MINNESOTA DEPARTMENT OF COMMERCE

85 7TH PLACE EAST, SUITE 500
SAINT PAUL, MINNESOTA 55101-2198
MN.GOV/COMMERCE
651.539.1500 FAX: 651.539.1547
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March 11, 2015

Daniel P. Wolf
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-14-962

Dear Mr. Wolf:

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 2015 Renewable Factor.

The Petition was filed on November 10, 2014 by:

Susan Ludwig
Policy Manager
Minnesota Power
30 West Superior Street
Duluth, MN 55802

The Department expects to recommend **approval, with modifications, but first requests that Minnesota Power (MP) provide additional information in reply comments.** The Department will offer additional comments and recommendations in subsequent response comments after it reviews MP's reply comments.

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-14-962

I. INTRODUCTION AND BACKGROUND

On November 10, 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 E015/M-13-410 (the 2013 RRR Docket). MP also filed a petition for approval of a 2014 Renewal Factor in Docket No. E015/M-14-349 (the 2014 RRR Docket), which is currently pending before the Commission.

In its Petition, MP requests approval to recover the costs associated with Bisons 1, 2, 3, and 4 (the Bison Projects). Additionally, the Commission's March 5, 2015 *Order Finding Costs Eligible for Rider Recovery* in Docket No. E015/M-14-577 (the Thomson Cost Eligibility Docket) determined that the Company would be permitted to amend its Petition to propose recovery of the Thomson Restoration Project costs.

On February 13, 2015, MP filed a supplement to its Petition (Supplement) amending its proposal to include recovery of the Thomson Project Costs.

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

II. DETAILS OF MP'S PROPOSAL

A. REVENUE REQUIREMENT AND TRACKER BALANCE

MP requests recovery of its estimated 2015 revenue requirements for its Bison Projects and the Thomson Project, as well as recovery of under-collected amounts in the past, which MP accumulates in a tracker.

MP proposes to allocate a portion of its total company costs to the Minnesota jurisdiction using the allocators from its last rate case, Docket No. E015/GR-09-1151.[2] Table 1 below summarizes the total Minnesota-jurisdictional amount for which the Company requests recovery in its Petition.

**Table 1: Summary of
Estimated Total 2015 Revenue Requirement
($ Millions)**

2015 Revenue Requirement	
Bisons 1-4	45.3
Thomson	10.2
Subtotal	55.5
Tracker Balance	43.5
Total 2015 Revenue Requirement	99.0

Source: Supplement, Exhibit B-1, Page 1

Consistent with past RRR filings, 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 total 2015 revenue requirement ($99.0 million) between the two groups using its Power Supply Production and Power Supply Transmission demand allocators from its most recent rate case.[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 2014 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 2015 revenue requirements). The Company then calculates the difference between each group's allocated 2014 revenue requirement and its actual 2014 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.

[2] See Petition, page 16.
[3] See Petition, page 16.
[4] See Petition, Exhibit B-1, page 2 of 7.

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 using projected 2015 billing determinants. 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 adders are calculated using MP's 2015 estimated billing factors. [5]

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

Table 2: Summary of Current and Proposed RRR Rates

	RRR Rates			Increase from:	
	Current	2014 Proposed	2015 Proposed	Current	2014 Proposed
Large Power					
Demand (cents/kW - month)	1.700	3.45	4.26	150%	23%
Energy (cents/kWh)	0.163	0.329	0.404	148%	23%
All Other Retail Classes					
Energy (cents/kWh)	0.614	1.102	1.172	91%	6%

Source: Supplement, Exhibit B-1

III. MINNESOTA DEPARTMENT OF COMMERCE (DEPARTMENT OR DOC) 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

[5] See Supplement, Exhibit B-1.

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 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 Projects, the Thomson Project and related transmission components qualified as eligible technologies under Minn. Stat. §216B.1691 and approved the related investments and expenditures.[6] As described below, MP divides its Bison and Thomson 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 Bison-related sub-parts for which MP is seeking recovery in its Petition are eligible for cost recovery.

With respect to the Thomson Project, MP relied on the cost estimates it developed in the Thomson Project's Cost Eligibility Docket as the basis for its proposed level of cost recovery in its Supplement.[7] Because MP updated neither the revenue requirement of each individual sub-part associated with the Thomson Project nor complete list of sub-parts from the Cost Eligibility Docket to the instant Docket, the Department concludes that all of the Thomson-related sub-parts 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 cost estimates from the initial eligibility filings of each of the projects, and compares them to the cost estimates used to calculate revenue requirements in MP's prior RRR filing, and the instant RRR filing.

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[6] See Docket Nos. E015/M-09-285 (Bison 1), E015/M-11-234 (Bison 2), E015/M-11-626 (Bison 3), E015/M-13-907 (Bison 4), and E015/M-14-577 (Thomson Project).
[7] See Supplement, Exhibit B-1, footnote 2.

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

	Cost Eligibility Filings	2014 RRR Filing	2015 RRR Filing	Difference
	[1]	[2]	[3]	[4]=[1]-[3]
Bison 1	177.6	171.6	171.8	5.8
Bison 2	157.0	145.9	146.0	11.0
Bison 3	157.0	147.5	147.4	9.6
Bison 4	337.7	337.9	339.0	(1.3)
Thomson	84.1	n/a	84.1	0.0

[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 $337.7 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.
Thomson - DOC's Nov. 17, 2014 Comments in Thomson Project Cost Eligibility Docket, Attachment C, page 81
[2] MP's Petition in 2014 RRR Docket, Exhibit B-3
[3] Bisons 1-4 - Petition, Exhibit B-3
Thomson - DOC's Nov. 17, 2014 Comments in Thomson Project Cost Eligibility Docket, Attachment C, page 81

The Department notes that the estimates shown in Table 3 include capital expenditures and allowance for funds used during construction (AFUDC), and exclude internal costs and AFUDC on internal costs. Additionally, the Department notes that the cost caps reported for Bisons 1-3 are the cost caps used by the Commission and the Department in MP's prior RRR dockets, whereas the cost caps reported for Bison 4 and the Thomson Project are taken from the revenue requirements models in the cost eligibility Dockets for those projects (Docket Nos. E015/M-13-907 and E015/M-14-577).[8] As shown, the cost estimates for Bisons 1, 2, and 3 are below the initial estimates from the projects' eligibility filings. And because MP used the same revenue requirements calculation for the Thomson project in

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[8] See the 2014 RRR Docket for a more detailed discussion of the appropriate calculation of cost caps.

both its cost eligibility Docket and in the instant Docket, there is no difference between the two Dockets. However, the estimate of capital expenditures for Bison 4 in MP's Petition is $1.3 million 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 $337.7 million contemplated in Docket No. E015/M-13-907.

C. 2015 REVENUE REQUIREMENT

As noted above, MP divides each of its four Bison Projects and the Thomson Project into sub-parts, and calculates a separate revenue requirement for each sub-part. The revenue requirements of all sub-parts are summed to derive the total 2015 revenue requirement of $55.5 million. The Department discusses several aspects of the Company's revenue requirements calculations below.

Additionally, the Department notes that the revenue requirements calculations for the four Bison Projects are contained in Exhibits to MP's Petition, and the revenue requirements calculations for the Thomson Project are contained in Attachment C to the Department's November 17, 2014 Comments in the Thomson Cost Eligibility Docket.

1. AFUDC and Return on Construction Work in Process (CWIP)

Generally, 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. 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.

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. As shown in MP's revenue requirement calculations, the Company appropriately excluded internal capitalized costs from its AFUDC and return on CWIP calculations.

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

2. Production Tax Credits, Net Operating Losses, and Deferred Tax Assets

On page 15 of its Petition, MP stated that the production tax credits (PTCs) generated by the Bison Projects are credited as an offset to revenue requirements in the year they are generated. However, as a result of the Company's net operating losses (NOL), the cash benefits of the PTCs will not be realized in the year generated, but rather will be deferred for future realization as deferred tax assets (DTA).

In its November 12, 2013 Order in Docket No. E015/M-11-695, the Commission required the Company to use a hybrid approach when accounting for NOLs and the 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.[9] MP's revenue requirement calculations apply the hybrid method as required, and thus the Department concludes that MP's treatment of NOLs is reasonable.

3. North Dakota Investment Tax Credit

MP's Bison Projects qualify for the North Dakota Investment Tax Credit (ND ITC), but MP is currently unable to utilize this credit due to a lack of taxable income. MP stated on page 15 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.

As explained in the Department's December 17, 2014 Response Comments in the 2014 RRR Docket (2014 Response Comments), MP expects to generate approximately $113 million of North Dakota Investment Tax Credits (ND ITCs) pursuant to the Bison Projects. However, due to a lack of North Dakota taxable income, MP will be able to consume only a small portion, approximately $10.7 million, of those ND ITCs, which will be credited to ratepayers via the RRR. The Department's understanding of the Company's treatment of ND ITCs is that MP plans to consume the amount of ND ITCs necessary to reduce MP's North Dakota taxable income to zero, credit MP's ratepayers for those tax savings, and then give all remaining ND ITCs to MP's parent entity (ALLETE, Inc., or ALLETE) to use for the benefit of shareholders. In total, MP expects that $10.3 million of ND ITCs will be used for the benefit of ratepayers, and $11.3 million will be used for the benefit of shareholders, for a total of approximately $22 million. The remaining $91 million are expected to expire unused. The Department considers this proposed treatment to be unreasonable.

As also explained in the Department's 2014 Response Comments, all of the ND ITCs available to MP and ALLETE are the result of MP's investments in the Bison Projects, which are funded largely by MP's retail ratepayers. Therefore, the consumption of ND ITCs by affiliates of MP would represent a subsidization of ALLETE's non-regulated operations by its regulated operations, for which ratepayers would receive no compensation. ALLETE's non-regulated operations would enjoy a tax benefit which they played no role in creating and for which they are not responsible. Because MP's ratepayers are funding the capital investments which are generating the ND ITCs that MP's affiliates will consume (for the benefit of shareholders), the Department recommends that the Commission require MP to credit to revenue requirements all ND ITC tax credits used in ALLETE's consolidated North Dakota tax returns.

[9] 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.

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 $9.4 million during 2013, from $34.1 million to $43.5 million.

Additionally, the Department notes that MP's proposed tracker balance includes no costs associated with the Thomson Project. In the Thomson Cost Eligibility Docket, MP asked the Commission to grant eligibility of costs related to the project as of November 13, 2014, the project's in-service date.[10] In response, the Department stated that such a determination would be inconsistent with Commission determinations in past dockets.[11] The Department noted that for projects that are under construction at the time the Commission's cost eligibility Order is issued, the date of the Commission's Order has been used to determine when cost recovery can begin.[12] For projects that are already in-service, January 1st of the most recent year for which renewable rider rates have not already been determined has been used as the start date for cost recovery. In its Supplement, MP changed its requested cost recovery start date for the Thomson Project to January 1, 2015, and thus included no Thomson Project costs in the calculation of the tracker balance.

After review, the Department concludes that MP's requested cost recovery start date for the Thomson project and the Company's tracker balance calculations are reasonable.

F. COST ALLOCATION

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 the same approach used in MP's prior RRR filings. However, the Commission may wish to require the Company to update its retail allocators, as discussed below.

On November 5, 2013 in Docket No. E015/M-12-920, the Commission issued its *Order Approving Boswell Energy Center Unit 4 Retrofit Project and Authorizing Rider Recovery* (12-920 Order) approving a rider recovery mechanism (the BEC4 Rider) for costs associated with the Company's Boswell Energy Center Unit 4 Emissions Reduction Plan (the BEC4 Project). The 12-920 Order included a requirement that MP adjust retail allocation factors used in the rider if the load of its large power or wholesale customers changed. Specifically, at page 7 of the 12-920 Order, the Commission stated the following:

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[10] See MP's November 24, 2014 Reply Comments in the Thomson Cost Eligibility Docket.
[11] See the Department's December 12, 2014 Supplemental Comments in the Thomson Cost Eligibility Docket.
[12] See, for example, Docket No. E015/M-13-907.

> Finally, the Commission will require Minnesota Power to make annual rate factor adjustment filings, including adjusted retail allocation factors **if any large power or wholesale customer's load changes by 10 megawatts or more**, as agreed to by the parties [emphasis added].

The Department notes that the Ordering Point 5 of the Commission's October 26, 2007 *Order Approving MP's Boswell 3 Plan and Rider with Modifications* in Docket No. E015/M-06-1501 imposed a similar requirement on MP. While not required by the Commission's Order in Docket No. E015/M-07-216 (which established MP's RRR), the Department concludes that it is appropriate to use the same retail allocation factors across MP's various riders. Thus, the Department recommends that the Commission require MP to make a new RRR filing with updated allocators and rates if and when it updates its allocators in the BEC4 Rider.

On November 26, 2014, MP filed a Petition in Docket No. E015/M-14-990 (Docket 14-990) seeking approval of its proposed rates for the Emission Reductions Rider associated with the BEC4 Project. In that Petition, MP stated that in 2014 it lost a firm wholesale customer with an average 2013 load of approximately 19 MW. Despite this change, the Company did not propose to adjust its allocators in response. MP also stated that it expects to add a new retail Large Power customer with a demand of approximately 20 MW in 2015, and expected to propose adjusted allocators in its 2016 BEC4 rider filing as a result.[13]

In its February 25, 2015 Comments in Docket 14-990, the Department noted that the Commission's *12-920 Order* clearly set the threshold for triggering the retail allocation adjustments filings at 10 MW, and thus, it is unclear why MP did not comply with the Commission's *12-920 Order* in this regard when it states that it lost "firm Wholesale customer with an average 2013 load of approximately 19 MW" in 2014. The Department requested that MP, in its reply comments, provide additional information on the loss of the wholesale customer in 2014 and adjust the retail allocation factors and proposed rates in Docket 14-990.[14] The Department notes that MP's Reply Comments in that Docket are currently due March 16, 2015.

The Department requests that MP provide the same information in this Docket.

G. RATE DESIGN

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 2015 revenue requirement and its tracker balance) divided by MP's estimate of the group's 2015 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

[13] See MP's Petition in Docket 14-990 at pages 15-16.
[14] See the Department's February 25, 2015 Comments in Docket 14-990 at pages 11-12.

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.

H. 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 generally reasonable, but may need to be updated to reflect the Commission's final order to the extent it differs from MP's proposal as a result of limiting recovery of Bison 4 costs or updating retail allocators.

I. ENERGY PRODUCTION AT THE BISON PROJECTS

In its Comments in the 2014 RRR Docket, the Department noted that 2013 energy production at Bisons 1, 2, and 3 was approximately 25 percent lower than expected level of production used to demonstrate that these projects were cost-effective in their respective eligibility filings.[15] 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 a 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.

The Department did not recommend that the Commission take any action at the time, but committed to continue to monitor energy production from the Company's Bison Projects in future RRR filings as well as other relevant Dockets.

In response to Department Information Request No. 9 in the instant Docket, MP provided actual production at Bisons 1, 2, and 3 for the first eleven months of 2014. The Department annualized actual production for the first eleven months of 2014, and compared that annualized figure to the production estimates used in the projects' cost eligibility filings.

[15] See the Department's September 3, 2014 Comments in the 2014 RRR Docket at pages 10-13.

Table 4: Summary of Estimated and Actual Production at Bisons 1, 2, and 3

Project	Estimated Annual Production from Cost Eligibility Filing (MWh)	Actual Production Jan-Nov 2014 (MWh)	Actual Production Jan-Nov 2014 Annualized (MWh)	Difference (MWh)	Difference (%)
	[1]	[2]	[3]=[2] x (12/11)	[4]	[5]
Bison 1	300,000	252,682	275,653		
Bison 2	380,000	305,934	333,746		
Bison 3	365,000	307,949	335,944		
Total	1,045,000	866,565	945,344	(99,656)	-9.5%

[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. 9 (See Department Attachment 1)
[3] Annualization assumes production in December will be equal to average monthly production from January through November.
[4] = [3] - [1]
[5] = [4] / [1]

As shown in Table 4 above, the Department's estimate of the projects' 2014 production is approximately 9.5 percent below the initial production estimates from the projects' cost eligibility filings. While still low, 2014 energy production was much closer to initial estimates. The Department will continue to monitor this issue in future RRR dockets.

J. 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	2015	2014 to 2015	2013 to 2015
Revenue Requirement	28.6	51.7	55.5	7%	94%
Tracker Balance	17.0	34.1	43.5	27%	156%
Total	45.6	85.8	99.0	15%	117%

Source: MP RRR Petitions

As shown, both the annual revenue requirement and the tracker balance have increased significantly since 2013. These cost increases result in the RRR rate increases presented in Table 2 above. Table 6 summarizes the estimated bill impacts of these increases.

Table 6: Estimated Bill Impacts

	Bill Impact of:			
	2014 Proposed RRR Rate		2015 Proposed RRR Rate	
Class	($/mo.)	(%)	($/mo.)	(%)
Residential	3.96	4.86%	(0.39)	-0.46%
General Service	13.54	4.87%	1.34	-0.46%
Large Light & Power	1,112.26	6.02%	(109.42)	-0.56%
Large Power	230,935	7.27%	42,553	1.37%
Municipal Pumping	59.17	5.32%	(5.18)	-0.50%
Lighting	0.71	3.12%	(0.18)	-0.30%

Sources: 2014 data MP's Petition in 2014 RRR Docket, Table 1
2015 data from Petition, Table 1

As shown in Table 6, the proposed 2014 RRR rates, if and when implemented, will result in significant increases in monthly bills. The proposed 2015 RRR rates, when implemented, will provide only modest relief for the non-large power classes, and an approximately 1.4 percent increase for large power customers.

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 approximately 45 percent of total 2015 costs proposed for recovery) is expected to be short-lived, as MP's proposed rates are intended to recover the full tracker balance in a period of 12 months. The Department understands that the tracker balance has continued to grow since MP filed its Petition, however, assuming the proposed 2015 RRR rates take effect by July 1, 2015, roughly half of the tracker balance will be recovered in 2015. The remaining balance will be recovered in 2016, and it is possible that the tracker balance could be eliminated, or close to it, by the beginning of 2017.

Additionally, the Department notes that, separate from the tracker balance, annual revenue requirements are expected to decrease as well.

Table 7: Revenue Requirements for Renewable Projects 2014-2017 ($ Millions)

	2014	2015	2016	2017
Bisons 1-4	52.9	45.3	35.3	30.2
Thomson	-	10.2	10.8	10.6
Total	52.9	55.5	46.1	40.8

Sources:
2014 and 2015: Petition, Exhibit B-1
2016 and 2017: Department Attachment 2

As a result of the elimination of the tracker balance and the projected decrease in annual revenue requirements, it is possible that the total annual costs recovered through the RRR in 2017 ($40.8 million) will be less than half of the total costs in 2015 ($99.0 million). 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.

Table 7 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.

Table 8: Effects of Stretching Tracker Balance Recovery Over Two Years[16]

		Current	As Proposed		With 2-Yr. Stretch	
			2015		2015	
Class	Charge Type	RRR Rate	RRR Rate	Increase	RRR Rate	Increase
Large Power	Demand (¢/kW - month)	1.70	4.26	151%	3.35	97%
	Energy (¢/kWh)	0.16	0.404	148%	0.319	96%
All Other Retail Classes	Energy (¢/kWh)	0.614	1.172	91%	0.889	45%

Sources: Current RRR Rates: MP's Petition in the 2014 RRR Docket, Exhibit B-1
RRR Rate with 2-Yr. Stretch: Department Attachment 3.

The Department notes, however, that MP does not earn a return on its tracker balance, and none of the rates presented in Table 8 above includes any type of return on the Company's tracker balance. MP could be seen to be financially harmed by a decision to stretch the recovery of its tracker balance, as the Company would incur additional financing charges.

The Department suggested extending the tracker balance recovery period in its September 3, 2014 Comments in the 2014 RRR Docket. In its September 16, 2014 Reply Comments in the same Docket, MP requested that it be allowed to earn its full rate of return on the tracker balance to offset the additional financing costs associated with delayed recovery if the Commission agreed with the Department's suggestion. The Department, in its December 17, 2014 Response Comments, provided a discussion of the consequences of allowing various levels of return on the tracker balance, including no return, full return, and a return based on the Company's short-term cost of debt. In that discussion, the Department concluded that if the Commission determines that no return or a return based on MP's short-term cost of debt is appropriate, then MP's customers would benefit from extending the tracker balance recovery period to two years. If however, the Commission determines that the fair rate of return is MP's full cost of capital, then the Commission should not extend the recovery period, as the financing charges ratepayers would incur would be too high.

If the Commission does not extend 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 and will not result in an overrecovery during 2016.

[16] The Department notes that the rates presented in Table 8 are the rates proposed by MP and reflect neither the Department's recommended cost disallowances for Bison 4 nor any potential changes to the retail allocators. However, the Department expects that the impact of any such changes will be small, and the rates presented are generally representative.

IV. CONCLUSION

The Department requests that MP provide the information requested above relating to the need to adjust the Company's retail allocators. Upon review of MP's reply comments, the Department will make a final set of recommendations to the Commission.

Preliminarily, the Department recommends that the Commission:

- limit the Bison 4 costs included in MP's RRR to the $337.7 million contemplated in Docket No. E015/M-13-907;
- require MP to credit to revenue requirements all ND ITC tax credits used in ALLETE's consolidated North Dakota tax returns, not just the credits consumed by MP on a stand-alone basis; and
- require MP to make a new RRR filing with updated allocators and rates if and when it updates its allocators in the BEC4 Rider.

/lt

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: E015/M-14-962 | Date of Request: December 9, 2014

Requested From: Susan Ludwig, Minnesota Power | Response Due: December 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.	
9	Reference: Actual Generation at Bisons 1-3 Please provide actual, year-to-date MWh generation at Bisons 1, 2 and 3.

Response:

For the period from January 1, 2014, through November 30, 2014, the Bison 1, 2, and 3 Wind Projects produced a total of 866,565 MWhs, as detailed below.

a. Bison 1 produced 252,682 MWh.
b. Bison 2 produced 305,934 MWh.
c. Bison 3 produced 307,949 MWh.

Response by: Barry Gartner | List sources of information:

Title: Renewable Project Development Leader

Department: Strategy and Planning

Telephone: 218-355-3333

State of Minnesota

DEPARTMENT OF COMMERCE
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[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: Future Revenue Requirements To the extent available, please provide MP's estimates of the 2016 and 2017 revenue requirements MP expects to flow its Renewable Resources Rider. If possible, please provide separate estimates including and excluding MP's investments and expenditures in the Thomson Project (Docket No. E015/M-14-577).

Response

Minnesota Power estimates $35.3 million and $30.2 million in annual revenue requirements for the Bison Projects (Bison 1-4) will flow through the Renewable Resources Rider for 2016 and 2017, respectively. Assuming the Thomson Project is approved by the Minnesota Public Utilities Commission in early January, Minnesota Power estimates $10.2 million, $10.8 million and $10.6 million in annual revenue requirements for the Thomson Project will flow through the Renewable Resources Rider for 2015, 2016 and 2017, respectively.

Response by: Stewart Shimmin

Title: Supervisor, Revenue Requirements

Department: Rates

Telephone: (218)355-3562

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

	As Proposed		Tracker Balance Over Two Years
2014 Tracker Balance ($)			
MN Jurisdiction	43,484,615	x 50% =	21,742,308
Large Power	26,279,506	x 50% =	13,139,753
All Other Retail Classes	17,205,109	x 50% =	8,602,555
2015 Revenue Requirements ($)			
MN Jurisdiction	55,543,559		55,543,559
Large Power	34,720,396		34,720,396
All Other Retail Classes	20,823,163		20,823,163
2015 Total Costs ($)			
MN Jurisdiction	99,028,174		77,285,867
LP - Demand (60% of Total Costs)	36,599,941		28,716,089
LP - Energy (40% of Total Costs)	24,399,961		19,144,060
LP Total Costs	60,999,902		47,860,149
All Other Retail Classes	38,028,272		29,425,718
Billing Determinants			
LP kW-month	716,608		715,217
LP kWh	6,037,136,000		5,998,692,000
All Other Retail Classes kWh	3,245,508,000		3,310,820,000
LP Demand Adder (cents/kW-month)	4.26		3.35
LP Energy Adder (cents/kWh)	0.404		0.319
All Other Retail Classes Energy Adder (cents/kWh)	1.172		0.889

Source: Supplement, 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-14-962**

Dated this 11th day of March 2015

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	Yes	OFF_SL_14-962_M-14-962
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_14-962_M-14-962
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_14-962_M-14-962
Margaret	Hodnik	mhodnik@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_14-962_M-14-962
Lori	Hoyum	lhoyum@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_14-962_M-14-962
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_14-962_M-14-962
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_14-962_M-14-962
James D.	Larson	james.larson@avantenergy.com	Avant Energy Services	220 S 6th St Ste 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_14-962_M-14-962
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_14-962_M-14-962
Susan	Ludwig	sludwig@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_14-962_M-14-962
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_14-962_M-14-962

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Herbert	Minke	hminke@allete.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_14-962_M-14-962
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_14-962_M-14-962
Andrew	Moratzka	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_14-962_M-14-962
Jennifer	Peterson	jjpeterson@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_14-962_M-14-962
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_14-962_M-14-962
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_14-962_M-14-962
Eric	Swanson	eswanson@winthrop.com	Winthrop Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_14-962_M-14-962
Karen	Turnboom	karen.turnboom@newpagecorp.com	NewPage Corporation	100 Central Avenue Duluth, MN 55807	Electronic Service	No	OFF_SL_14-962_M-14-962
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	No	OFF_SL_14-962_M-14-962