Minnesota Public Utilities Commission

Staff Briefing Papers

Meeting Date: May 14, 2015 .... **Agenda Item # **5**

Company: Minnesota Power

Docket No. E-015/M-14-349
In the Matter of Minnesota Power's Request for Approval of its 2014 Renewable Resources Rider Factors

Issues: Should the Commission approve Minnesota Power's proposed 2014 Renewable Resources Rider rate factors?

What is the initial cost cap for the Bison 4 project and what should it be compared to in determining whether Minnesota Power is within the cap?

How should North Dakota Investment Tax Credits be handled in the calculation of the rider revenue requirements?

Staff: Sundra Bender 651-201-2247
Dorothy Morrissey 651-201-2232

Relevant Documents

<u>Docket No. E-015/M-14-349</u>
Minnesota Power – Initial Filing .... April 29, 2014
Department – Comments .... September 3, 2014
Minnesota Power – Reply Comments .... September 16, 2014
Department – Response Comments .... December 17, 2014
Minnesota Power – Supplemental Comments .... January 14, 2015

<u>Docket No. E- 015/M-14-962</u>
Department – Comments at pp. 8 (ND Investment Tax Credit) .... March 11, 2015
Minnesota Power – Reply Comments at pp. 2-4 (ND Investment Tax Credits) ..... March 23, 2015

Statement of the Issues

Should the Commission approve Minnesota Power's proposed 2014 Renewable Resources Rider rate factors?

What is the initial cost cap for the Bison 4 project and what should it be compared to in determining whether Minnesota Power is within the cap?

How should North Dakota Investment Tax Credits be handled in the calculation of the rider revenue requirements?

Introduction

Minnesota Power is requesting approval to implement revised Renewable Resources Rider (RRR) rate factors to continue recovering the jurisdictional costs of several renewable energy projects (Bison 1, 2, and 3) and begin recovering the jurisdictional costs related to its fourth Bison wind project, Bison 4.

All of the projects for which Minnesota Power is seeking recovery have previously been determined eligible for recovery in other dockets. However, the Department raised two issues, a Bison 4 cost cap and the crediting of North Dakota Investment Tax Credits. Neither of these issues impacts Minnesota Power's proposed 2014 RRR rates, which the Department recommended be approved.

The Department also raised a concern about the impact the large proposed rate increases may have on ratepayers. While the Department ultimately recommended that the Commission approve Minnesota Power's proposed rates, it also offered an alternative for the Commission to consider if it wishes to mitigate the resulting rate increase. This would affect the proposed rates if adopted.

The purpose of these briefing papers is to summarize the two issues and the Department's alternative regarding smoothing rates, and to present decision alternatives.

Relevant Statute

Cost Recovery for Utility's Renewable Facilities, Minn. Stat. § 216B.1645, subd. 2a.

Background

On December 3, 2013, the Commission approved Minnesota Power's 2013 RRR rates in MP's third update to its RRR, including the Company's Bison 1, 2, and 3 wind projects, in Docket No. E015/M-13-410.

On January 17, 2014, the Commission approved Minnesota Power's Bison 4 project as an eligible energy technology under Minn. Stat. §216B.1645, in Docket No. E015/M-13-907.

On April 29, 2014, in the instant docket, Minnesota Power (Minnesota Power, MP, or the Company) filed its petition for approval of its 2014 RRR rates to recover Minnesota jurisdictional costs of its four wind facilities (Bison 1, 2, 3 and 4) and associated transmission upgrades, and the RRR tracker balance. In this petition, Minnesota Power proposed to use the same rate design approved in its last RRR filing.

On September 3, 2014, the Minnesota Department of Commerce, Division of Energy Resources (Department) filed comments. The Department concluded that all of the projects for which Minnesota Power is seeking recovery in its Petition are eligible for cost recovery. The Department also concluded that MP's rate design is the same approach approved in MP's last two RRR dockets and is reasonable. However, the Department stated that the Bison 4 costs recovered via the RRR should be limited to the costs contemplated in Docket No. E015/M-13-907, the Bison 4 cost eligibility docket. The Department also recommended that the Commission consider requiring the Company to stretch the recovery of its tracker balance over a period of two years if it wishes to mitigate the rate impact of the proposed rate increase.

On September 16, 2014, Minnesota Power filed reply comments.

On December 17, 2014, the Department filed response comments and raised a new issue with respect to the crediting of North Dakota Investment Tax Credits.

On January 14, 2015, Minnesota Power filed supplemental comments.

Bison 4 Cost Cap

Docket No. 09-1048

The Commission set a standard for evaluating rider project costs going forward in Xcel's Transmission Cost Recovery Rider (TCR Rider) docket, Docket No. E002/M-09-1048. The Commission stated in its April 27, 2010 Order in that docket 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.

In the current proceeding, there is disagreement between the Department and Minnesota Power on the amount of the initial estimate for Bison 4.

Docket No. 13-907

According to Minnesota Power, the initial cost estimate included in its Bison 4 cost eligibility filing,[1] was approximately $345 million of total projected capital costs. Minnesota Power currently forecasts the project will be completed within budget. Minnesota Power disagrees with the Department's interpretation of the cost cap being any number other than the total project cost as stated in the initial cost eligibility filing, which in the case of Bison 4 is $345 million. In its reply comments, Minnesota Power compared this $345 million to the capital expenditures and AFUDC net of internal costs included in its current petition of approximately $337.9 million.

According to the Department, capital expenditures on Bison 4 of $340.9 million, exceeded projected capital expenditures from Bison 4's cost eligibility filing of $339.7 million. The $339.7 million used by the Department is not found in the official record of the Bison 4 cost eligibility docket. Rather, it came from the financial model used to calculate the annual revenue requirement numbers included in Attachment 2 to the Department's November 12, 2013 Comments in that docket. Further, the Department believes the cost cap for Bison 4 in terms of rider recovery should exclude internal costs and include AFUDC. That amount, also taken from the financial model used to calculate the annual revenue requirements in the Bison 4 cost eligibility docket, according to the Department, is $337,681,343. The Department compared these initial estimate numbers to the corresponding numbers included in the current petition in Table 3 of its response comments, reproduced below.

Docket No. 14-349

The following table is copied from page 4 of the Department's December 17, 2014 response comments.

Table 3
Comparison of Department's Revised Cost Cap and Actual Cost Estimates
($)

Line No.		Cost Eligibility Filing	2014 RRR Filing	Difference
		a	b	c
1	Capital Expenditures	339,664,512	340,933,908	(1,269,396)
2	Internal Cost	(4,911,968)	(4,266,310)	(645,658)
3	AFUDC	2,928,799	1,242,807	1,685,992
4	Total for Cost Recovery	337,681,343	337,910,405	(229,062)

a - Docket No. E015/M-13-907 - The Department notes that this data is not in the official record in the Bison 4 cost eligibility Docket. It is 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.

b - Petition, Exhibit B-3

[1] Docket No. E015/M-13-907.

Based on the above comparison, the Department concluded that Minnesota Power is $229,062 over the initial cost cap. The Department recommended that the Bison 4 costs be capped at $337.7 million.

Staff notes that the Commission's January 17, 2014 Order in the Bison 4 cost eligibility docket, Docket No. E015/M-13-907:

- Approved the investment and expenditure for Bison 4, under Minn. Stat. §216B.1645, as requested by MP in its petition and detailed by the Department in Attachment 2 to its comments.

- Limited MP's Bison 4 cost recovery, under Minn. Stat. §216B.1645, subd. 1, through the renewable rider to the amounts of the initial cost estimates included by the Company in its petition in this matter, and detailed by the Department in Attachment 2 to its comments. The Company will have the opportunity to seek recovery of other costs on a prospective basis, with no deferred accounting, in a subsequent rate case.

Attachment 2 to the Department's comments in the 13-907 cost eligibility docket showed estimated annual revenue requirements, but did not show estimated capital investments and expenditure. The initial cost estimate included in the Company's petition in terms of total project costs was $345 million. The initial cost estimate detail underlying the calculation of the revenue requirements in the Department's Attachment 2 and used to compare the Bison 4 option with other options was apparently something else—total costs of $342,593,311,[2] and total costs net of internal costs of $337,681,343.[3] However, these numbers are not in the official record in the Bison 4 cost eligibility docket.

PUC Staff Discussion

Should the initial cost estimate be the $345 million contained in the narrative of the Company's petition in the cost eligibility docket, or should it be the numbers contained in the financial model used to compare costs of competing options in the cost eligibility docket? If the numbers contained in the financial model should be used, which numbers specifically should be used to establish the cost estimate: (1) the total cost of capital expenditures plus AFUDC; (2) capital expenditures only; or (3) the net cost of capital expenditures less internal costs, plus AFUDC?

Minnesota Power argued that the initial cost cap is the $345 million stated in the Company's petition in the cost eligibility filing. Based on Minnesota Power's reply comments in the instant docket, it is staff's understanding that the $345 million represented total (before deduction for internal costs) capital investment plus AFUDC. However, a breakdown of the two amounts was not provided. The total capital expenditures ($340,933,908) plus gross AFUDC ($1,254,075), before deductions for internal costs and associated AFUDC, included in the 2014 RRR filing is $342,187,983. Thus, if the $345 million is used as the cost cap, as of this 2014 RRR filing, MP is under the cap. Likewise, if the cost cap is set based on comparative numbers from the model,

[2] DOC response comments at page 5, Table 4, column b.
[3] DOC response comments at page 4, Table 3, column a.

total capital expenditures of $339,664,512 plus AFUDC of $2,928,799 for a total of $342,593,311, MP would still be under the cap as of the 2014 RRR filing.

The Department recommended that the initial cost cap be based on the financial model provided by Minnesota Power (but not in the official record) and used to determine the revenue requirements detailed in Attachment 2 to the Department's comments in the cost eligibility docket. Initially, the Department recommended that total capital expenditures should be limited to the total capital expenditures listed in the model, $339.7 million. If the cost cap were set based on the $339.7 million, MP would be over the cost cap in the 2014 RRR filing with total capital expenditures of approximately $340.9 million. Subsequently, the Department revised its recommendation and recommended that the Bison 4 cost cap in terms of rider recovery be set at the net (capital expenditures, less internal costs, plus net AFUDC) amount from the model of approximately $337.7 million. The net costs included in the 2014 RRR filing exceed the net costs in the model by $229,062. While this amount would not impact the proposed rates in this proceeding, it would mean that MP has already reached the Bison 4 cost cap if the net $339.7 million is adopted as the cost cap.

In a cost eligibility proceeding, the Commission may wish to consider total estimated costs, not just the net amount that may ultimately be flowed through the rider. Thus, regardless of whether it uses the $345 million from the narrative of the cost eligibility petition, or numbers from the financial model used to compare options later in the cost eligibility proceeding, the Commission may want to set the cost cap based on totals before deduction for internal costs. However, if the Commission does set the cost cap based on totals, the appropriate comparison to determine if MP has exceeded the limit would be the totals before deduction for internal costs and associated AFUDC, not the net amount MP used as a comparison.

In determining whether to use the $345 million from the narrative of the cost eligibility petition or numbers from the financial model, the Commission may want to consider that there is no breakdown of the $345 million provided and no explanation for why, if that was MP's actual total cost estimate, it used something else in the modeling used to compare options.

Staff notes that the difference between the $345 million included in the text of the cost eligibility filing and the comparative amount from the financial model (capital expenditures plus AFUDC) of $342,593,311 is $2,406,689, or about 0.7%.

North Dakota Investment Tax Credits

Minnesota Power's investments in the Bison wind projects generate North Dakota Investment Tax Credits (ND ITCs). Minnesota Power expects to generate a total of approximately $113 million in ND ITCs as a result of these projects. However, Minnesota Power projects that it will not have enough taxable income in North Dakota to be able to use all of the tax credits it expects to generate.

Minnesota Power projects that the ALLETE, Inc. and subsidiaries consolidated group is forecasted to use approximately $22 million of ND ITCs over the respective ND ITC carryforward periods. Minnesota Power's jurisdictional activity is forecasted to use approximately $10.7 million of the estimated $22 million. The difference of approximately $11.3 million, is attributable to the apportionment and income impacts of affiliated companies included in the ALLETE Inc. and subsidiaries consolidated group.

Minnesota Power proposed to credit the Minnesota-jurisdictional ratepayers (rider revenue requirement) for the amount of ND ITCs that would be used by Minnesota Power MN jurisdictional income, as they are used, based upon a separate "return-based" calculation. The Company does not propose to credit to Minnesota-jurisdictional ratepayers any benefit derived from the use of ND ITCs to offset ALLETE Inc.'s non-jurisdictional tax liability.

Minnesota Power also stated in response to a staff information request that:

> It is important to note that in the event future ALLETE Inc. non-jurisdictional operations were to prevent the ALLETE Inc. group from ever using any ND ITCs (presumably due to tax losses for the entire ND ITC carryforward period), Minnesota Power would still credit the Minnesota-jurisdictional ratepayers for the amount of ND ITC that would be used by the Minnesota Power MN jurisdictional income, based upon a separate "return-based" calculation.

The Department considers Minnesota Power's proposal -- to consume the amount of ND ITCs necessary to reduce Minnesota Power's North Dakota taxable income to zero, credit the Company's ratepayers for those tax savings, and then give all remaining ND ITCs to Minnesota Power's affiliates to use for the benefit of ALLETE's shareholders — to be unreasonable.

According to the Department, all of the ND ITCs available to Minnesota Power and ALLETE are the result of Minnesota Power's investments in the Bison wind projects, which are funded largely by MP's ratepayers. Therefore, the Department stated, the consumption of ND ITCs by affiliates of Minnesota Power would represent a benefit to shareholders paid for by ratepayers, for which ratepayers would receive no compensation.

Because MP's ratepayers are funding the capital investments which are generating the ND ITCs that Minnesota Power's affiliates will consume, the Department recommended that the Commission require Minnesota Power to credit to revenue requirements all ND ITCs used in ALLETE's consolidated North Dakota tax returns, not just the credits consumed by Minnesota Power on a stand-alone basis.

Minnesota Power disagreed with the Department's recommendation that the Company be required to credit ratepayers for all ND ITCs used by Minnesota Power's affiliates via ALLETE's consolidated North Dakota tax return. Minnesota Power stated:

> The Commission has clearly stated that stand-alone tax treatment should be applied to Minnesota public utilities as stated in Xcel Energy's Docket No. E002/GR-05-1428. However, the Company does agree with the Department's recommendation to consider this issue in Minnesota Power's 2015 Renewable Resources Rider Petition [Docket No. E015/M-14-962]. Neither Minnesota

> Power, nor any ALLETE subsidiary, utilized any North Dakota ITCs in the period covered by this filing. Additionally, ALLETE is not expected to be able to utilize any North Dakota ITCs until approximately 2018. Therefore, any decision made on the utilization of North Dakota ITCs would have no impact on this current Docket.

<u>PUC Staff Discussion</u>

The Department recommended that MP be required to credit ratepayers for all ND ITCs used by MP and any of its affiliates via ALLETE's consolidated North Dakota tax return. However, it also stated that "it may be most efficient for the Commission to address the timing of when ND ITCs would be returned to ratepayers in Docket No. E015/M-14-962."[4] MP agreed with the Department's recommendation for the Commission to instead consider ND ITC utilization in the 2015 RRR docket.

Because this issue came up in response comments, and because it does not affect the proposed rates, the Commission may wish to delay consideration of the issue to the 2015 RRR proceeding in Docket No. E015/M-14-962.

Staff believes there is appeal to the Department's argument that giving all the remaining ND ITCs to MP's affiliates to use for the benefit of ALLETE's shareholders when the ITCs have been funded largely by MP's ratepayers is unreasonable. However, staff also agrees with MP that in rate cases the Commission has generally taken the position that stand-alone tax treatment should be applied.[5]

One could argue that the Bison ND ITCs are MP's. To the extent they are realized by offsetting non-jurisdictional taxes, one could extend the argument that the non-jurisdictional part of ALLETE should recognize the stand-alone income tax expense and MP should recognize credit for the realized ND ITCs. That is, effectively, charge (bill) the non-jurisdictional part of ALLETE for the use of MP ND ITCs and reflect the credit (revenues) on MP.

Minnesota Power's State Tax Allocation Agreement, approved with conditions in Docket No. E015/AI-98-1201, states in part:

> 4. C. If any Subsidiary shall have a net operating loss or unused tax credits on a separate return basis, which losses or unused tax credits are used on the unitary return, MP shall pay to such Subsidiary the amount by which the taxes of the Group are less by reason of including the Subsidiary in the Group. In the event MP owes an amount to a Subsidiary, MP shall pay such amount to the Subsidiary not later than 60 days after filing of the state unitary income tax return of the Group, including proper extensions.

This should work the same on the ALLETE consolidated return and ALLETE should have to pay

---

[4] MP's 2015 RRR docket.

[5] See Docket No. E002/GR-05-1428 September 1, 2006 FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER; ORDER OPENING INVESTIGATION at pages 21-24, and Office of Administrative Hearings FINDINGS OF FACT, CONCLUSIONS AND RECOMMENDATION at pages 33-39.

the MP utility the amount by which the taxes of the Group are less by reason of including MP in the Group. In this case it appears that MP the utility has unused tax credits (ND ITCs) that are used on the unitary ND return. Thus, one could argue that the non-jurisdictional portion of ALLETE should pay MP the utility for the use of the credits. And these "payments" or revenue credits should be included in the rider revenue requirements.

Staff notes that the issue in the 2005 Xcel rate case[6] cited by MP was almost the opposite circumstance of what we have here. In that case, the Commission determined that rate case taxes should be based on a stand-alone basis and should not reflect the fact that Xcel on a consolidated basis had an NOL that reduced its tax liability. Even though the NOL was monetized by offsetting taxable income and the resulting taxes that would have otherwise been due from the regulated operations, it was determined that the NOL for ratemaking purposes should stay with Xcel's non-regulated operations.

Here we have utility tax credits that are expected to only be monetized by offsetting them against the non-jurisdictional tax liability of the consolidated corporation. One could argue that on a stand-alone basis the utility has zero tax expense and the non-jurisdictional operations of ALLETE have North Dakota income tax expense. Further, to the extent that MP's ND ITCs are used to offset the non-jurisdictional income tax expense, one could argue that the credits (or in the alternative revenue credits) should be recognized on a stand-alone basis by the utility where the ND ITCs were earned. In the Xcel case, the tax liability was the jurisdictional utility's liability and the NOL deduction stayed with the non-regulated affiliate although on the consolidated return the NOL was used as a deduction against utility income. Here, the taxes are the non-jurisdictional affiliate's liability, and the tax credits are the jurisdictional utility's credits and should be recognized as such even though on the consolidated return they are used to offset the tax liability of the non-jurisdictional affiliate.

Staff agrees with MP that the apportionment and income impacts of affiliated companies included in the ALLETE Inc. and subsidiaries consolidated group should not be attributed to MP.

Staff does not believe the Commission should deviate from the stand-alone method of calculating income tax expense in this case. Recently, the Department supported and the Commission upheld the principle of setting utility rates on a stand-alone basis in the Dakota Electric rate case, Docket No. E111/GR-14-482.[7]

However, on a stand-alone basis the Commission may want to consider several questions: Whose credits are they, ALLETE's or MP's? Who should record the deferred tax asset amount and the valuation allowance? Since these are MP earned credits, shouldn't ALLETE be required to pay to MP "the amount by which the taxes of the Group are less by reason of including" MP in the Group. If so, these revenue credits should be included in the calculation of the revenue requirement, which is further allocated between MN Jurisdictional and non-jurisdictional in calculating the rider rates.

---

[6]See Docket No. E002/GR-05-1428 September 1, 2006 FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER; ORDER OPENING INVESTIGATION at pages 21-24, and Office of Administrative Hearings FINDINGS OF FACT, CONCLUSIONS AND RECOMMENDATION at pages 33-39.

[7] See Staff Briefing Papers filed April 15, 2014 in Docket No. E111/GR-14-482 at pages 25-28.

One could also argue that on a stand-alone basis, MP would receive no benefit from the ND ITCs that would be unused on a separate return basis.

In its reply comments, in MP's 2015 RRR proceeding, in Docket No. E-015/M-14-962, MP stated that:

> The net impact of utilizing ND ITCS for MP's customers will always be zero, since by definition, the credit is used to offset an income tax expense. The credit offers no benefit unless there is an offsetting income tax expense-an expense which would add to revenue requirements.

Further, MP explained that it follows the Commission's position in the 2005 Xcel rate case and stated:

> In that Docket [E002/GR-05-1428] the Commission gave guidance regarding the inclusion of subsidiary revenues and guidance for computing income tax expense. The Commission stated "Any sharing of benefits is inevitably accompanied by the sharing of risks, which is why the Commission adopted and continues to enforce strict "stand-alone" allocation principles." The Commission stated the stand-alone method is intended to accurately reflect the cost of utility service because it matches the regulated income tax expense to the regulated revenues and expenses. The stand-alone method also supports the policy of maintaining financial separation between regulated and unregulated businesses so utility customers are responsible only for the costs of providing utility service.
>
> When the historical separation between regulated and unregulated operations is breached, this fundamental principle of cost separation is violated. The Department's recommendation to use revenues from unregulated operations to utilize credits on behalf of regulated operations is a breach of this historical separation. Additionally, it is inconsistent rate-making policy to require that the deferred tax assets from NOLs included in rate base be the lower of stand-alone or consolidated while requiring that the stand-alone position be ignored for ND ITC usage. If the Commission decides to dispense with the stand-alone position, there could be unintended repercussions associated with dispensing of the stand-alone position for other purposes, and could open the door to multiple consequences not contemplated in this Docket.

While staff agrees that income tax expense should be calculated on the stand-alone method, the Commission may want to ask MP: (1) Why the other part of ALLETE that uses the MP ND ITCs should not pay MP for the use of those credits, since on a stand-alone basis that part would have an income tax expense? and (2) Why those proceeds for the use of the ND ITCs should not be included in the calculation of the rider revenue requirement?

Investment tax credits are earned by investment in qualifying property. They are only recognized to the extent they are anticipated to be used to offset (reduce) income tax expense.

Generally, the test as to whether the ND ITCs are jurisdictional or non-jurisdictional is based on whether the expenses that generate the deduction are used to determine the jurisdictional services's rates.[8] It could be argued that since utility customers are responsible for the costs of providing utility service, which includes the return on investment and depreciation expense associated with the investments on which the ND ITCs were earned, they are entitled to the tax benefits associated with those costs regardless of whose tax expense the ND ITCs were used to offset.

In Minnesota Power's 2011 Transmission Cost Recovery (TCR) rider proceeding, Docket No. E015/M-11-695, the Department concluded that, given that Minnesota Statutes §216B.03 requires that, "Any doubt as to reasonableness should be resolved in favor of the consumer," the net operating loss accumulated deferred income tax asset (ADITA) amount added to rate base each year should be based on the lower of the stand-alone and consolidated methods.[9] In that proceeding, the Commission required[10] MP to:

> use a hybrid approach when accounting for NOLs in its riders. That is, the NOL accumulated deferred income tax asset amount added to rate base each year should be based on the lower of the stand-alone and consolidated methods. The use of the consolidated method of tax calculation only applies to a rider with an NOL included in the calculation.

Given that Minnesota Statutes §216B.03 requires that, "Any doubt as to reasonableness should be resolved in favor of the consumer," the Commission may want to consider requiring MP to calculate rider income tax expense on a stand-alone basis, but to the extent that any unused MP ND ITCs are used to reduce taxes on the ALLETE consolidated return, ALLETE shall pay MP for the use of the credits and the revenue credits shall be reflected in the rider revenue requirement calculation.

Department Alternative

The Department raised some concerns about the rate increase represented by Minnesota Power's proposed RRR Rider rates and while the Department recommended approving the RRR Rider rates proposed by Minnesota Power, it suggested an alternative should the Commission wish to mitigate the resulting rate increase.

The Department provided the following summary of the current and proposed RRR rates, showing rate increases between 79% and 103%.

---

[8] Mathew Bender Accounting for Public Utilities § 17.05[3](2).

[9] Staff notes that in the 2011 TCR proceeding, the issue appears to be the projects as a stand-alone versus MP consolidated, not total MP as a stand-alone versus ALLETE consolidated as it is in this proceeding.

[10] November 12, 2013 Order, Docket No. E015/M-11-695.

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

The above table was copied from the Department's September 3, 2014 comments.

The Department noted that a large portion of the increase, the portion attributable to the tracker balance, is expected to be short-lived. Once the tracker balance is paid off, which the Department estimated is likely to happen in the next few years, a large portion of the total costs flowing through the RRR will be eliminated, and rates may decrease nearly as quickly as they are increasing.

Minnesota Power's petition indicated that the proposed increase is expected to raise customers' overall rates (including base rates and other current riders) by approximately five to seven percent, depending on customer class. According to the Department, this increase comes on top of similarly-sized rate increases that took effect late last year pursuant to Minnesota Power's 2013 RRR petition.

The Department stated that the Commission may wish to consider ways to mitigate the proposed increase and smooth out some of the volatility expected in Minnesota Power's RRR rates over the next few years.

The Department suggested that one way to do this would be to stretch the recovery of the tracker balance over two years. In this way the increases, while still substantial, would be mitigated significantly as shown in the following table copied from the Department's response comments:

Table 4
Reproduction of Table 6 from the Department's Comments
Effects of Stretching
Tracker Balance Recovery Over Two Years

Class	Charge Type	Current RRR Rate	As Proposed RRR Rate	As Proposed Increase	With 2-Yr. Stretch RRR Rate	With 2-Yr. Stretch 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.

Minnesota Power stated that the Company is currently expending more capital on renewable and environmental retrofit projects than ever before. Project planning for these large investments was based upon the expectation of timely current cost recovery. Minnesota Power also stated that delayed cost recovery could lower its credit rating, which would harm ratepayers by raising the Company's cost of capital.

Minnesota Power requested that the Commission allow recovery of the tracker balance over a one-year time period as proposed in its 2014 RRR Factor filing. However, if the Commission determines that Minnesota Power should extend the cost recovery period, the Company requested that the Commission approve a carrying charge at Minnesota Power's authorized rate of return form its last general rate case.

In its response comments, the Department stated, "it seems that the added financing costs associated with an extended tracker balance recovery period would warrant some carrying charge to compensate the utility for the additional financing costs it will incur." The Department provided a discussion on the appropriate level of any carrying charge that may be applied, but did not offer a clear recommendation on a rate to be used.

One of the items the Department discussed was the Commission's September 26, 2014 Order in Docket No. E-017/M-14-201 (Otter Tail's 2014 CIP docket). In that docket, the Commission approved a Conservation Cost Recovery Adjustment designed to spread tracker-account recovery over two years instead of one, and granted Otter Tail a carrying charge at Otter Tail's cost of short-term debt as a way to balance advantages offered by rider treatment with the extra financing costs associated with the extended recovery period. However, in the same Order, the Commission distinguished that the CIP financial incentives making up the bulk of Otter Tail's CIP tracker account "are not the kind of costs—out of pocket costs—for which rate-of return treatment can be most readily justified."

Ultimately, the Department recommended that the Commission approve Minnesota Power's proposed RRR rates, which do not extend the recovery period for the tracker balance. Staff agrees with this recommendation.

Decision Alternatives

2014 Renewable Resource Rider (RRR) Rates

1. Approve Minnesota Power's proposed 2014 RRR rates effective the first of the month following the Commission's Order. [Minnesota Power and Department] or

2. Require Minnesota Power to recalculate its proposed rates to reflect stretching the recovery of its tracker balance over a period of two years and approve the resulting rates [Department alternative]; and

   a. approve a carrying charge on the tracker balance at Minnesota Power's authorized rate of return, 8.18 percent; [MP] or
   b. approve a carrying charge on the tracker balance at Minnesota Power's effective 12-month short-term debt rate as of September 22, 2014 of 1.6567 percent;[11] or
   c. approve a carrying charge on the tracker balance at some other rate determined by the Commission; or
   d. do not approve a carrying charge on the tracker balance.

3. Require Minnesota Power to make a compliance filing including updated tariff sheets within 30 days of the Commission's Order. [Note: If alternative 2 above is selected. The compliance filing should include the new, updated RRR rates.]

Bison 4 Cost Cap

4. Find that the cost cap for Bison 4 is Minnesota Power's original total capital cost estimate of $345 Million [MP] and that this should be compared to:

   a. Capital expenditures and AFUDC net of internal costs. [MP]
   b. Capital expenditures and AFUDC before netting internal costs and associated AFUDC. [Staff]
   c. Capital expenditures.

5. Find that the cost cap for Bison 4 for rider recovery purposes is the initial capital expenditure amount used for modeling purposes of $339,664,512, less estimated internal labor costs of $4,911,968, plus net AFUDC amounts of $2,928,799 for a total net initial cost cap of $337.7 million. This should be compared to the current net amount. [Department]

6. Find that the cost cap for Bison 4 is $342.6 million, the initial capital expenditure amount

[11] See the Department's December 17, 2014 response comments, in this docket, at pages 10-11.

used for modeling purposes of $339,664,512 plus the initial AFUDC amount used for modeling purposes of $2,928,799, and that it should be compared to the current amounts for capital expenditures and gross AFUDC before netting internal costs and associated AFUDC. [Staff]

North Dakota Investment Tax Credits (ND ITCs)

7. Find that only North Dakota Investment Tax Credits used by Minnesota Power should be credited to the rider revenue requirement calculation. [MP]

8. Require Minnesota Power to credit the rider revenue requirement calculation for all MP ND ITCs used in ALLETE's consolidated North Dakota tax returns, not just the credits consumed by MP on a stand-alone basis. [Department]

9. Require ALLETE to pay Minnesota Power for the amount by which the taxes of the consolidated Group are less by reason of including MP in the Group, and require MP to credit the rider revenue requirement calculation each year for (a) all ND ITCs that would be used on Minnesota Power's North Dakota tax return on a stand-alone basis, and (b) revenues received for all additional MP ND ITCs used to reduce the taxes on ALLETE's consolidated North Dakota tax return. [Staff]

10. Take no action at this time since there is no effect on the currently proposed rates.