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September 3, 2014

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E015/M-14-349

Dear Dr. Haar,

Attached are the comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

Minnesota Power's Renewable Resources Rider and 2014 Renewable Factor.

The Petition was filed on April 29, 2014 by:

Lori Hoyum
Policy Manager
Minnesota Power
30 West Superior Street
Duluth, MN 55802

As described herein, the Department concludes that Minnesota Power's proposal is reasonable, but suggests an alternative for the Minnesota Public Utilities Commission (Commission) to consider. The Department is available to answer any questions the Commission may have.

Sincerely

/s/ CRAIG ADDONIZIO
Financial Analyst

CA/lt
Attachment

MINNESOTA DEPARTMENT OF COMMERCE

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

COMMENTS OF THE MINNESOTA DEPARTMENT OF COMMERCE DIVISION OF ENERGY RESOURCES

DOCKET NO. E015/M-14-349

I. INTRODUCTION

On April 29, 2014, Minnesota Power (MP or the Company) filed a petition (Petition) with the Minnesota Public Utilities Commission (Commission) requesting recovery of the Minnesota jurisdictional costs of several renewable energy projects via the Company's Renewable Resources Rider (RRR).

MP's RRR was first established in Docket No. E015/M-07-216 to allow for recovery of costs associated with future renewable resource contracts, investments and expenditures, as allowed under Minn. Stat. §216B.1645, subd. 2.[1] The Commission has since approved three updates to MP's RRR, in Docket Nos. E015/M-10-273, E015/M-11-274, and, most recently, E015/M-13-410 (the 2013 RRR Filing), allowing the Company to recover costs associated with its first three Bison Wind Projects.

In its Petition, MP is requesting approval to continue to recover the costs of Bisons 1, 2, and 3, and begin recovering costs related to its fourth Bison wind project, Bison 4.

II. DETAILS OF MP'S PROPOSAL

A. REVENUE REQUIREMENT AND TRACKER BALANCE

MP requests recovery of its estimated 2014 revenue requirements for its Bison Wind Projects, as well as recovery of under-collected amounts in the past, which MP accumulates in a tracker.

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[1] See the Commission's May 11, 2007 Order in Docket No. E015/M-07-216.

MP proposes to allocate a portion of its total company costs to the Minnesota jurisdiction using the allocators from its last rate case.[2] Table 1 below summarizes the total Minnesota-jurisdictional amount for which the Company requests recovery in its Petition.

**Table 1:
Summary of Costs for Which
Company Requests Recovery
($ Millions)**

2014 Revenue Requirement	51.7
Tracker Balance	34.1
Total	85.8

Source: Petition, Exhibit B-1, Page 1

MP proposes to separate its various retail customer classes into two groups, one consisting solely of the Company's Large Power (LP) customer class, and one consisting of all other retail classes. MP proposes to allocate the 2014 revenue requirement ($51.7 million) between the two groups using its Power Supply Production and Power Supply Transmission demand allocators from its most recent rate case, Docket No. E015/GR-09-1151.[3]

MP allocates its tracker balance using a backwards-looking historical analysis that compares actual revenue requirements to actual cash collections from each customer group, and adds the differences to each group's respective tracker balance.[4] In its Petition, MP first allocates its actual 2013 revenue requirement between the two groups using the Power Supply Transmission Production Demand allocator from its most recent rate case (the same allocator used to allocate 2014 revenue requirements). The Company then calculates the difference between each group's allocated 2013 revenue requirement and its actual 2013 cash collections. These differences are then added to each group's existing tracker balance, which was calculated in prior RRR petitions in a similar manner.[5]

B. RATE DESIGN

The Company proposes to use the same rate design approved in its last RRR filing in the instant filing. MP proposes to calculate demand and energy adders for its LP customer class, and to calculate a single average energy adder for all other retail classes. MP proposes to split the LP customer class' total revenue requirement between demand and energy based on the approximate split used in MP's most recent rate case (60 percent demand, 40 percent energy). The proposed adder for all other retail classes is equal to the

[2] See Petition, page 17.
[3] See Petition, pages 16-17.
[4] See Department Attachment 1.
[5] See Petition, Exhibit B-1, page 2 of 7.

group's total revenue requirement (the sum of the group's allocated 2014 revenue requirement and its tracker balance) divided by MP's estimate of the group's 2014 energy consumption. The demand and energy adders are then calculated using MP's 2014 estimated billing factors.[6]

Table 2 summarizes MP's current and proposed RRR rates.

Table 2:
Summary of Current and Proposed
RRR Rates

		RRR Rates		
		Current	Proposed	Increase
Large Power	Demand (cents/kW - month)	1.700	3.450	103%
	Energy (cents/kWh)	0.163	0.330	102%
All Other Retail Classes	Energy (cents/kWh)	0.614	1.102	79%

Source: Petition, Exhibit B-1, page 1 of 7

III. DEPARTMENT ANALYSIS

A. STATUTORY REQUIREMENTS

Minn Stat. §216B.1645, subd. 2a states that:

> (a) A utility may petition the commission to approve a rate schedule that provides for the automatic adjustment of charges to recover prudently incurred investments, expenses, or costs associated with facilities constructed, owned, or operated by a utility to satisfy the requirements of section 216B.1691, provided those facilities were previously approved by the commission under section 216B.2422 or 216B.243, or were determined by the commission to be reasonable and prudent under section 216B.243, subdivision 9. For facilities not subject to review by the commission under section 216B.2422 or 216B.243, a utility shall petition the commission for eligibility for cost recovery under this section prior to requesting cost recovery

[6] See Petition, Exhibit B-1, page 1 of 7.

for the facility. The commission may approve, or approve as modified, a rate schedule that:

(1) allows a utility to recover directly from customers on a timely basis the costs of qualifying renewable energy projects, including:
  (i) return on investment;
  (ii) depreciation;
  (iii) ongoing operation and maintenance costs;
  (iv) taxes; and
  (v) costs of transmission and other ancillary expenses directly allocable to transmitting electricity generated from a project meeting the specifications of this paragraph;

(2) provides a current return on construction work in progress, provided that recovery of these costs from Minnesota ratepayers is not sought through any other mechanism;

(3) allows recovery of other expenses incurred that are directly related to a renewable energy project, including expenses for energy storage, provided that the utility demonstrates to the commission's satisfaction that the expenses improve project economics, ensure project implementation, advance research and understanding of how storage devices may improve renewable energy projects, or facilitate coordination with the development of transmission necessary to transport energy produced by the project to market;

(4) allocates recoverable costs appropriately between wholesale and retail customers;

(5) terminates recovery when costs have been fully recovered or have otherwise been reflected in a utility's rates.

(b) A petition filed under this subdivision must include:
  (1) a description of the facilities for which costs are to be recovered;
  (2) an implementation schedule for the facilities;
  (3) the utility's costs for the facilities;
  (4) a description of the utility's efforts to ensure that costs of the facilities are reasonable and were prudently incurred; and
  (5) a description of the benefits of the project in promoting the development of renewable energy in a manner consistent with this chapter.

A. PROJECT ELIGIBILITY

In previous proceedings, the Commission found that MP's Bison Wind Projects and related transmission components qualified as eligible technologies under Minn. Stat. §216B.1691 and approved the related investments and expenditures.[7] As described below, MP divides each of its Bison projects into sub-parts for purposes of calculating its overall revenue requirement. The Department compared the list of project sub-parts in MP's Petition, Exhibit B-1, page 3 to the list of sub-parts approved in prior RRR Dockets (for Bisons 1, 2, and 3) and the sub-parts approved in Docket No. E015/M-13-907 (for Bison 4). All project sub-parts included in MP's petition were included in those prior Dockets. Therefore, the Department concludes that all of the projects for which MP is seeking recovery in its Petition are eligible for cost recovery.

B. TOTAL PROJECT COSTS AND COST CAPS

In Xcel's Transmission Cost Recovery Rider (TCR Rider) filing in Docket No. E002/M-09-1048, the Commission set the standard for evaluating rider project costs going forward. The Commission stated in its April 7, 2010 Order that:

> …the Commission finds that TCR project cost recovery through the rider should be limited to the amount of the initial cost estimates at the time the projects are approved as eligible projects, with the opportunity for the Company to seek recovery of excluded costs on a prospective basis in a subsequent rate case. A request to allow cost recovery for project costs above the amount of the initial estimate may be brought for Commission review only if unforeseen or extraordinary circumstances arise on a project.

Table 3 below summarizes the initial capital cost estimates from the initial eligibility filings of each of the Bison projects, and compares those estimates to the estimates presented in MP's prior RRR filing, and the instant RRR filing.

[7] See Docket Nos. E015/M-09-285 (Bison 1), E015/M-11-234 (Bison 2), E015/M-11-626 (Bison 3), and E015/M-13-907 (Bison 4).

Table 3:
Summary of Capital Expenditure Estimates
($ Millions)

	Capital Expenditures		
	Cost Eligibility Filings	**2013 RRR Filing**	**2014 RRR Filing**
	1/	2/	3/
Bison 1	177.6	172.7	173.2
Bison 2	157.0	144.6	147.7
Bison 3	157.0	146.3	148.7
Bison 4	339.7	n/a	340.9

1/ Cost Eligibility Filings:
Bison 1 - Docket No. E015/M-09-285
Bison 2 - Docket No. E015/M-11-234
Bison 3 - Docket No. E015/M-11-626
Bison 4 - Docket No. E015/M-13-907 - The Department notes that the capital expenditure figure for Bison 4 in the table is not in the official record in the Bison 4 cost eligibility Docket. The reported $339.7 million was taken from the financial model used to calculate the annual revenue requirements included in Attachment 2 to the Department's November 12, 2013 Comments in that Docket.
2/ Docket No. E015/M-13-410
3/ Petition, Exhibit B-3

As shown, the most recent capital expenditure estimates for Bisons 1, 2, and 3 are below the initial estimates from the projects' eligibility filings. The estimate of capital expenditures for Bison 4 in MP's Petition is $1.2 million, or 0.4 percent, above the estimate in its cost eligibility filing. Consistent with the Commission's decision in Docket No. E002/M-09-1048, the Department recommends that the Commission limit the Bison 4 costs included in MP's RRR to the $339.7 million contemplated in Docket No. E015/M-13-907.

The Department recalculated MP's 2014 revenue requirement with capital expenditures limited to $339.7 million by removing the last $1.2 million in capital expenditures from MP's revenue requirement calculations. As shown in Exhibit B-3 of MP's Petition, MP's 2014 revenue requirement calculation assumes capital expenditures of $26.1 million in December 2014. The Department reduced this figure to $24.9 to implement the cost cap, which reduced MP's 2014 revenue requirement by less than $10,000. This small change had no effect on the proposed RRR rates.

C. 2014 REVENUE REQUIREMENT

As noted above, MP divides each of its four Bison projects into sub-parts, and calculates a separate revenue requirement for each sub-part.[8] The revenue requirements of all sub-parts are summed to derive the total 2014 revenue requirement of $51.7 million. The Department discusses several aspects of the Company's revenue requirements calculations below.

1. AFUDC

As explained in MP's response to Information Request No. 4, MP accrues an allowance for funds used during construction (AFUDC) on investments and expenditures related to each project sub-part until the Commission approves cost recovery in a cost eligibility filing.[9] Thus, for investments and expenditures in Bison 4, MP accrued AFUDC on investments and expenditures made prior to January 17, 2014, when the Commission approved cost recovery for Bison 4 in Docket No. E015/M-13-907.

MP calculates monthly AFUDC rates, updated annually, based on the Company's capital structure and return on equity approved in its most recent rate case (Docket No. E015/GR-09-1151, or the 2009 Rate Case), as well as its actual cost of debt from the prior year.[10] MP's methodology (which was also used in the 2013 RRR Filing) is based on Federal Energy Regulatory Commission (FERC) methodology, and assumes that short-term debt is the first source of construction funding. If a company's construction work in process (CWIP) balance exceeds its outstanding short-term debt, FERC's methodology assumes that the remaining CWIP balance is funded by long-term debt and equity, proportional to the Company's long-term debt and equity balances. In its response to Information Request 2, MP stated that it does not have, and has not had, a short-term debt balance. Therefore its entire CWIP balance is funded by long-term debt and equity. Because MP has no short term debt, and its cost of long-term debt in 2013 was similar to the cost of long-term debt approved in the 2009 Rate Case, MP's annualized AFUDC rate is nearly equal to the cost of capital approved in the 2009 Rate Case. The Department notes that for companies with a short-term debt

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[8] See MP's Petition, Exhibit B-1, page 3 for a complete list of project sub-parts.
[9] See Department Attachment 2.
[10] See Attachment 4 to MP's response to Information Request No. 2, included with these Comments as Department Attachment 3. The Department notes that, as shown in Department Attachment 3, MP first calculates an AFUDC rate using its actual capital structure, actual cost of debt, and its most recent Commission-approved return on equity. MP then calculates a second AFUDC rate using the capital structure and return on equity approved in its most recent rate case, along, as well as its actual cost of debt from the prior year. MP then performs a third AFUDC calculation in which the overall AFUDC rate is set equal to the overall rate calculated in the second calculation. However, in this third calculation, the debt portion of the rate is set equal to the debt portion from the first AFUDC calculation, and the equity portion of the rate is then adjusted so that the debt and equity portions sum to the overall AFUDC rate from the second calculation.

balance, FERC's AFUDC methodology produces AFUDC rates which are lower than the companies' overall cost of capital.

Additionally, MP compounds its capitalized AFUDC semi-annually, which is consistent with FERC methodology.

After review, the Department concludes that MP's treatment of AFUDC is reasonable.

2. Return on CWIP

Once the Commission approves a project for cost recovery, MP ceases to accrue AFUDC and begins to earn a current return on CWIP, as permitted by Minn Stat. §216B.1645, subd. 2a(a)(2). MP calculates a full return on its CWIP balance at its cost of capital as determined in its most recent rate case. As explained above, this does not represent a material change from the Company's AFUDC rate as a result of the Company having no short-term debt. However, during this period, MP does not accrue the allowed return in CWIP, but rather recovers the allowed return via its renewable rider, and any unrecovered amounts will accrue in the tracker.

The Department concludes that MP's treatment of return on CWIP is reasonable.

3. Internal Capitalized Costs

The Commission's December 13, 2013 Order on MP's 2013 RRR Filing, required MP to exclude internal capitalized costs from its calculation of AFUDC and return on CWIP. In its Petition, MP excluded internal capitalized costs from its AFUDC and CWIP calculations, as shown in Exhibit B-3 to its Petition. The Department reviewed these calculations and concludes that they are reasonable.

4. Net Operating Losses and Deferred Tax Assets

In MP's most recently approved TCR rider filing, the Commission required the Company to use a hybrid approach when accounting for net operating losses (NOLs) and the deferred tax assets (DTAs) these NOLs create. The Commission required MP to include in rate base the smaller of the DTAs calculated using the stand-alone and consolidated methods.[11] Exhibit B-2 to MP's Petition contains the revenue requirement calculations for each project sub-part, and section E of each calculation applies the hybrid method as required. The Department reviewed MP's calculations and concludes that they are reasonable.

[11] See the Department's January 25, 2013 Comments in Docket No. E015/M-11-695 for a more detailed explanation of the stand-alone and consolidated methods.

5. Production Tax Credits and the North Dakota Investment Tax Credit

On page 16 of its Petition, MP stated that the production tax credits (PTCs) generated by the wind projects are credited as an offset to revenue requirements in the year they are generated. However, as a result of the Company's NOLs, the cash benefits of the PTCs will not be realized in the year generated, but rather will be deferred for future realization as DTAs.

Similarly, MP's Bison Wind projects qualify for the North Dakota Investment Tax Credit (ND ITC), but MP is unable to utilize this credit due to a lack of taxable income. MP stated on page 16 of its Petition that to the extent it generates taxable income in North Dakota in the future, any resulting income taxes will be offset by the use of this credit. The Company also stated that it will offset future RRR revenue requirements with the ND ITC once the credits have been realized.

The Department concludes that MP's treatment of PTCs and the ND ITC is reasonable.

D. TRACKER BALANCE

In addition to its revenue requirements, described above, MP is also requesting recovery of under-recovered amounts from prior years, which it accrues in a tracker. Exhibit B-1 of MP's Petition reports that its tracker balance increased by $18.0 million during 2013, from $16.1 million to $34.1 million. A portion of this increase is attributable to a timing difference between the time MP initially assumed the rates proposed in its 2013 RRR Filing would be implemented and the time the new rates were actually implemented. However, approximately $6.6 million of this increase is attributable to an increase in actual 2013 revenue requirements relative to the estimated 2013 revenue requirements. In its 2013 RRR Filing, MP estimated a 2013 revenue requirement of $28.6 million. In Exhibit B-1 of its Petition in this Docket, MP calculated an actual 2013 revenue requirement of $35.2 million. In its response to Department Information Request No. 5, MP attributed the difference between the estimated and actual 2013 revenue requirement to lower-than-expected production from the operating Bison projects, which resulted in significantly less PTCs to offset costs.[12]

The Department concludes that MP's tracker balance calculations are reasonable, but discusses the Bison projects' 2013 wind production further below.

F. COST ALLOCATION AND RATE DESIGN

MP's cost allocations and rate calculations are shown in Exhibit B-1 of its Petition.
As noted above, MP used its Power Supply Production and Power Supply Transmission demand allocators to allocate costs between the LP class and all other retail classes. This is

[12] See Department Attachment 4.

the same approach used in MP's prior RRR filings, and the Department continues to conclude that it is reasonable.

As described above, MP proposed to calculate demand and energy adders for its LP customer class, and to calculate a single average energy adder for all other retail classes. The proposed adder for all other retail classes is equal to the group's total revenue requirement (the sum of the group's allocated 2014 revenue requirement and its tracker balance) divided by MP's estimate of the group's 2014 energy consumption. MP proposes to split the LP customer class' total revenue requirement between demand and energy based on the approximate split used in MP's most recent rate case (60 percent demand, 40 percent energy). The demand and energy adders are then calculated using MP's 2014 estimated billing factors. This is the same approach approved in MP's last two RRR Dockets, and the Department continues to conclude that it is reasonable.

G. TARIFF SHEETS

The Department reviewed the Company's proposed tariff sheets for the RRR contained in Exhibit A-1 of MP's Petition. The only substantive change from MP's existing tariff sheets is the new proposed rates. The Department concludes that the proposed changes are reasonable.

H. LOW ENERGY PRODUCTION

1. Low 2013 Wind Speeds

As noted above, 2013 energy production at Bisons 1, 2, and 3 was significantly lower than expected. In its response to Information Request No. 5, MP stated that actual "generation 780,799 MWh was 260,480 MWh lower than in the 2013 budget." Table 4 below compares the level of expected energy production used in the cost eligibility filings of Bisons 1, 2, and 3 to actual 2013 production.

Table 4:
Estimated Energy Production Versus Actual at
Bisons 1, 2, and 3

Project	Estimated Annual Production from Cost Eligibility Filing (MWh)	Actual 2013 Production (MWh)	Difference (MWh)	Difference (%)
	1/	2/		
Bison 1	300,000			
Bison 2	380,000			
Bison 3	365,000			
Total	1,045,000	780,799	(264,201)	-25.3%

1/ Cost Eligibility Filings:
Bison 1 - Docket No. E015/M-09-285
Bison 2 - Docket No. E015/M-11-234
Bison 3 - Docket No. E015/M-11-626
2/ MP's response to Information Request No. 5 (See Department Attachment 4)

As shown, actual 2013 MWh production fell 25.3 percent short of the expected level of production used to demonstrate that these Bison projects were cost-effective in their respective eligibility filings. This low level of production raises concerns due in part to the immediate financial impact it has on MP's ratepayers described above (*i.e.,* fewer production tax credits, which results in larger tracker balance), and also in part to the longer-term financial implications if the production estimates used in projects' eligibility filings were inaccurate. A sustained level of energy production that is lower than initially expected will result in higher levelized cost of the energy produced by the projects.

In its response to Information Request No. 12, MP stated that the probability of experiencing energy production levels as low as or lower than actual production in 2013 due to wind variability can be estimated by comparing the average wind speed in 2013 with historical averages at the Bison site. MP estimated that the probability of experiencing wind speeds (as opposed to energy production) as low or lower than actual 2013 wind speeds is less than two percent.[13] Based on this estimate, it is reasonable to expect to see winds speeds at this level approximately once every 50 years. Thus, while 2013 does not appear to be a statistical impossibility, the fact that only one full calendar year of production data from

[13] See Department Attachment 5. This estimate assumes that average annual wind speeds are normally distributed.

Bisons 2 and 3 is available (which were placed in service on December 18, 2013), and the data for that one year is significantly different than expected, raises concerns.

The Department is satisfied with MP's response at this time, but notes that there are additional questions related to energy production at the Bison projects. For example, in its response to Information Request No. 12, MP used wind data from a 60-meter meteorological tower located at the Bison site. While this is a reasonable proxy for the purposes of responding the Department's Information Request, the Department notes that the turbines installed at the Bison projects have hub heights of either 80 or 92.5 meters, and it is not immediately clear to the Department that it is appropriate to infer wind speeds at one altitude from data gathered at a different altitude. Additionally, the Department notes that actual 2013 average wind speed (7.13 meters/second) was approximately 4.3 percent lower than the 21-year average (7.50 m/s). The Department is generally aware that the relationship between wind speed and energy production is not linear, but it is also not immediately clear that a reduction in wind speeds of 4.3 percent would result in a decrease in energy production of 25.3 percent.

The Department will continue to monitor energy production from the Company's Bison Wind projects in future RRR filings as well as other relevant Dockets.

I. RATEPAYER IMPACTS

Table 5 summarizes the proposed increase in total costs to be recovered via the RRR.

Table 5:
Increase in Costs
Flowing Through RRR

			Increase	
	2013	2014	($)	(%)
Revenue Requirement	28.6	51.7	23.1	81%
Tracker Balance	17.0	34.1	17.1	101%
Total	45.6	85.8	40.2	88%

As shown, the total costs have increased by nearly 90 percent, resulting in the large rate increases (over 100 percent for the LP class, and 79 percent for all other retail classes) shown in Table 2 above.

While the Department concludes that all of the costs MP has proposed to recover via its RRR are reasonable, the Department is concerned about the impact these large rate increases will have on ratepayers. Additionally, the Department notes that a large portion of this increase, the portion attributable to the tracker balance (which represents nearly 40 percent of total 2014 costs), is expected to be short-lived. In its response to Information Request No. 10, MP stated that considering only the projects approved by the Commission for inclusion in the RRR, the Company expects its tracker balance to grow to approximately $40 million by December of 2014.[14] Additionally, the Company stated that it expects to file another RRR petition in fall 2014, and expects its tracker balance to be “minimal” by December 2015. The Department notes that MP recently filed a Petition requesting approval to include in its RRR investments and expenditures for a restoration project at its Thomson Hydroelectric Development, which was damaged by record rainfall and flooding in 2012.[15] If the Commission were to approve MP’s request, the RRR tracker balance may persist past 2015. However, once the tracker balance is paid off, which is likely to happen in the next two or three years, a large portion of the total costs flowing through the RRR, will be eliminated, and rates will decrease nearly as quickly as they are currently increasing.

For this reason, the Commission may wish to consider ways to mitigate the proposed increase and smooth out some of the volatility expected in MP’s RRR rates over the next few years. One option would be to stretch recovery of the tracker balance over a period of two years. MP’s current rate design divides the full tracker balance over estimated 2014 billing determinants, and therefore implicitly aims to recover the full tracker balance over a period of twelve months (which is standard practice). The Commission could require MP to calculate its rates such that it aims to recover only half of its tracker balance ($17.1 million) over the next twelve months.

Table 6 demonstrates the impact stretching the recovery of the tracker balance over two years would have on MP’s RRR rates. The increases, while still substantial, would be mitigated significantly.

[14] See Department Attachment 6.
[15] Docket No. E015/M-14-577

**Table 6:
Effects of Stretching
Tracker Balance Recovery Over Two Years**

		Current	As Proposed		With 2-Yr. Stretch	
Class	Charge Type	RRR Rate	RRR Rate	Increase	RRR Rate	Increase
Large Power	Demand (¢/kW - month)	1.70	3.45	103%	2.85	68%
	Energy (¢/kWh)	0.163	0.329	102%	0.272	67%
All Other Retail Classes	Energy (¢/kWh)	0.614	1.102	79%	0.844	37%

Sources: Current and Proposed RRR Rates from Petition, Exhibit B-1, page 1 of 7
RRR Rate with 2-Yr. Stretch from Department Attachment 7.

The Department notes, however, that MP does not earn a return on its tracker balance, and thus could be seen to be financially harmed by a decision to stretch the recovery of its tracker balance. If the Commission does not stretch the recovery of the tracker balance, and approves the rates proposed in MP's Petition, the Department recommends that the Commission require MP to file a new RRR petition by the end of 2015, or make a compliance filing in this Docket demonstrating that the approved rates are still reasonable. Because the rates proposed in this Petition reflect a large tracker balance, the Department is concerned that if the tracker balance is paid off by the end of 2015 as currently projected, MP will begin to significantly over-recover costs from its ratepayers. In the event of a cost over-recovery, MP will not be required to pay any interest on the over-recovered balance, and thus ratepayers will be harmed. To be clear, the Department is not accusing MP of attempting to intentionally over-recover costs. Rather, the Department is trying to protect ratepayers from a possibility that may or may not come to fruition, but deserves consideration.

IV. CONCLUSION AND RECOMMENDATIONS

After review, the Department concludes that all of the costs for which MP requested recovery via its RRR are reasonable with the exception of the Bison 4 costs, which should be limited to the costs contemplated in Docket No. E015/M-13-907. Further, as described above, the Department is concerned about the impacts the large proposed rate increases may have on ratepayers. As shown in Table 2 above, MP has proposed to approximately double the rates charged to its LP customer class, and increase the rates charged to all other retail classes by nearly 80 percent. As shown in Table 5, these increases will result in an increase in revenue of $40.2 million on an annual basis. For this reason, the Department recommends that the Commission consider requiring the Company to stretch the recovery of its tracker balance over a period of two years. The Department notes that doing so will benefit ratepayers by mitigating the proposed rate increase and smoothing some of the volatility expected in MP's RRR rates over the next few years. However, the Department also notes that stretching recovery of the tracker balance may harm MP financially, as it does not earn a return on its tracker balance. If the Commission requires this, the Department recommends that the Commission require MP to make a compliance filing in this Docket with the new RRR rates and updated tariff sheets.

If the Commission approves MP's RRR rates as proposed, the Department recommends that the Commission require MP to file a new RRR petition by the end of 2015, or make a compliance filing in this Docket demonstrating that it RRR rates are still reasonable.

/lt

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: E015/M-14-349 Date of Request: June 9, 2014

Requested From: Lori Hoyum, Minnesota Power Response Due: June 19, 2014

Analyst Requesting Information: Craig Addonizio

Type of Inquiry:			
	[X]....Financial	[ ].....Rate of Return	[ ].....Rate Design
	[ ].....Engineering	[ ].....Forecasting	[ ].....Conservation
	[ ].....Cost of Service	[ ].....CIP	[ ].....Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.

3. Reference: Exhibit B-1, Page 2

Exhibit B-1, Page 2 reports 2012 Ending Tracker (Over)/Under Collection and 2013 Cash Collections by customer class. Please explain whether these amounts are directly tracked by customer class, or estimated in some way. If these amounts are estimated, please explain the methodology used and provide the calculations with all supporting data.

Response:

The 2012 Ending Tracker (Over)/Under Collection is directly tracked. The actual revenue requirements are allocated to customer class and then compared to the actual cash collection by class from Minnesota Power's Customer Information System ("CIS") to calculate the over/under collection. As with the 2012 cash collections, the 2013 cash collections are the actual cash collections by class from Minnesota Power's CIS.

Response by: Stewart Shimmin

Title: Supervisor, Revenue Requirements

Department: Rates

Telephone: (218) 355-3562

List sources of information:

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

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	[ ]......Cost of Service	[ ]......CIP	[ ]......Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.

4. Reference: Exhibit B-3, Pages 16-17

Exhibit B-3, pages 16-17 show several projects associated with Bison 4 accruing AFUDC through January 2014, and earning a current return on CWIP beginning in February 2014. Please explain why MP chose to begin calculating current return on CWIP beginning in February 2014, even though it anticipates rate recovery will not begin until August 2014.

Response:

Minnesota Power begins recording rider revenue the beginning of the month after Commission approval of a current cost recovery Plan filing or Certificate of Need (CON). The Company begins recording rider revenue on projects exempt from requiring a CON upon approval of a route permit. Additionally, the beginning of the month after the approval of the Plan, CON filing, or route permit by the Commission, Minnesota Power discontinues recording AFUDC on the projects and the Company begins earning a return on CWIP as part of rider revenue. Minnesota Power starts billing customers when the billing factor is approved.

Minnesota Power began recording rider revenue and discontinuance of recording AFUDC for the Bison 4 project in February of 2014. This treatment is a direct result of the approval of

Response by: Herbert Minke

Title: Director, Regulatory Affairs

Department: Regulatory Affairs

Telephone: (218) 355-3919

List sources of information:

cost recovery determination for the Bison 4 project by the Commission in its order dated January 17, 2014.

The anticipated rate recovery date of August 2014 as noted by the Department, assumes a Commission order approving this billing factor in July 2014 and is the date on which Minnesota Power anticipates collections would begin on the 2014 Renewable Resources Rider billing factor and credited against the revenue requirements that began accruing in February 2014.

Response by:	Herbert Minke	List sources of information:
Title:	Director, Regulatory Affairs	
Department:	Regulatory Affairs	
Telephone:	(218) 355-3919	

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: E015/M-14-349 Date of Request: June 9, 2014

Requested From: Lori Hoyum, Minnesota Power Response Due: June 19, 2014

Analyst Requesting Information: Craig Addonizio

Type of Inquiry:			
	[X]....Financial	[ ]....Rate of Return	[ ]....Rate Design
	[ ]....Engineering	[ ]....Forecasting	[ ]....Conservation
	[ ]....Cost of Service	[ ]....CIP	[ ]....Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.

2. Reference: Exhibits in Microsoft Excel Format

Please provide the following Exhibits as working Microsoft Excel files:

a. Exhibit B-1, pages 3 through 7;
   i. Please provide Exhibit B-1 as shown in MP's filing, and also provide the monthly billing units and effective renewable factors used to calculate 2013 cash collections and monthly tracker balances in 2013, separated by Large Power and All Other Rate Classes.

b. Exhibit B-2;

c. Exhibit B-3;
   i. Please provide Exhibit B-3 as shown in MP's filing, and also provide all data necessary to calculate the AFUDC and AFUDC on Internal Cost amounts shown, as well as the underlying AFUDC rates;

d. Exhibit B-4; and

e. Exhibit B-5.

Response by: Stewart Shimmin

Title: Supervisor, Revenue Requirements

Department: Rates

Telephone: (218) 355-3562

List sources of information:

Response:

a. - e.

Refer to DOC IR 002.1 Attachment.xlsx for the requested exhibits in Microsoft Excel format. Refer to DOC IR 002.2 Attachment.xlsx for an example of how AFUDC and AFUDC on Internal Costs are calculated for Bison 4 Tri-County Substation, as well as the underlying AFUDC debt and equity rates for 2010 to 2014. Please note for Bison 4 Wind that there was an adjusting entry in December 2013 to add AFUDC associated with costs that will be moved to Bison 4 Wind. To tie to the December 2013 AFUDC shown in Exhibit B-3 for Bison 4 Wind, $38,658.49 in AFUDC debt and $102,721.87 in AFUDC equity need to be added to the amounts calculated following the methodology shown in the example. Refer to DOC IR 002.3 Attachment.xlsx and DOC IR 002.4 Attachment.xlsx for the calculation of AFUDC rates for 2011 and 2013, respectively, as confirmed by email.

Response by:	Stewart Shimmin	List sources of information:
Title:	Supervisor, Revenue Requirements	
Department:	Rates	
Telephone:	(218) 355-3562	

CALCULATION OF DEBT RATE
YEAR 2013

Step 1. Calculate debt rate based on actual balances from prior year

	Actual Amounts as of 12/31/2012	Capitalization Ratio	Percentages	Cost Rates	Cost Rates for Net-of-Tax Rates	Monthly %
Short Term Debt 1/	0	0.00%				
Long-Term Debt End of Year	963,559,848	45.10%	45.10%	4.97%	2.24%	0.19%
Preferred Stock End of Year	0	0.00%	0.00%	0.00%	0.00%	
Common Equity 2/ End of Year	1,172,832,514	54.90%	**54.90%**	10.38% 1/	5.70%	0.47%
Total Capitalization	2,136,392,362	100.00%	100.00%		**7.94%**	0.66%

1/ As Minnesota Power does not have (and has not had) a short-term debt balance, it is not included in the AFDC calculation.
2/ Common EQUITY, not Common STOCK, which includes Retained Earnings
3/ Per FERC METHOD, cost rate for equity is the rate granted as of the last proceeding. The rate is not changed due to a new rate order until the following year. *FERC CFR 18, Pt. 101, Electric Plant Instructions 3A(17)*

CALCULATION OF ANNUAL AND MONTHLY AFUDC RATES
YEAR 2013

Step 2. Calculate total AFUDC rate based on FERC rules

	Actual Amounts as of 12/31/2012	Capitalization Ratio	Limited Percentages	Cost Rates	Weighted Cost Rates for Net-of-Tax Rates	Limited Rates 4/	Monthly %
	(000's Omitted)						
Long-Term Debt End of Year	963,559,848	45.10%	45.71% 3/	4.97%	2.27%	2.24% 2/	$\boxed{0.1868\%}$
Preferred Stock End of Year	0	0.00%	0.00%	0.00%	0.00%		
Common Equity 1/ End of Year	1,172,832,514	54.90%	**54.29%** 3/	10.38%	5.64%	5.67%	$\boxed{0.4721\%}$
Total Capitalization	2,136,392,362	100.00%	100.00%		**7.91%**	7.91%	0.6589%

1/ Common EQUITY, not Common STOCK, which includes Retained Earnings
2/ Debt rate MUST be equal to that calculated under FERC rules
3/ Cap structure allowed in last rate case
4/ Based on the January 7, 1977 Federal Power Commission (predecessor to the FERC) Docket RM 75-27, Order 561

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: E015/M-14-349 Date of Request: June 9, 2014

Requested From: Lori Hoyum, Minnesota Power Response Due: June 19, 2014

Analyst Requesting Information: Craig Addonizio

Type of Inquiry:	[X].....Financial	[ ].....Rate of Return	[ ].....Rate Design
	[ ].....Engineering	[ ].....Forecasting	[ ].....Conservation
	[ ].....Cost of Service	[ ].....CIP	[ ].....Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
5.	Reference: 2013 Revenue Requirements In Docket No. E015/M-13-410, MP estimated 2013 revenue requirement to be $28.6 million. In the instant Petition, MP reported actual 2013 revenue requirement of $35.2 million (Exhibit B-1, page 7), an increase of $6.6 million, or 23.1 percent. Please explain the reasons for the increase. **Response**: The 2013 total actual Bison 1-3 wind generation of 780,799 MWh was 260,480 MWh lower than in the 2013 budget. This resulted in almost $6 million less in production tax credits at $23/MWh. After grossing up, this increased total company revenue requirements by about $10.2 million. This increase was offset by a reduction in revenue requirements of about $2.2 million resulting from the combined impact of higher Stand-Alone Accumulated Deferred Income Tax Assets for net operating losses ("ADITA-NOL") in Bison 3 and lower Consolidated ADITA-NOL due to the overall limitation of Consolidated ADITA-NOL being placed on Bison 3. After applying the Minnesota jurisdictional allocation factors to the total net increase of about $8 million, the increase to retail classes is about $6.6 million above what was estimated in Docket No. E015/M-13-410.

Response by: Stewart Shimmin List sources of information:

Title: Supervisor, Revenue Requirements

Department: Rates

Telephone: (218) 355-3562

State of Minnesota

Department of Commerce
Division of Energy Resources

Utility Information Request

Docket Number: E015/M-14-349 | Date of Request: August 1, 2014

Requested From: Lori Hoyum, Minnesota Power | Response Due: August 13, 2014

Analyst Requesting Information: Craig Addonizio

Type of Inquiry:			
	[X]......Financial	[ ]......Rate of Return	[ ]......Rate Design
	[ ]......Engineering	[ ]......Forecasting	[ ]......Conservation
	[ ]......Cost of Service	[ ]......CIP	[ ]......Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
12	Reference: 2013 Wind Production a. Please provide copies of all wind studies used to support the eligibility filings for Bisons 1, 2 and 3. b. In the cost eligibility filings for each of the Bison wind projects, MP developed estimates of expected energy production and average wind speeds for each project. Did MP also develop estimates of the expected variability of average wind speeds (*e.g.*, standard deviations)? If so, please provide those estimates. c. Please use the estimates of expected average wind speeds and expected variability to estimate the probability of experiencing energy production levels as low or lower actual production in 2013.

Response by:	Barry Gartner	List sources of information:
Title:	Project Development Leader	2010 Bison 1 Wind Study
Department:	Strategy and Planning	2011 Bison 2 Wind Study
Telephone:	218-355-3333	2011 Bison 2 & 3 with Existing Bison 1 Wind Study

Response:

a. Attached are the wind studies used to support the long-term average energy estimates for the Bison 1, 2, and 3 wind projects. **[TRADE SECRET Attached Wind Studies]**

   The Bison 1 Cost Recovery Petition, dated 3/23/2009 (ref. Docket E015/M-09-285), identified the estimated annual energy production as 300,000 MWh/yr. This was based on the original design of (33) 2.3 MW turbines. As stated in the Bison 1 Wind Project original filing, Minnesota Power retained WindLogics in 2006 to assist with wind prospecting within 25 miles of Center, North Dakota. The estimated annual energy output of approximately 300,000MWh/yr was based on wind data provided by WindLogics, as well as data from the nearby Oliver I and Oliver II Wind Projects. The Company has not been able to locate the wind study data and would need to contact WindLogics to see if they retained a copy of the study. However, in a Compliance Filing, dated 10/29/2010, Minnesota Power reported that the Bison 1 design was changed to (16) 2.3 MW turbines and (15) 3.0 MW turbines. The design changed increased the capacity of the wind project without increasing the project's capital cost. Attachment DOC IR 012.1 is a wind study dated 9/22/2010 for the Bison 1 wind project with (16) 2.3 MW turbines and (15) 3.0 MW turbines. It estimated the long-term average annual energy production at 313,603.9 MWh.

   The Bison 2 Cost Recovery Petition, dated 3/24/2011 (ref. Docket No. E015/M-11-234), identified the estimated annual energy production as 380,000 MWh/yr. Attachment DOC IR 012.2 is a wind study dated 2/25/2011 for the Bison 2 wind project with (35) 3.0 MW turbines. It estimated the long-term average annual energy production at 380,796.9 MWh.

   The Bison 3 Cost Recovery Petition, dated 6/21/2011 (ref. Docket No. E015/M-11-626), identified the estimated annual energy production as 365,000 MWh/yr. Due to the close proximity of some of the Bison 2 and 3 wind turbines, it was necessary to calculate the incremental energy generated from adding the Bison 3 wind project. Attachment DOC IR 012.3 is the wind study dated 5/19/2011 for the Bison 2 and 3 wind projects with a total of (70) 3.0 MW wind turbines. It estimated the long-term average annual energy production of the Bison 2 and 3 wind projects at 745,587.7 MWh. The incremental energy from Bison 3 with (35) 3.0 MW turbines is the difference between the Attachment C and Attachment B energy estimates. Therefore the long-term average increase in annual energy production from adding the Bison 3 wind project was estimated at 364,790.8 MWh.

Response by:	Barry Gartner	List sources of information:
Title:	Project Development Leader	2010 Bison 1 Wind Study
Department:	Strategy and Planning	2011 Bison 2 Wind Study
Telephone:	218-355-3333	2011 Bison 2 & 3 with Existing Bison 1 Wind Study

b. Minnesota Power uses long-term average wind speeds based on historical data for developing estimates of expected average annual energy production for each project. The long-term average wind speed represents the P(50) value of the mean wind speed which has a probability of exceedance of 50%. That is, there is a 50% chance that in any given year the annual average wind speed will be less than the long-term average value, while there is also a 50% chance the average wind speed will be higher. Minnesota Power did not develop estimates of the expected variability of average annual wind speeds for the cost eligibility filings of the Bison wind projects.

c. The probability of experiencing energy production levels as low as or lower than the actual production in 2013 due to wind variability can be estimated by comparing the average wind speed in 2013 with the historical average wind speeds at the Bison site. For the purposes of this analysis, Bison meteorological tower no. 8646, with a height of 60 meters, was selected as the reference point in the wind speed comparison. The average annual wind speeds from 1993 thru 2013 at tower 8646 are provided in Figure 1. The average wind speed in 2013 was 7.18 m/s. The long-term average annual wind speed is 7.5 m/s, and represents the P(50) value. Assuming the average annual wind speeds over the last twenty years are normally distributed, then the probability of exceeding 2013's average wind speed is 98.25%. Conversely, the probability of experiencing an average annual wind speed as low as or lower than 2013's average wind speed is less than 2%.

Response by:	Barry Gartner	List sources of information:
Title:	Project Development Leader	2010 Bison 1 Wind Study
Department:	Strategy and Planning	2011 Bison 2 Wind Study
Telephone:	218-355-3333	2011 Bison 2 & 3 with Existing Bison 1 Wind Study

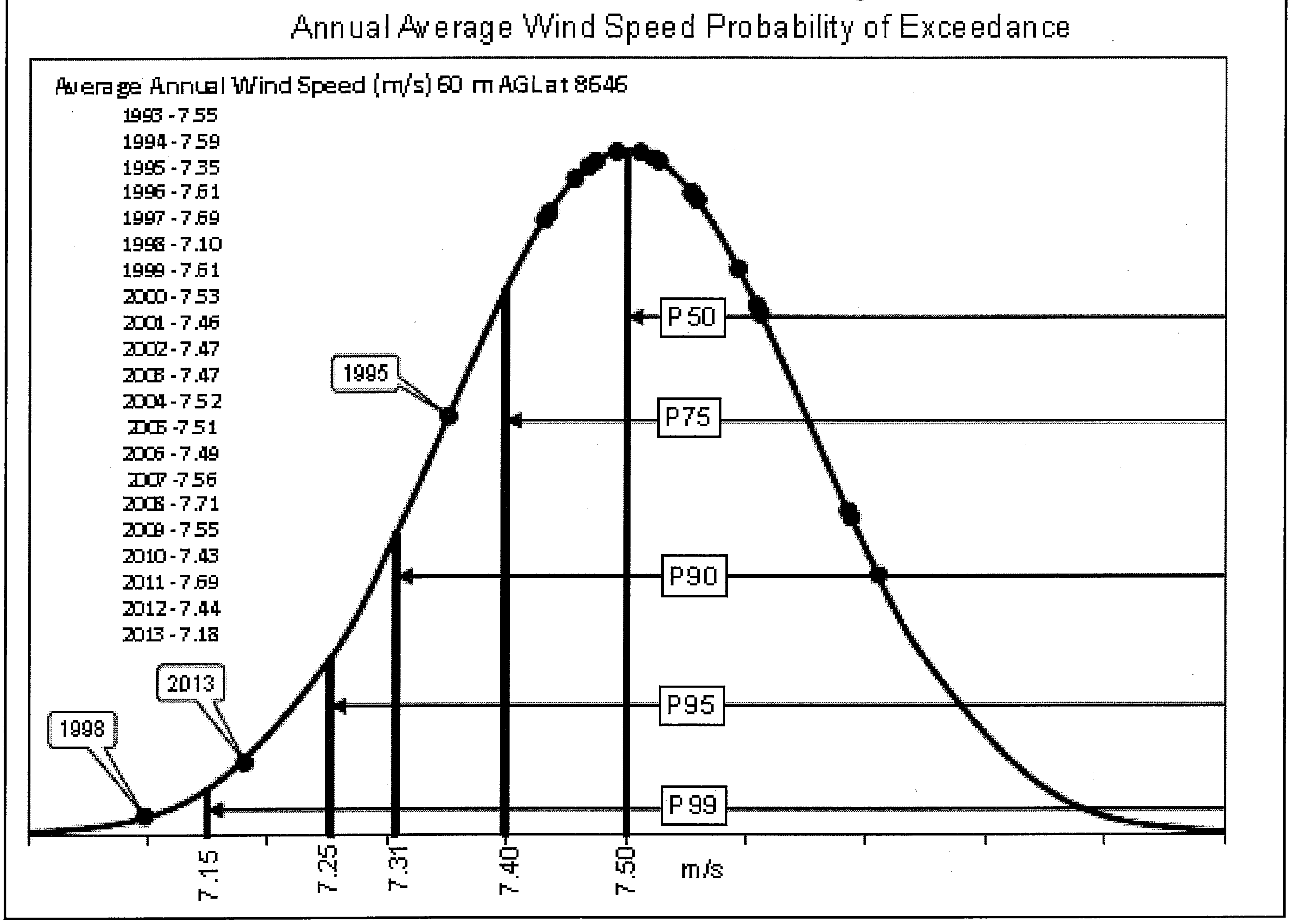

Figure 1: Probability of exceedance for annual average wind speeds (m/s) at Tower 8646.

Response by:	Barry Gartner	List sources of information:	
Title:	Project Development Leader	2010 Bison 1 Wind Study	
Department:	Strategy and Planning	2011 Bison 2 Wind Study	
Telephone:	218-355-3333	2011 Bison 2 & 3 with Existing Bison 1 Wind Study	

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: E015/M-14-349 Date of Request: June 9, 2014

Requested From: Lori Hoyum, Minnesota Power Response Due: June 19, 2014

Analyst Requesting Information: Craig Addonizio

Type of Inquiry:	[X]....Financial	[ ]......Rate of Return	[ ]......Rate Design
	[ ]......Engineering	[ ]......Forecasting	[ ]......Conservation
	[ ]......Cost of Service	[ ]......CIP	[ ]......Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.

10. Reference: Tracker Balance

The Department has a minor concern related to recovery of the $34 million tracker balance, which represents nearly 40 percent of the Total 2014 Factor Revenue Requirements. Specifically, the Department is concerned that the Renewable Factors set in this Docket will be designed to recover the entire tracker balance in 12 months. After that 12 month period is over, barring either a significant increase in costs that qualify for MP's renewable rider or a new rider filing, MP will begin significantly over-recovering its revenue requirements. Because MP does not earn interest on the tracker balance, it has a strong incentive update its Renewable Factors if it is under-recovering. However, the fact that MP *pays* no interest on *over*-recovered amounts gives it little or no incentive to update its Renewable Factors if it is over-recovering. Over-recovered amounts are essentially no-interest loans from MP's customers to the Company.

a. Please explain whether MP has given any consideration to the timing of its next renewable factor filing.

b. Please explain whether MP will complete any new projects in the next two years for which it expects to request cost recovery via its Renewable Resources Rider.

Response by: Herbert Minke

Title: Director, Regulatory Affairs

Department: Regulatory Affairs

Telephone: (218) 355-3919

List sources of information:

Response:

a. Minnesota Power has given significant consideration to when it projects to file its 2015 Renewable Resources Rider factor filing. It currently expects to file the 2015 filing in the fourth quarter of 2014.

b. Minnesota Power intends to file a cost recovery plan filing, requesting current cost recovery treatment from the Commission via its Renewable Resources Rider for the restoration of the Thomson Hydro facility that was taken out of service in the historic flooding of June 2012 .

Additional Comments:

The Company does not feel that questions nor the answers to a and b address the issues raised or inferred by the Department in this information request. Like the Department, Minnesota Power has a concern about the under-collected revenue requirements in its current cost recovery riders that results in a positive tracker balance. And, like the Department, Minnesota Power would also be concerned if it were over-recovering on any of its current cost recovery riders. But to state that the Company has no incentive to file for a billing factor update if it were over recovering is inaccurate.

For the Department of Commerce to infer that Minnesota Power is currently, or has the intent to prospectively, over-recover on any of its current cost recover riders is erroneous, not consistent with the facts in evidence in this and other current cost recovery dockets, and is inconsistent with the procedural commitments Minnesota Power has made in the various plan and factor filings when seeking current cost recovery treatment for these investments.

If the Department reviewed the tracker filings in any of Minnesota Power's previous Conservation Improvement Program, Transmission, Emission Reduction or Renewable Resources filings over the years it could easily determine that Minnesota Power has continually under-recovered on current cost recovery riders on an annual basis, consistently running positive tracker balances for which the company does not earn a rate of return.

The projected revenue requirements over the lives of each of the wind projects approved by the Commission for cost recovery and included in this filing illustrate the revenue requirements of an individual project drop significantly after the construction period when the facility is placed in service and the ten years that the production tax credit is generated. The 5 year accelerated tax depreciation also quickly reduces the rate base of the projects.

Response by:	Herbert Minke	List sources of information:
Title:	Director, Regulatory Affairs	
Department:	Regulatory Affairs	
Telephone:	(218) 355-3919	

See the Bison 4 Wind Project ("Bison 4") projected revenue requirements in Docket No. E015/M-13-907, Petition dated September 27, 2013, page 38 figure 10 for an illustration. With the four Bison wind projects staggered over the period 1/2012 through the projected in service date of Bison 4 in December of 2014, the billing factor rate has been effectively smoothed with the aggregation of the four projects.

Currently, considering only the projects approved by the Commission for inclusion in the Renewable Resources Rider ("RRR"), and with timely approval of this filing, the tracker balance for this rider will continue to grow to approximately $40 million by December of 2014. With a projected fall 2014 filing of the 2015 RRR billing factor, and assuming timely approval of the 2015 RRR billing factor, the projected tracker balance by December 2015 should be minimal. After the under-collected tracker balance is reduced the result is that the projected revenue requirements under this rider and the resulting billing factor amounts are expected to decline. To be clear, Minnesota Power is not asking for current collection in 2014 of the projected year-end 2014 under-collection in the tracker balance, but will request recovery in the subsequent 2015 RRR billing factor filing for the December 2014 amounts.

Response by:	Herbert Minke	List sources of information:
Title:	Director, Regulatory Affairs	
Department:	Regulatory Affairs	
Telephone:	(218) 355-3919	

Calculation of RRR Rates with
Tracker Balance Recovery Stretched Over Two Years

	As Proposed		Tracker Balance Over Two Years
2013 Tracker Balance ($)			
MN	34,121,430	x 50% =	17,060,715
LP	16,995,579	x 50% =	8,497,790
All Other Retail Classes	17,125,851	x 50% =	8,562,926
2014 Revenue Requirements ($)			
MN	51,677,295		51,677,295
LP	32,303,586		32,303,586
All Other Retail Classes	19,373,709		19,373,709
2014 Total Costs ($)			
MN	85,798,725		68,738,010
LP - Demand (60% of Total Costs)	29,579,499		24,480,825
LP - Energy (40% of Total Costs)	19,719,666		16,320,550
LP Total Costs	49,299,165		40,801,376
All Other Retail Classes	36,499,560		27,936,635
Billing Determinants			
LP kW-month	715,217		715,217
LP kWh	5,998,692,000		5,998,692,000
All Other Retail Classes kWh	3,310,820,000		3,310,820,000
LP Demand Adder (cents/kW-month)	3.45		2.85
LP Energy Adder (cents/kWh)	0.329		0.272
All Other Retail Classes Energy Adder (cents/kWh)	1.102		0.844

Source: Petition, Exhibit B-1

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Comments

Docket No. **E015/M-14-349**

Dated this 3rd day of September 2014

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_14-349_M-14-349
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	Yes	OFF_SL_14-349_M-14-349
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_14-349_M-14-349
Elizabeth	Goodpaster	bgoodpaster@mncenter.org	MN Center for Environmental Advocacy	Suite 206 26 East Exchange Street St. Paul, MN 551011667	Electronic Service	No	OFF_SL_14-349_M-14-349
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Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_14-349_M-14-349
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_14-349_M-14-349

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Herbert	Minke	hminke@allete.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_14-349_M-14-349
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Thomas	Scharff	thomas.scharff@newpagecorp.com	New Page Corporation	P.O. Box 8050 610 High Street Wisconsin Rapids, WI 544958050	Electronic Service	No	OFF_SL_14-349_M-14-349
Ron	Spangler, Jr.	rlspangler@otpco.com	Otter Tail Power Company	215 So. Cascade St. PO Box 496 Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_14-349_M-14-349
Eric	Swanson	eswanson@winthrop.com	Winthrop Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_14-349_M-14-349
Karen	Turnboom	karen.turnboom@newpagecorp.com	NewPage Corporation	100 Central Avenue Duluth, MN 55807	Electronic Service	No	OFF_SL_14-349_M-14-349