Class is identical to the first alternative. For all other Non-LP Classes, the rate design is separate average energy-based (¢/kWh) charge for each class.

Q. What are the estimated rate impacts of the two examples?

A. The estimated rate impacts for all customer classes under the first and second examples are shown for the years 2020, 2021 and 2022 in Ex. __ (DJM-R), Schedule 2, Tables 3 and 4, respectively. Under the first alternative the Company estimates the increase in years 2020, 2021 and 2022 will be 2.96%, 2.63%, and 2.53% for residential customers and 4.63%, 4.09%, and 3.94% for LP customers, respectively. In the second alternative the Company estimates the increase for the years 2020, 2021 and 2022 will be 3.98%, 3.54%, and 3.40% for all customer classes.

Q. Finally, does the Company agree with Mr. Kollen that the rate making issues should be decided by the Commission in this case?

A. No. Ratemaking involves both fact and policy decisions best left to future cost recovery proceedings. Again, Mr. Kollen recommends that the Commission essentially pre-determine items that can and will be addressed in subsequent proceedings such as a rate case or a "factor" filing specific to Minnesota Power's Transmission Cost Recovery Rider. The purpose of this proceeding is to determine whether Minnesota Power has demonstrated the need for the Project, not to address other issues parties may have from past or future proceedings. As I discussed in my Direct Testimony, the Company has met all the criteria necessary for the granting of a Certificate of Need. Therefore, the Company continues to respectfully request that the Commission grant it a Certificate of Need so that it may proceed with the Great Northern Transmission Line Project.

Q. Does this complete your Rebuttal Testimony?

A. Yes.

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Exhibit _____ (DJM-R), Schedule 1, Page 1 of 1

Great Northern Transmission Line
Return on CWIP vs. AFUDC (nominal dollars)

Summary of Project Costs assuming a Return on CWIP

Total Project					
Capital Expenditures	**749,737,208**	Total Project =	750,556,219	(CapEx + AFUDC)	
Less MH CIAC	**(37,527,811)**	MH CIAC =	37,527,811		5.00%
Less Joint Owner Payments	**(367,772,547)**	Joint Owner Responsibility =	367,772,547		49.00%
AFUDC	**819,011**	MP Portion =	345,255,861		46.00%

Summary of Project Costs assuming AFUDC

Total Project					
Capital Expenditures	**749,737,208**	Total Project =	805,723,778	(CapEx + AFUDC)	
Less MH CIAC	**(37,527,811)**	MH CIAC =	37,527,811		4.66%
Less Joint Owner Payments	**(367,772,547)**	Joint Owner Responsibility =	367,772,547		45.64%
AFUDC	**55,986,570**	MP Portion =	400,423,420		49.70%

Notes:

1/ The Contribution In-Aid of Construction (CIAC) and Joint Owner Payments are made as construction progresses, so AFUDC under the second scenario would only accumulate on Minnesota Power's portion of the total project.

2/ Return on CWIP results in an estimated capital savings of $55,167,559 (55,986,570 - 819,011) compared to recording AFUDC.

Minnesota Power
Great Northern Transmission Line CoN Support
Summary: Revenue Requirements, Cost Allocation and Rate Design
Alternative 1 Based on D-02 Allocator

	Allocations 1/	2020	2021	2022
Revenue Requirements ($)				
Total Customer Revenue Requirements	100.00%	33,083,726	29,379,774	28,218,155
MN Jurisdiction	77.57%	25,663,046	22,789,891	21,888,823
Large Power	48.49%	16,041,968	14,245,959	13,682,701
All Other Classes	29.08%	9,621,078	8,543,932	8,206,122
2015 Billing Units 2/				
Large Power	kW - month	716,608	716,608	716,608
	kWh	6,037,136,000	6,037,136,000	6,037,136,000
All Other Classes	kWh	3,245,508,000	3,245,508,000	3,245,508,000
Billing Factors 3/				
Large Power	$/kW - month	1.12	0.99	0.95
	¢/kWh	0.106	0.094	0.091
All Other Classes	¢/kWh	0.296	0.263	0.253

Notes:
1/ The D-02 allocator is from MP's 2009 MPUC rate case Docket No. E-015/GR-09-1151.
2/ 2015 budget.
3/ For CoN rate impact using an average demand and energy rate for Large Power. In upcoming cost recovery filing, the LP rate design would be a demand rate adder ($/kW-month) and an energy adder (¢/kWh). The LP allocated costs are to be split between demand and energy on the 2010 base rate demand and energy revenue split of approximately 60% demand and 40% energy per results of MP's most recent MPUC rate case (Docket No. E015/GR-09-1151). All other retail classes will have an energy adder (¢/kWh).

Table 2

Minnesota Power
Great Northern Transmission Line CoN Support
Summary: Revenue Requirements, Cost Allocation and Rate Design
Alternative 2 Based on Revenue Allocator

	2015 Budgeted kWh /1	Estimated Current Rate	Estimated Revenue	Percent of Revenue Allocator
Residential	1,099,130,000	9.995	109,862,831	17.04%
General Service	662,735,000	9.990	66,209,609	10.27%
Large Light & Power	1,425,241,000	8.081	115,169,623	17.87%
Large Power	6,037,136,000	5.740	346,507,468	53.76%
Municipal Pumping	35,985,000	9.149	3,292,218	0.51%
Lighting	22,417,000	15.657	3,509,779	0.54%
			644,551,528	100.00%

	Allocations 2/	2020	2021	2022
Revenue Requirements ($)				
Total Customer Revenue Requirements	100.00%	33,083,726	29,379,774	28,218,155
MN Jurisdiction	77.57%	25,663,046	22,789,891	21,888,823
	Allocations 3/			
Residential	17.04%	4,374,227	3,884,502	3,730,917
General Service	10.27%	2,636,159	2,341,023	2,248,463
Large Light & Power	17.87%	4,585,519	4,072,139	3,911,134
Large Power	53.76%	13,796,317	12,251,724	11,767,314
Municipal Pumping	0.51%	131,081	116,405	111,803
Lighting	0.54%	139,743	124,098	119,191
		25,663,046	22,789,891	21,888,823
Billing Factors				
Residential	¢/kWh	0.398	0.353	0.339
General Service	¢/kWh	0.398	0.353	0.339
Large Light & Power	¢/kWh	0.322	0.286	0.274
Large Power	¢/kWh	0.229	0.203	0.195
Municipal Pumping	¢/kWh	0.364	0.323	0.311
Lighting	¢/kWh	0.623	0.554	0.532

LP Factor Demand-Energy Split 4/

LP Billing Units	2015 Budgeted Billing Units /1
kW - month	716,608
kWh	6,037,136,000

LP Factors		2020	2021	2022
	$/kW - month	0.96	0.85	0.82
	¢/kWh	0.091	0.081	0.078

Notes:
1/ 2015 budget.
2/ The D-02 allocator is from MP's 2009 MPUC rate case Docket No. E-015/GR-09-1151.
3/ Percent of Revenue Allocator shown above, designed to give all classes an equal percentage increase.
4/ For CoN rate impact using an average demand and energy rate for Large Power. In upcoming cost recovery filing, the LP rate design would be a demand rate adder ($/kW-month) and an energy adder (¢/kWh). The LP allocated costs are to be split between demand and energy on the 2010 base rate demand and energy revenue split of approximately 60% demand and 40% energy per results of MP's most recent MPUC rate case (Docket No. E015/GR-09-1151). All other retail classes will have an energy adder (¢/kWh).

MINNESOTA POWER
Great Northern Transmission Line
Estimated Average Rate Impacts
Alternative 1 Based on D-02 Allocator

	2020	2021	2022
Minnesota Jurisdictional Revenue Requirement	$25,663,046	$22,789,891	$21,888,823
Rate Class Impacts \1			
Residential (average current rate, cents/kWh)	9.995	9.995	9.995
Increase (cents/kWh)	0.296	0.263	0.253
Increase (%)	2.96%	2.63%	2.53%
Average Impact ($ / month)	$2.40	$2.13	$2.05
General Service (average current rate, cents/kWh)	9.990	9.990	9.990
Increase (cents/kWh)	0.296	0.263	0.253
Increase (%)	2.96%	2.63%	2.53%
Average Impact ($ / month)	$8.24	$7.32	$7.04
Large Light & Power (average current rate, cents/kWh)	8.081	8.081	8.081
Increase (cents/kWh)	0.296	0.263	0.253
Increase (%)	3.66%	3.25%	3.13%
Average Impact ($ / month)	$674.78	$599.55	$576.75
Large Power (average current rate, cents/kWh)	5.740	5.740	5.740
Increase (Demand & Energy Combined) (cents/kWh)	0.266	0.235	0.226
Increase (%)	4.63%	4.09%	3.94%
Average Impact ($ / month)	$133,588	$118,235	$113,859
Municipal Pumping (average current rate, cents/kWh)	9.149	9.149	9.149
Increase (cents/kWh)	0.296	0.263	0.253
Increase (%)	3.24%	2.87%	2.77%
Average Impact ($ / month)	$31.93	$28.37	$27.29
Lighting (average current rate, cents/kWh)	15.657	15.657	15.657
Increase (cents/kWh)	0.296	0.263	0.253
Increase (%)	1.89%	1.68%	1.62%
Average Impact ($ / month)	$1.08	$0.96	$0.93

Notes:

1/ Average current rates are 2015 estimated rates based on Final 2010 TY General Rates in 2009 Rate Case (E-015/GR-09-1151) without riders adjusted to include current rider rates.

Current rider rates include Renewable Resources Rider rates, Transmission Cost Recovery Rider rates, Boswell 4 Emission Reduction Rider rates, current 2014 CPA rate and estimated 2015 FPE.

Average $/month impact based on 2015 budgeted billing units.

MINNESOTA POWER

Great Northern Transmission Line

Estimated Average Rate Impacts

Alternative 2 Based on Revenue Allocator

	2020	2021	2022
Minnesota Jurisdictional Revenue Requirement	$25,663,046	$22,789,891	$21,888,823
Rate Class Impacts \1			
Residential (average current rate, cents/kWh)	9.995	9.995	9.995
Increase (cents/kWh)	0.398	0.353	0.339
Increase (%)	3.98%	3.54%	3.40%
Average Impact ($ / month)	$3.22	$2.86	$2.75
General Service (average current rate, cents/kWh)	9.990	9.990	9.990
Increase (cents/kWh)	0.398	0.353	0.339
Increase (%)	3.98%	3.54%	3.40%
Average Impact ($ / month)	$11.07	$9.83	$9.44
Large Light & Power (average current rate, cents/kWh)	8.081	8.081	8.081
Increase (cents/kWh)	0.322	0.286	0.274
Increase (%)	3.98%	3.54%	3.40%
Average Impact ($ / month)	$733.45	$651.33	$625.58
Large Power (average current rate, cents/kWh)	5.740	5.740	5.740
Increase (Demand & Energy Combined) (cents/kWh)	0.229	0.203	0.195
Increase (%)	3.98%	3.54%	3.40%
Average Impact ($ / month)	$114,969	$102,098	$98,061
Municipal Pumping (average current rate, cents/kWh)	9.149	9.149	9.149
Increase (cents/kWh)	0.364	0.323	0.311
Increase (%)	3.98%	3.54%	3.40%
Average Impact ($ / month)	$39.29	$34.89	$33.51
Lighting (average current rate, cents/kWh)	15.657	15.657	15.657
Increase (cents/kWh)	0.623	0.554	0.532
Increase (%)	3.98%	3.54%	3.40%
Average Impact ($ / month)	$2.28	$2.03	$1.95

Notes:

1/ Average current rates are 2015 estimated rates based on Final 2010 TY General Rates in 2009 Rate Case (E-015/GR-09-1151) without riders adjusted to include current rider rates.

Current rider rates include Renewable Resources Rider rates, Transmission Cost Recovery Rider rates, Boswell 4 Emission Reduction Rider rates, current 2014 CPA rate and estimated 2015 FPE.

Average $/month impact based on 2015 budgeted billing units.