STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
John Tuma	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC SERVICE IN THE STATE OF MINNESOTA

Docket No. E002/GR-13-868

PETITION FOR RECONSIDERATION

Northern States Power Company, doing business as Xcel Energy, respectfully submits this Petition for Reconsideration to the Minnesota Public Utilities Commission's May 8, 2015 Findings of Fact, Conclusions, and Order in this docket.[1] At the outset, we note that the Company takes only one exception to the Commission's Order with respect to the revenue decoupling mechanism's three percent cap and believes that the remainder of the Order represents a reasonable outcome to this proceeding that will lead to just and reasonable rates. However, and in addition to the exception we take regarding the Commission's decision on revenue decoupling, we also seek reconsideration and/or clarification of two other aspects of the Order. We bring forward these two additional issues now so that we may help ensure the timely and accurate implementation of final rates as we prepare to file our next rate case in November of this year.

First, we seek to clarify that the Monticello Extended Power Uprate (EPU) Project is used and useful as of January 1, 2015 and is appropriately included in 2015 rate base. Second, we seek to clarify the calculation of the revenue deficiency in the Order, based on applying the correct rate of return to our entire 2015 rate base. And, third, we seek reconsideration and clarification of certain aspects of the revenue decoupling mechanism authorized by the Order in light of our upcoming 2016 test year rate case.

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1 *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, Docket No. E002/GR-13-868 (May 8, 2015) ("Order").

Our Request meets the Commission's standards as set forth in Minn. R. 7829.3000. Commission action on this request will help to ensure that our calculation of final rates and implementation of the revenue decoupling mechanism will be consistent with national practice and the Commission's intent. Granting our request will also help to mitigate any delay in implementation of final rates, as well as avoid any confusion that may result from implementing our revenue decoupling mechanism at the same time that we implement interim rates and/or final rates as part of our upcoming rate case.

1. The Monticello EPU is In Service

The Order provides that "if the EPU is not in service by January 1, 2015, the Company should refund any excess amounts collected in rates through the refund mechanism for the multiyear rate plan."[2] This is consistent with the Administrative Law Judge's (ALJ) recommendations,[3] which the Commission adopted.[4] While we believe the Order and ALJ Report make plain when the EPU would be in service in 2015, we recognize that placing the EPU in service was contested in this rate case, as well as the prior two rate cases. For that reason, the Company respectfully requests that the Commission clarify that the Monticello EPU is in service as of January 1, 2015 and that, therefore, no refund is due under the multiyear rate plan refund process.

We believe the Monticello EPU is in service as of January 1, 2015, because plant ascension to EPU levels is no longer subject to approvals from the Nuclear Regulatory Commission (NRC). Both the Commission and the ALJ determined that the Monticello EPU was not used and useful in 2014 because, "the Company still did not have the NRC's permission to operate Monticello at the full 671 MW uprate level."[5] The Company understands this finding to mean that once the Company no longer requires NRC review or approval to continue the ascension of the Monticello plant to full EPU levels, the Monticello EPU will be considered in service for rate making purposes.

Monticello had been operating at uprated conditions (generally between 640 MW and 656 MW) from December 2014 until the current Spring Outage that began in April,

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[2] Order at 15.

[3] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION at 21, Docket No. E002/GR-13-868 (Dec. 26, 2014) ("ALJ Report").

[4] Order at 14.

[5] Order at 14-15; ALJ Report at 20 ("[h]owever, until the Company receives authorization from the NRC to operate at the 671 MW level, the plant is not able to provide the 71 MW of additional cost-effective power that the EPU was intended to provide when the Commission approved the Certificate of Need").

2015.[6] The Company has successfully passed all data collection requirements of its Operating License without issue and has received NRC concurrence. The Company therefore does not require any additional NRC approvals or authorizations to operate the plant at the full uprated levels. In other words, the Company has full authority from the NRC to operate the Monticello plant at 671 MW should operational conditions warrant. Consequently, under the Commission's Order, the Monticello EPU is in service and no refund is due.

We recognize that the Monticello Plant has not yet operated at 671 MW. However, achieving 671 MW does not mean that the Monticello EPU is not in service.[7] The ALJ's findings, which were adopted by the Commission, do not require that the plant operate at the full 671 MW in order to be used and useful:

> In reaching this conclusion, the Administrative Law Judge is not suggesting that the plant must operate continuously at 671 MW once the Company receives NRC approvals to operate at that level in order for the EPU to be "used and useful." The Administrative Law Judge recognizes that the plant may operate at a lower level at times for operational reasons or because of a planned outage.[8]

We believe this finding makes sense from several different perspectives. First, it recognizes that operational issues unrelated to the EPU can arise and limit the plant's output. This is in fact the situation with Monticello; Monticello has not yet operated at 671 MW as a result of a mechanical issue unrelated to the EPU Project or NRC restrictions. The mechanical issue with turbine controls occurred while ascending the Monticello plant to 671 MW. Instead of taking an unforced outage to fix the issue, we chose to address it during the next planned outage, which occurred this spring. Once the planned outage is complete, there is some concern that water temperatures in the Mississippi River could be too high to operate the plant at 671 MW, which

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[6] We note that on January 10, 2015, the Monticello Plant fell below these operating levels. This was not due to any issues related to the EPU ascension, but rather was due to MELLLA+ testing.

[7] *State of North Carolina, ex. Rel. Utilities Commission v. Conservation Council of North Carolina*, 307 S.E.2d 375, 378 (N.C. Ct. App. 1983) ("[a] power plant can be 'used and useful' without operating at full capacity"); *City of Evansville v. Southern Indiana Gas and Electric Company*, 167 Ind. App. 472, 517-519 (1975) (holding that a flexible approach is required to find a plant is in service as a strict in service test "would presumably require exclusion from the rate base of plant which was out of service for routine maintenance or repair at any time during the test year"); *In re Application of Public Service Company of Colorado for a Certificate of Public Convenience and Necessity for Comanche-Daniels Park 345 kV Transmission Project*, INTERIM ORDER PARTIALLY GRANTING EXCEPTION AND REMANDING MATTER TO ADMINISTRATIVE LAW JUDGE, Proceeding No. 05A-072E, C06-0094-I (Co. P.S.C. Jan. 25, 2006) (finding that full cost of 345 kV transmission line is appropriately included in rate base even though the line is intended to be operated at 230 kV).

[8] ALJ Report at 20 (Finding 89).

could further delay achieving this output level for reasons beyond the Company's control. Consistent with the Commission's treatment of the outages at Sherco 3[9] and Black Dog Units 2 and 5,[10] the Company's AAA dockets would be the appropriate venue in which to review the impacts of operating conditions preventing operations at 671 MW on overall system costs.

This finding also promotes sound public policy – namely, the Company's operation of the plant in a safe and reliable manner as opposed to achieving an output threshold by any means necessary. Safe operation of the Monticello Plant is a key priority for the Company, and ensuring operational conditions are within reasonable tolerances and planned outages are appropriately and timely taken are part of ensuring safe operations.

In closing, the Company respectfully requests that the Commission clarify its Order and find that the Monticello EPU is in service in 2015.

2. Cost of Debt for 2014 Rate Base Carried Forward to 2015

We respectfully seek correction of the 2015 calculation of the Company's Gross Revenue Deficiency on page 94 of the Commission's Order. Our primary concern is that the Gross Revenue Deficiency calculation in the Order does not apply the Company's approved 2015 cost of capital to the entire rate base for 2015 (although it does apply the updated cost of capital to 2015 Step projects). As a result, our revenue requirement for 2015 is lower than it should be. Applying the updated cost of capital to the entire 2015 rate base was a resolved issue between the Company and the Department of Commerce during the proceeding. We therefore respectfully request that the Commission clarify its Order by updating the cost of capital for the entire 2015 rate base, which will correct the Company's approved jurisdictional retail-related revenues for 2015.

In the course of the multiyear rate plan, the final revenue requirement for 2015 is based on the approved 2014 rate base plus the capital projects in the 2015 Step. To calculate the revenue deficiency corresponding to the 2015 rate base, the Company initially applied a single cost of debt to rate base for 2014 and 2015. In response to Department witness Dr. Eilon Amit's request in Direct Testimony,[11] we then updated the separate costs of debt for 2014 and 2015 in Mr. George Tyson's Rebuttal.[12] Dr. Amit subsequently accepted these updated costs of debt, which were incorporated

[9] Order at 47.
[10] Order at 48.
[11] Ex. 400, Amit Direct at p. 46-47.
[12] Ex. 31, Tyson Rebuttal at 25-30.

into Department witness Mr. Dale Lusti's Surrebuttal and evidentiary hearing cost of service schedules.[13]

Mr. Lusti's schedules show the methodology he used to calculate the Company's 2015 revenue deficiency, and illustrate that he applied the updated cost of capital to the entire 2014 rate base plus 2015 Step.[14] The Company's post-hearing and compliance financial schedules in this proceeding have likewise showed the parties' agreement to apply the updated cost of debt to all capital projects carrying forward from 2014 to 2015, as well as the 2015 Step projects.[15] We respectfully submit that this is the correct methodology.

However, the Gross Revenue Deficiency schedule on page 94 of the Order appears to apply the updated cost of debt solely to 2015 Step items. For the reasons discussed above, we believe it is appropriate to apply the updated 2015 cost of debt to the entire rate base consistent with typical practice, the parties' agreement and the consistently-calculated financial schedules in the record of this case.

Even if it were correct to apply the updated cost of debt solely to 2015 Step projects, the amount of 2015 Operating Income (before AFUDC) stated on page 94 of the Order is not consistent with this approach. We recognize that the 2015 Step Operating Income (before AFUDC) depicted on page 94 of the Order (-$13,470) is taken from Schedule A-1, page 2 of 3, Column 3 of our April 24 compliance filing. However, this amount assumes the debt interest deduction on the entire rate base is updated for the 2015 cost of debt. Subject to other updates through compliance, the correct manner of calculation is presented on that same page of the same schedule, in Column 2.[16]

As a result of utilizing the incorrect Operating Income (before AFUDC) and applying the updated cost of debt solely to 2015 Step projects, the Company's income deficiency is understated on page 94 of the Order. In turn, the Company's 2015 Gross Revenue Deficiency is understated by approximately $3.3 million.[17]

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[13] Ex. 403, Amit Surrebuttal at 9-10, 29-30; Ex. 442, Lusti Surrebuttal at Schedule DVL-S-21; Ex. 451, Lusti Opening Statement with Attachments at Schedule DV-EH-21.

[14] Ex. 442, Lusti Surrebuttal at Schedule DVL-S-21; Ex. 451, Lusti Opening Statement with Attachments at Schedule DV-EH-21.

[15] *Issues List* at 16-17 (Oct. 7, 2014); *Xcel Energy Revised Financial and Rate Design Schedules* [to reflect ALJ Report] (Jan. 9, 2015); *Xcel Energy Compliance Filing – Preliminary Schedules* at Schedule A-1 at 2 and 3 (April 24, 2015).

[16] *Xcel Energy Compliance Filing – Preliminary Schedules* at Schedule A-1 at 2 and 3 (April 24, 2015). Please note that secondary calculations for Net Operating Loss and Cash Working Capital are also impacted. Attachment A to this Petition shows the exact implementation.

[17] The Company's permitted 2015 jurisdictional total retail-related revenue in Order Point 1 (p. 97) is also understated, but by a different amount than the Gross Revenue Deficiency. We have not been able to replicate calculation of the 2015 revenue stated in Order Point 1.

To facilitate clarification, we attach a Gross Revenue Deficiency schedule as Attachment A to this Petition illustrating both the 2015 Gross Revenue Deficiency based on the correct cost of debt calculation, and an alternate calculation that would be mathematically accurate if the updated 2015 cost of debt was only applied to the 2015 Step projects. Because proper calculation of the cost of debt represents a material correction to the Company's revenue deficiency, we respectfully request that the schedule on page 94 be updated to reflect application of the 2015 cost of capital to the entire 2015 rate base, and that Order Point 1 be revised as follows:

> Xcel's Electric Utility is entitled to increase Minnesota jurisdictional revenues by $58,908,000 to produce jurisdictional total retail-related revenue of $2,885,909,000 for the test year ending December 31, 2014 and to produce jurisdictional total retail-related revenue of ~~$2,992,385,000~~ $2,995,708,000 for the 2015 Step.[18]

3. Decoupling

We ask that the Commission reconsider and clarify aspects of the Order related to decoupling. We are concerned that some of the modifications to the Company's decoupling proposal were not evaluated through testimony, while others may present implementation difficulties in light of the anticipated filing of our next rate case in November of this year. We respectfully ask the Commission to reconsider the cap that applies to decoupling adjustments and to clarify how the Company should implement the decoupling mechanism outlined in the Order in the context of a 2016 rate case.

(a) Decoupling Cap and Full Decoupling

The Order adopted a 3 percent base revenue cap on upward decoupling adjustments.[19] The Company has several concerns with this approach. First, a 3 percent base revenue cap was not evaluated in the record. Second, a 3 percent base revenue cap differs from prior caps adopted by the Commission and national practice. Finally, we are concerned that a 3 percent base revenue cap is incompatible with other elements of the decoupling mechanism as set forth in the Commission's Order. For these reasons, we respectfully request that the Commission reconsider its Order and set the

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[18] Final 2015 revenue requirement as shown in Schedule A4 of the Preliminary Compliance Filing of CCOSS and Class Revenue Apportionment Schedules on May 1, 2015, which recognizes sales and revenue from a new large commercial and industrial customer in 2015. The adjustment related to this new customer was agreed upon by the Company and the Department at the evidentiary hearing and is described in the Company's revenue calculations resulting from the ALJ recommendation filed on January 16, 2015.

[19] Order at Order Point 40 (c).

decoupling cap at 10 percent of base revenue, or adopt partial decoupling as originally proposed by the Company.

The Department analyzed four different caps: (1) a 2 percent cap calculated using base revenue *plus* fuel and all applicable riders; (2) a 3 percent cap calculated using base revenue *plus* fuel and all applicable riders; (3) a 5 percent cap calculated using base revenue only; and (4) a 10 percent cap calculated using base revenue only.[20] The Order cites to the Department's analysis as supporting the 3 percent base revenue cap:

> Here, the Commission concurs with the ALJ and the Department that the record does not demonstrate a need for a cap exceeding 3%. The Department's analysis shows that setting the cap above 3% would virtually eliminate the cap for the standard residential customer because [revenue decoupling mechanism] RDM rate increases would rarely exceed that level.[21]

However, the Department did not analyze a 3 percent base revenue cap. The 3 percent base revenue cap adopted in the Order is approximately 23 percent lower than the cap analyzed by the Department.[22] The lack of record support for a 3 percent base revenue cap supports reconsideration of the Commission's decision.[23] A 3 percent base revenue cap also deviates materially from existing decoupling caps approved by the Commission. Both CenterPoint Energy's (CenterPoint) and Minnesota Energy Resources Corporation's (MERC) decoupling mechanisms include 10 percent base revenue caps.[24] Both CenterPoint and MERC have full decoupling like the mechanism adopted in the Order. Because the 3 percent base revenue cap was not evaluated in the contested case proceedings and because the Order does not

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[20] Ex. 419, Davis Surrebuttal at 8-9.

[21] Order at 80.

[22] *See Xcel Energy Compliance Filing – Sales Actual Data and Property Tax Expense Update and Related Revenue Calculations* at Attachment D2 at 1 (Jan. 16, 2015) (showing Residential class 2015 base revenue of $747.7 million and total revenue of $960.3 million).

[23] Minn. Stat. § 216B.27, Subd. 3 ("If in the commission's judgment, after the rehearing, it shall appear that the original decision, order, or determination is in any respect unlawful or unreasonable, the commission may reverse, change, modify, or suspend the original action accordingly."); *Citizens Advocating Responsible Development v. Kandiyohi County Bd. of Commissioners*, 713 N.W.2d 817, 832 (Minn. 2006) ("Moreover, an agency ruling is arbitrary and capricious if the agency… offered an explanation that runs counter to the evidence….") (internal citations omitted); *In re Blue Cross and Blue Shield*, 624 N.W.2d 264, 277 (Minn. 2001) (requiring a rational connection between the facts found and the choice made).

[24] *In the Matter of an Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas For Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 48 (June 9, 2014); *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G007, G011/GR-10-977, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 13 (July 13, 2012).

address why it is reasonable to treat the Company differently than CenterPoint and MERC, the record lacks the evidence necessary to support departing from past practice.[25]

In addition, a 3 percent base revenue cap cannot be reconciled with national practice. As discussed in testimony, the majority of electric decoupling mechanisms have no caps.[26] Those mechanisms that do include caps are calculated using total revenue.[27] And for the small group that calculate caps using base revenues, 10 percent – like CenterPoint and MERC – is the most common value.[28] These practices further indicate that reconsideration is warranted and support a 10 percent base revenue cap.

Finally, a 3 percent base revenue cap appears to be inconsistent with other aspects of the Order. The Order adopts full decoupling, which encompasses all deviations from the allowed usage per customer, including weather-related changes. The Order also adopts an asymmetrical cap: all revenues that exceed authorized revenue per customer must be credited back to ratepayers, but the Company can only recover revenue shortfalls up to the cap. Revenue shortfalls that exceed the cap tied to conservation and efficiency effects may also be recovered.[29] This leads to a situation where, all else being equal, the Company could be required to issue refunds for all weather-related increases in usage per customer, but would be prevented from fully recouping weather-related decreases in usage per customer.

In contrast, partial decoupling, when coupled with a soft cap, is symmetrical: decoupling billing adjustments would be limited to those amounts necessary to

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[25] *In re Review of 2005 Annual Automatic Adjustment of Charges for all Electric and Gas Utilities*, 768 N.W.2d 112, 120 (Minn. 2009) ("When an agency seeks to deviate from its prior decisions, the agency is charged with setting forth a reasoned analysis for the change.").
[26] Ex. 109, Hansen Direct at Schedule 2; Ex. 110, Hansen Rebuttal at 10.
[27] Ex. 109, Hansen Direct at Schedule 2.
[28] Ex. 109, Hansen Direct at Schedule 2.
[29] Order at 79-80 states as follows:

> Given these competing considerations, the Commission will pursue a middle path. Consistent with a soft cap, <u>the Commission will provide Xcel with the opportunity to recoup costs that the Company was unable to recover during the previous year due to the cap on RDM rate increases.</u> Yet this cost recovery will not be automatic; rather, Xcel will have to petition the Commission for authority to recover these costs. <u>In the petition, Xcel would have to demonstrate that its demand-side-management programs and initiatives were a substantial contributing factor to the declining energy sales that triggered the rate adjustment, and that its declining sales were not driven primarily by factors unrelated to conservation and efficiency.</u> (emphasis added)
>
> <u>This modified cap will mitigate some of the adverse consequences of a hard cap while providing assurance that large rate adjustments are in fact tied to the purposes for which the RDM was proposed: the promotion of conservation and efficiency.</u> (emphasis added)

achieve the weather normalized revenue per customer approved in this case – no more and no less.[30] The Company's proposal was also gradual, as it did not change the status quo with customers regarding weather. While that status quo may only be an "incidental result" of traditional rate design,[31] the Order departs from current practice by eliminating risk allocation. We are further concerned that it does so without accounting for the asymmetrical assignment of weather risk.[32] We believe that partial decoupling and a soft cap provide a better balance. In the alternative, setting the cap at the 10 percent of base revenue level supported in the record helps mitigate some of the risk of combining full decoupling with an asymmetrical hard cap.[33] The Company supports either modification.

(b) Implementation

We also request clarification of the Commission's ordered implementation plan for the decoupling mechanism. By way of background, the Company proposed a decoupling implementation plan that was unopposed in parties' testimony. That plan called for use of 2015 test year data to calculate baseline fixed revenue per customer and baseline fixed energy charges.[34] The baseline values would then be applied to actual customers and sales beginning in June 2015:[35]

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[30] Ex. 417, Davis Direct at 33; Ex. 109, Hansen Direct at 9-12.

[31] Order at 76.

[32] *In re Review of 2005 Annual Automatic Adjustment of Charges for all Electric and Gas Utilities*, 768 N.W.2d 112, 120 ("When an agency seeks to deviate from its prior decisions, the agency is charged with setting forth a reasoned analysis for the change.").

[33] The Company acknowledges the Commission adopted a middle path in the "hard cap v. soft cap" issue. *See* Order at 79. As it relates to weather, however, the cap remains hard because there is no opportunity to petition for recovery of weather-related shortfalls that exceed the cap. *See id.* at 79-80.

[34] Ex. 109, Hansen Direct at 9-12 and Schedule 4.

[35] Ex. 109, Hansen Direct at 14-15.

Table 1

Xcel Energy's Proposed Decoupling Implementation Schedule

Date	Event
May 2015	Commission's Final Order
June – December 2015	Measure 2015 Decoupling Deferrals
January – December 2016	Measure 2016 Decoupling Deferrals
April 1, 2016	Implement 2015 RDM Adjustment*
January – December 2017	Measure 2017 Decoupling Deferrals
April 1, 2017	Implement 2016 RDM Adjustment *
January – May 2018[36]	Measure 2018 Decoupling Deferrals
April 1, 2018	Implement 2017 RDM Adjustment *
April 1, 2019	Implement 2018 RDM Adjustment *

** In effect from April 1 through March 31.*

The Order adopted a schedule that was not discussed during contested case proceedings, and appears to create ambiguity regarding the data that should be used to calculate baseline fixed revenue per customer and baseline fixed energy charges. Further, the Company seeks guidance regarding how the implementation schedule from the Order would function in light of the Company's intention to file a 2016 rate case with interim rates effective January 1, 2016, and with final rates effective some time in 2017.

The Order provides that the start date for measuring decoupling deferrals be no sooner than January 1, 2016.[37] The Order explains that delaying the start date to January 1, 2016 is appropriate, because that date is after final rates from this case will be in effect:

> Finally, the Commission will add clarity to Xcel's proposal by establishing a start date.
>
> <u>One of Xcel's first steps in implementing revenue decoupling is measuring a baseline customer consumption level to determine how much actual sales differ from forecasted sales.</u> Consumption can vary for many reasons, including price. Xcel will set new rates through the current

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[36] Assuming pilot for the decoupling program only runs for three years, as envisioned in Order Point 40(a).

[37] Order at 71.

> proceeding, but those rates have not taken effect yet. It would make sense to delay the collection of sales data until the new rates are implemented.
>
> For purposes of calculating the first RDM adjustment, therefore, the Commission will authorize Xcel to begin collecting data on sales that occur after the Commission issues its final compliance order in this docket and the new rates take effect, but in no event sooner than January 1, 2016.[38]

However, the Order is not clear regarding what baseline data should be used to calculate deferrals. Specifically, it is unclear whether the underlined provisions only apply to the calculation of the decoupling deferrals, or if they require the Company to use 2016 data to calculate baseline fixed revenue per customer and baseline fixed energy charges. Further, given the Company's intention to file a 2016 rate case in November, 2015, the rates in place on January 1, 2016 likely will be new interim rates rather than the final rates in this case. Additionally, if the schedules from prior cases are a guide, final rates from our next rate case will become effective in 2017, which could coincide or occur after the April 1, 2017 implementation date for the RDM mechanism.

The Commission could take several different routes to clarify the implementation plan. One option would be to keep the January 1, 2016 start date for calculating decoupling deferrals and set the baseline fixed revenue per customer and baseline fixed energy charges using 2016 interim rate data. This approach is consistent with the recently approved CPE implementation plan.[39] Another option is to set the baseline fixed revenue per customer and baseline fixed energy charges using 2015 test year data from this case. Since rates will adjust several times in the next few years (once with final rates in this case and potentially multiple times – interim and final – as part of the 2016 rate case), the Commission may also want to adopt the Company's proposed implementation schedule.[40]

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[38] Order at 75 (emphasis added).

[39] *In the Matter of an Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas For Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G008/GR-13-316, ORDER ACCEPTING DECOUPLING COMMUNICATION PLAN (Mar. 23, 2015) (approving CPE's October 14, 2014 compliance filing, which included, among other things, an explanation that proposed to update its decoupling baseline using interim rates and updated billing determinants from its anticipated August, 2015 rate case filing).

[40] Given the potential for several rate changes over the next two-and-a-half years, one option would be to allow the Company to begin calculating decoupling deferrals in June, 2015 but delay the implementation of any decoupling billing adjustments to the conclusion of the Company's next rate case.

In closing, we note that our proposal was designed with the expectation that it could be implemented during a period of relative stability. Meaning, we believed that voluntarily bringing forward a significant change to rate design would be followed by a period of time to assess and analyze the impact of implementing revenue decoupling. As this case illustrated, however, we anticipate that interested stakeholders will continue to advocate for changes to the Company's rate design as a means of addressing various issues. Under such circumstances, it may be reasonable to examine decoupling as one of many different rate designs that can promote conservation, and to determine, on a holistic basis, which rate design changes should be implemented and on what schedule.[41] We look forward to a constructive discussion with the Commission on these issues.

CONCLUSION

The Company respectfully requests that the Commission grant this Petition for Reconsideration. The Company believes the Commission's Order represents a reasonable outcome in this proceeding and that the resulting rates will be just and reasonable. Granting our request will help the Company ensure that our calculation of final rates and implementation of the revenue decoupling mechanism will be consistent with the Commission's intent and also help ensure prompt implementations of final rates. Finally, since the Company intends to file its next rate case in November of this year, clarification will help the Company prepare for its next rate case and implement decoupling within that context.

Respectfully submitted,

Northern States Power Company

May 28, 2015

[41] The Company supports the Commission's decision to broaden the discussion of rate design alternatives to all designs that promote energy conservation, reduce peak demand, and/or send more accurate, useful price signals to customers. *See* Order at 90-91.

Revenue Deficiency - Minnesota Jurisdiction
Test Year Ending December 31, 2014 and 2015 Step
($000's)

		Apply cost of debt to entire rate base		**Apply cost of debt to 2015 Step items only**	
Line No.		2014 Test Year	2015 Step	2014 Test Year	2015 Step
1	Average Rate Base	$ 6,493,649	$ 584,573	$ 6,493,649	$ 584,580
2	Rate of Return	7.34%	7.37%	7.34%	7.37%
3	Required Operating Income	$ 476,634	$ 45,031	$ 476,634	$ 43,084
4	Operating Income before AFUDC	$ 407,232	$ (13,470)	$ 407,232	$ (14,275)
5	AFUDC	$ 34,864	$ (5,509)	$ 34,864	$ (5,509)
6	Total Operating Income	$ 442,096	$ (18,979)	$ 442,096	$ (19,785)
7	Income Deficiency	$ 34,538	$ 64,010	$ 34,538	$ 62,868
8	Gross Revenue Conversion Factor	1.705611	1.705611	1.705611	1.705611
9	Gross Revenue Deficiency	$ 58,908	$ 109,176	$ 58,908	$ 107,229