MINNESOTA DEPARTMENT OF COMMERCE

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January 2, 2015

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

RE: **Response Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E002/M-14-852

Dear Dr. Haar:

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

> Northern States Power Company, doing business as Xcel Energy's Petition for approval of its 2015 Transmission Cost Recover Rider.

The petition was filed on October 1, 2014 by:

> Paul J Lehman
> Manager, Regulatory Compliance & Filings
> Xcel Energy
> 414 Nicollet Mall, 7th Floor
> Minneapolis, MN 55401

The Department recommends that the Commission:

1. not allow Xcel to include revenue requirements associated with the two out-of-state projects in the 2015 TCR,
2. allow Xcel to recover at least $950.2 million in its 2015 TCR if the Commission views the three segments of CapX2020 separately. If Commission chooses to view the CapX2020 segments as one project from the one CN proceeding, the Commission should allow Xcel to recover the requested $969.5M; and
3. not allow Xcel to recover any changes to revenues collected by MISO and passed on to Xcel associated with wholesale transmission costs and revenues recovered through Xcel's base rates as a result of FERC's actions in Docket No. EL-14-12-000.

The Department is available to answer any questions the Commission may have.

Sincerely,

/s/ ZAC RUZYCKI
Public Utilities Rates Analyst

/s/ JOHN KUNDERT
Financial Analyst

ZR/JK/lt
Attachment

MINNESOTA DEPARTMENT OF COMMERCE

# BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

# RESPONSE COMMENTS OF THE MINNESOTA DEPARTMENT OF COMMERCE DIVISION OF ENERGY RESOURCES

DOCKET NO. E002/M-14-852

## I. BACKGROUND

On August 1, 2006, Northern States Power d/b/a Xcel Energy (Xcel or the Company) filed a petition requesting approval of a Transmission Cost Recovery Rider (TCR Rider). Xcel proposed to use the TCR Rider to recover costs and revenues of renewable projects rather than the Renewable Cost Recovery (RCR) Rider, along costs and revenues of greenhouse gas projects and transmission projects, as allowed by Minn. Stat. §216B.16, subd. 7(b), which was first adopted during the 2005 legislative session.

On November 20, 2006, the Minnesota Public Utilities Commission (Commission) issued an *Order Approving Transmission Cost Recovery Rider* in Docket No. E002/M-06-1103 approving Xcel's proposed tariff for the TCR Rider with the condition that Xcel must maintain separate tracker accounts for projects approved under the renewable cost recovery statute, and those approved under the transmission cost recovery statute.

The Commission issued Orders regarding Xcel's TCR Rider in several dockets since its November 20, 2006 Order.[1] Most recently, on February 7, 2014 the Commission issued its *Order Approving 2012 TCR Project Eligibility and Rider, Capping Costs, and Modifying 2011 Tracker Report* in Docket No. E002/M-12-50 (2012 TCR Rider).

On October 1, 2014, Xcel filed its petition requesting approval of its 2014 Transmission Cost Recovery Rider (2015 TCR Rider).

[1] Docket Nos. E002/M-08-1284, E002/M-09-1048, E002/M-10-1064, and E002/M-12-50

## II. SUMMARY OF FILING

In previous Orders, the Commission approved recovery of costs of a number of projects under the Transmission Cost Recovery Statute (TCR Statute, Minn. Stat. §216B.16, subd. 7(b)), as well as projects eligible for recovery under the Renewable Cost Recovery Statute (RCR Statute, Minn. Stat. §216B.1645) and the Greenhouse Gas Infrastructure Statute (Minn. Stat. §216B.1637). The Commission also approved recovery of Midcontinent Independent System Operator (MISO) Regional Expansion Criteria Benefits (RECB) revenues and costs invoiced to the Company by MISO.

In the current petition, Xcel seeks cost recovery for five projects that the Commission previously determined were eligible for recovery under the TCR Statute. The Company does not seek recovery for any new projects under the TCR Statute, but does bring attention to two projects located outside of Minnesota for which Xcel looks to the Commission for direction regarding the timing and manner of cost recovery. Xcel does not seek cost recovery for any projects under the RCR Statute or the Greenhouse Gas Infrastructure Statute.

Xcel proposes to recover its 2015 annual revenue requirements, 2015 net RECB charges, and its 2014 true-up carryover balance, less its 2015 revenue collections. A summary of Xcel's proposed TCR revenue requirements is provided in the table below:

**Table 1: Xcel's Proposed TCR Revenue Requirements**

| Project | 2014 Forecasted Revenue Requirements | 2015 Forecasted Revenue Requirements |
|---|---|---|
| | | |
| CAPX2020 – Brookings | $33,666,872 | $44,348,614 |
| CAPX2020 – Fargo | $15,543,137 | $19,565,133 |
| CAPX2020 – La Cross Local | $1,048,412 | $3,446,516 |
| CAPX2020 – La Cross MISO | $5,867,366 | $7,374,473 |
| CAPX2020 – La Cross MISO - WI | $4,646,170 | $11,204,881 |
| Net RECB 26 & 26A Charges | ($27,282,230) | ($28,616,748) |
| Subtotal Transmission Projects | $33,489,727 | $57,322,870 |
| | | |
| TCR True-Up Carryover | ($1,379,070) | $8,464,840 |
| Total Revenue Requirement | $32,110,658 | $65,787,710 |
| Less Revenue Collections | $23,645,818 | |
| Balance Over (Under) | $8,464,840 | |

As illustrated in the table above, the remaining Minnesota revenue requirements to be recovered through December of 2015 totals $65,787,710.

The Company proposes to allocate revenue requirements within the TCR to various customer classes based on the type of demand allocation factors approved by the Commission in prior TCR filings. Within the rate classes, the Company proposed to charge its residential and commercial non-demand customers using an energy-only rate (per kWh) and its demand billed customers with a demand based rate (per kW). In this filing, street lighting customers have been removed as a separate class on the tariff sheets. The demand allocators approved by the Commission in the most recent rate case are used to calculate the proposed TCR rate factors by customer class. The test year allocation factors were changed in the final rate determination in Docket No. E002/GR-12-961 when the Commission ordered[2] that transmission cost allocation be based on system coincident summer peak demand. Xcel's approach yields the following TCR rate adjustment factors for 2015:

**Table 2: Xcel's TCR Rate Adjustments for 2015**

| Customer Group | Rate |
|---|---|
| | |
| Residential | $0.002692/kWh |
| Commercial Non-Demand | $0.002557/kWh |
| Demand Billed | $0.754/kW |

## II. DEPARTMENT ANALYSIS

### *A. STATUTORY REQUIREMENTS*

The TCR Statute, Minn. Stat. §216B.16, subd 7b contains the following provisions:

(1) allows the utility to recover on a timely basis the costs net of revenues of facilities approved under section 216B.243 or certified or deemed to be certified under section 216B.2425;

(2) allows the recovery of charges as established by federal tariff that are incurred from other utilities' transmission projects that have been determined by MISO to benefit the utility. Such charges must be offset by revenues received by the utility of its charges to other regional transmission owners, to the extent those revenues and charges have not been otherwise offset;

(3) allows a return on investment at the level approved in the utility's last general rate case, unless a different return is found to be consistent with the public interest;

(4) provides a current return on construction work in progress, provided that recovery from Minnesota retail customers for the allowance for funds used during construction is not sought through any other mechanism;

(5) allows for recovery of other expenses if shown to promote a least-cost project option or is otherwise in the public interest;

(6) allocates project costs appropriately between wholesale and retail customers;

[2] September 3, 2013 *Order* in Docket No. E002/GR-12-961, Order 23

(7) provides a mechanism for recovery above cost, if necessary to improve the overall economics of the project or projects or is otherwise in the public interest; and

(8) terminates recovery once costs have been fully recovered or have otherwise been reflected in the utility's general rates.

*B. PROJECT ELIGIBILITY*

Xcel's petition only includes projects that were previously approved for recovery in past TCR filings. As such, the Department concludes that all projects included in the initial filing are eligible for cost recovery under Xcel's 2014 TCR Rider.

The Company also requested that the Commission provide Xcel some direction as to the timing of the inclusion of two transmission projects located outside of Minnesota: the Couderay to Osprey transmission line located in Wisconsin and the Big Stone to Brookings transmission line located in South Dakota.

According to Xcel, legislation passed in 2013 allows for the recovery of costs associated with out-of-state projects through the TCR. The Company did not include the costs associated with either of these projects in its 2014 TCR filing "due to the timing of the legislation and our filing preparations."[3] Attachment 4 of the filing includes estimates of the total 2015 and 2016 revenue requirements for both of projects. The Company's estimates are $3.5 million for 2015 and $7.5 million for 2016.

The pertinent language in Minn. Stat. 216B. subd. 7 b (ii) states:

> New transmission facilities approved by the regulatory commission of the state in which the new transmission facilities are to be constructed, to the extent approval is required by the laws of that state, and determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system.

In Department Information Request No. 6, the Department asked Xcel to: "Provide the additional data, including project descriptions, project timelines, and project details for the Couderay to Osprey and Big Stone to Brookings projects. Xcel responded to the Department's information request No. 6 on December 16, 2014. The Company's response is included as [TRADE SECRET] Attachment A.

As an overall threshold question, Xcel should show that 1) the projects are built to serve Minnesota ratepayers in the same manner as other transmission projects and 2) the costs Xcel proposes to charge to Xcel's Minnesota ratepayers are the same as the costs that would be charged in a rate case. In addition, Xcel would need to show that the costs it proposes to charge to ratepayers are reasonable. At a minimum, those steps would be necessary before the Department could recommend inclusion of any of the costs associated with the projects in the 2015 TCR.

[3] Petition at page 8.

However, the Company agreed not to request recovery of the costs associated with these two projects in its most recent general rate proceeding, Docket No. E002/13-868. In that proceeding, Company-witness Jeffrey C. Robinson stated in his Direct Testimony at page 39 that Xcel was proposing to "not add new transmission projects to the TCR Rider during the multi-year rate plan."

Given that the multi-year rate plan covers 2014 and 2015, the Department concludes that Xcel voluntarily committed to not recovering the costs of these two projects, or any other new projects in Mr. Robinson's testimony and that the matter does not merit further discussion at this time. If Xcel seeks to recover costs of these projects in its 2016 TCR, the Company should show that:

1) the projects are built to serve Minnesota ratepayers in the same manner as other transmission projects;
2) the costs Xcel proposes to charge to Xcel's Minnesota ratepayers are the same as the costs that would be charged in a rate case; and
3) the proposed costs are reasonable.

### *C. REASONABLENESS OF PROJECT REVENUE REQUIREMENTS AND COST RECOVERY CAPS*

The Commission's 2010 TCR Order[4] set the standard for evaluation of TCR Project Costs going forward as follows:

> …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 Table 1 of its filing, Xcel showed the cost estimates at the time of initial approval of the eligible projects and the 2014 cost estimate in Table 4 on page 19 of its filing. Additionally provided were the escalated costs in 2014 dollars for the project cost estimates as well as the potential additional escalation expected at the time of project completion. In the 2012 TCR proceeding,[5] the Commission approved an $8.2 million cost escalation (which represented a 2.8 percent annual increase) from 2007 dollars to 2014 dollars through an escalation rate from the Handy Whitman index. Xcel again used the Handy Whitman index to escalate the project cost caps for the La Crosse projects, and proposed the new escalated values in 2014 in addition to projected 2015 values estimated for completion of the projects.

[4] Docket No. E002/M-10-1064
[5] Docket No. E002/M-12-250

**Table 3: Project Cost Estimates ($M)**

| Transmission Project | Initial Cost Estimate 2007 $ | Escalation to 2014 $ (17.78%) | Cost Estimate 2014 $ | Potential Additional Escalation to Completion (1.4% per year) | 2015 Estimated Cost Cap at Completion |
|---|---|---|---|---|---|
| CapX2020 Fargo – Twin Cities | $231.0 | $41.1 | $272.1 | $3.8 | $275.9 |
| CapX2020 Brookings – Twin Cities | $523.9 | $93.1 | $617.0 | $8.6 | $625.6 |
| CapX2020 La Crosse (MN, MISO, and Local) | $276.5 | $49.2 | $325.7 | $4.6 | $330.3 |

The Company illustrates that it is currently on track to meet the original project cost estimates for the CapX2020 Fargo-Twin Cities and Brooking-Twin Cities sections, but would exceed the original project cost estimate for the CapX2020 La Crosse project as shown in Table 4.

**Table 4 – Project Cost Estimates ($M)**

| Transmission Project | Cost Estimate Docket | Initial Cost Estimate | Projected Investment through 2015* | Estimated Project Cost at Completion* |
|---|---|---|---|---|
| CapX2020 Fargo – Twin Cities | CN-06-1115 | $231.0 | $213.9 | $213.9 |
| CapX2020 Brookings – Twin Cities | CN-06-1115 | $523.9 | $459.8 | $462.2 |
| CapX2020 La Crosse (MN, MISO, and Local) | CN-06-1115 | $276.5 | $295.8 | $299.1 |
| Total | | $1,031.4 | $969.5 | $975.2 |

** Includes AFUDC as shown in Attachment 3 of the Company's filing.*

In DOC Information Request No. 8, the Department asked the Company to identify which of the Handy-Whitman indexes the Company used to escalate the project costs for the different transmission projects. Xcel's response is included as Attachment B.

The Company explained in its response that its uses a blend of 39 indices (35 from Handy-Whitman and 4 from Global Insights Producer Price Index forecast) to establish annual escalation factors for the substation and transmission business". Xcel then provided a table that listed the different indices and their origins.

The Department's only question regarding the table involves the developed of the first three Tables is that Xcel explain in its reply comments why it uses indices for "All Regions" instead of the indices for the North Central Region in those tables.

The Department does not dispute the concept of the Company calculating escalated cost caps in order to compare initial cost estimates to the costs of the projects based on the year in which the dollars were spent. The Department will wait to comment on the Company's proposed calculation until after Xcel has responded to the Department's request for additional information in its reply comments.

The information Xcel provided in Table 2 suggests that only one project is estimated to exceed the initial estimate using the Xcel's proposed annual escalation factor. However, the Department also assesses the total costs of the three components of the CapX2020 project and notes that savings with the CapX2020 Fargo-Twin Cities and Brookings-Twin Cities lines appear to be large enough of offset the cost overrun for the Capx2020 La Crosse component. Because these three components were part of a single CN proceeding, the Commission may choose to view these three components as a single project. If so, the Department concludes that Xcel has not exceeded the overall costs of the CapX2020 project from the CN-06-1115 docket.

The Department also asked the Company to provide cost information on a per-mile basis for similarly situated transmission facilities. The Company's TRADE SECRET response in Attachment C suggests that the cost per mile of its various projects is not unusually high.

Given all of this information, the Department concludes that Xcel should be allowed to recover at least $950.2 million in its 2015 TCR for these projects, calculated as the sum of the projected investment for 2015 for the Fargo-Twin Cities and Brookings-Twin Cities segments, plus the initial cost estimate for the La Crosse segment:

- $213.9M + 459.8M + 276.5M = $950.2M

In addition, if the Commission chooses to view the CapX2020 segments as one project from the one CN proceeding, the Commission could allow Xcel to recover the $969.5M amount, to reflect that the cost savings for the Fargo and Brookings segments offset the cost overrun for the La Crosse segment. This is a perspective the Commission may want to monitor in the future.

*D. MISO SCHEDULES 26/26A CHARGES (RECB)*

During the 2008 Minnesota Legislative Session, Minn. Stat. 216B.16, Subd, 7(b) (2) was amended to allow utilities providing transmission service to recover "the charges incurred by a utility that accrue from other transmission owners' regionally planned transmission projects that have been determined by MISO to benefit the utility, as provided for under a federally approved tariff," upon Commission approval. The Statute further requires any recovery to "be reduced or offset by revenues received by the utility and by amounts the utility charges to other regional transmission owners, to the extent those revenues and charges have not been otherwise offset."

As in previous TCR filings, the Company proposed to recover net charges that it pays other electric utilities through MISO Schedules 26/26A in the filing. Xcel proposed to recover the estimated payment amount under MISO Schedules 26/26A net of estimated amount of revenue received from other utilities under these Schedules. Specifically, Xcel proposed to include actual net 2013 MISO Schedules 26/26A revenues of $13,469,507 in its TCR rider in addition to the partial forecast revenues for 2014 and forecast revenues for years 2015 and 2016. Xcel has received, and continues to forecast more MISO Schedules 26/26A revenues than expenses into the future.

*E. FEDERAL ENERGY REGULATORY COMMISSION DOCKET NOS. EL11-66-001 AND EL-14-12-000 AND POTENTIAL IMPACT ON XCEL'S TCR*

Docket No. EL11-66-001 is a complaint filed by various industrial customers and consumer advocates located in the Northeastern United States before the Federal Energy Regulatory Commission (FERC). The complainants requested that the FERC revise its methodology for determining the rate of return on common equity used to establish cost-based rates of public utilities subject to its jurisdiction. FERC issued a decision in this proceeding on June 19, 2014 that adopted a two-step discounted cash flow (DCF) methodology that uses both short-term and long-term growth projections to determine the appropriate ROE for electric transmission owners (TOs). One effect of the adoption of this methodology was to place downward pressure on TO ROE's for all FERC-regulated utilities.

Not long after the FERC's decision in the EL11-66-001 docket, a group of industrial customers in the MISO region filed a similar complaint in docket no. EL14-12-000. The complainants in this proceeding are proposing the reduction in ROE to 9.15 percent. Additionally the complainants are requesting a limitation in the equity capital ratio used in the formula to 50 percent. Subsequently, another intervening group proposed a lower equity to capital ratio of 47 percent.[6]

Xcel is concerned as to the potential financial impact of a reduction in its FERC approved ROE on its shareholders if the FERC issues a ruling in docket no. EL-14-12-000 similar to the one it issued in Docket No. EL11-66-001. If FERC were to approve the application of a methodology for calculating ROE that would lower the MISO TO's ROE, MISO's wholesale rates would decline. A decline in MISO's wholesale rates would result in a decrease in the amount of revenue that Xcel receives from MISO for its use of Xcel's transmission assets. The wellspring for the Company's concern is that FERC-related revenues for its wholesale transmission assets are recovered, or in this case credited, to ratepayers via two different cost recovery mechanisms - base rates, and the TCR Rider.

Xcel is not concerned about the impact of a decrease in revenues related to transmission assets where costs are currently recovered through the TCR. As is the case with all riders, the risk associated with lower revenues than forecasted falls completely on ratepayers; shareholders are unaffected. Rather, Xcel is concerned as to the financial impact of the lower revenues associated with MISO services recovered through base rates.

To illustrate Xcel's concerns, assume Xcel has $100 million in wholesale transmission assets that are currently used by MISO and Xcel's:

- current FERC approved ROE is 12.38 percent;
- its average weighted cost of debt is 4 percent; and,
- its FERC (hypothetical) capital structure is 60 percent equity and 40 percent debt.

[6] The Department of Commerce has joined this complaint via a group of consumer advocates.

Under this set of assumptions, Xcel's FERC average weighted cost of capital is equal to 9.028 percent.[7] Xcel's return on rate base would be equal to $9.028 million. However, if FERC reduces Xcel's FERC ROE to 10.60 percent, with no other change, Xcel's FERC average weighted cost of capital would decline to 7.96 percent[8] and Xcel's return on rate base would decrease by $1.068 million to $7.960 million.

Xcel's concern is that it calculated its rates in its current Multi-Year Rate Plan (Docket No. E002/GR-13-868) for 2015 assuming it would be receiving a FERC ROE of 12.38 percent, which Xcel credited against its forecasted 2015 retail revenue requirement. If the FERC ROE is subsequently decreased, then Xcel is concerned that it would be crediting to retail ratepayers too much for the FERC ROE and Xcel's 2015 rates would not be sufficient to cover its forecasted net revenue requirement for 2015.

A second complicating factor is that if FERC did pursue that approach and if FERC did so retroactively, Xcel's lower rates could be affected from November 2013 onward.

While the issues in the FERC complaint have not been decided, Xcel does not want its shareholders to face any risk of a decision by FERC to decrease the FERC ROE. The Company is proposing to shift that risk in the EL-14-12-000 proceeding from its shareholders to its ratepayers. As Xcel explained in the filing:

> Should FERC order a change in the MISO ROE, the Company believes the appropriate recognition of this change would be to recognize the impact in the TCR Rider by including a true-up for all affected wholesale transmission revenue and expenses, including both the portion included in the TCR Rider *and the portion included in base rates in the pending rate case*[9].
> (Emphasis added)

Xcel provided four reasons for its request:

- The complaint was filed after the Company filed its pending rate case;
- FERC has taken no action while the rate case record is open that would allow the parties to adjust the test year;
- The outcome of the FERC ROE complaint may not be decided until after the Commission issues a final order in the rate case in early 2015; and
- The FERC order could affect the Company's MISO transmission revenues and expenses for all of 2014 for reasons outside the Company's control[10].

The Department issued DOC Information Requests Nos. 1 and 2 to develop additional context for the Company's request. In response to DOC Information Request No. 1, Xcel explained that a worst case scenario of the impact on NSP for 2015 would be a $7.5 million shortfall in base rate revenue. The Company also included a calculation in Attachment B of

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[7] (12.38% x 60%) +(4.0% x 40%) = (7.428%) + (1.6%) = 9.028%
[8] (10.60% x 60%) +(4.0% x 40%) = (6.36%) + (1.6%) = 7.96%
[9] *Ibid* at page 14
[10] *Ibid* at page 15.

its request that estimated the total impact (from November 2013 through December 2015) of such a change to be $15.2 million (which includes the effects of any retroactive effective date by FERC.)

In Information Request No. 2, the Department requested that the Company identify situations where Commission has allowed a utility to recover the change in a base rate revenue requirement through a rider.[11] In response the Company identified two cases:

1. *Docket No. E002/GR-10-971*[12]

The Company noted that, for the Renewable Energy Standard (RES) Rider, the Company used the RES Rider to true-up the recovery of the production tax credit (PTC), for which a level was estimated in base rates. This concept was not discussed explicitly by parties throughout the rate case or by the Commission in its Order.

2. *Docket No. E002/M-13-475*[13]

In the November 7, 2013 Commission Order[14] the Commission approved the use of the RES Rideras the appropriate mechanism to carry out the PTC true-up.

The Department also notes a third docket in which a similar issue was considered:

3. *Docket No. E002/GR-08-1065*

This issue was first raised in the 2008 Xcel rate case where the cost recovery mechanism for the Grand Meadow Wind Farm was considered. In that case, the Company stated its preference for recovery of all costs through the RES Rider due to the large amount of uncertainty related to the production of the generation, and the resulting impact that would have on federal PTCs. The Department proposed moving recovery of the Grand Meadow's costs into the base rates if the Commission trued-up through the RES Rider the difference between the PTC's built into base rates and the actual PTCs.

The Department believes that the past Commission Orders with regard to the PTC are materially different in concept and situation when compared with the Company's current request to allow an *ex post* adjustment to the wholesale transmission revenues through the TCR Rider that are included in the base rates as proposed in this petition.

When considering the base level of costs associated with the production of wind facilities, it is difficult to accurately predict what the actual production will be, especially when, like with the cases listed above, that facility is relatively new and production characteristics are not well known. The Department's recommendation of placing the costs of the wind generation

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[11] Copies of these DOC information requests are included in Attachment D.
[12] *In the Matter of the Application of Northern States Power Company, a Minnesota Corporation, for Authority to Increase Rates for Electric Service in Minnesota.*
[13] *In the Matter of Northern States Power Company d/b/a Xcel Energy for Approval of its 2013 Renewable Energy Standard Rider Adjustment Factor.*
[14] Order Approving Production Tax Credit True-Up – *In the matter of Northern States Power Company d/b/a Xcel Energy for Approval of its 2013 Renewable Energy Standard Rider Adjustment Factor.*

into base rates in the 2008 rate case was driven by the fact that Grand Meadow was in service during the test year and as such, belonged in the base rate. The Department's recommendation however, recognized that there was significant uncertainty about the actual production levels. Additionally in the Docket E002/M-13-475, the RES PTC true-up, the fact was reinforced that the RES was the appropriate medium to true-up fluctuations in actual production from the base rate revenue requirements.

The Department also notes that the proposal in this petition to include a true-up for affected wholesale transmission revenue and expenses through the TCR resulting from the FERC ROE decision fundamentally differs from the current RES/PTC true-up system. First, the PTC true-up included in the RES operates more like the Fuel Clause Adjustment (FCA), which enables regulated gas and electric utilities to adjust rates to reflect changes in the cost of energy delivered to customers from costs authorized by the Commission in the most recent rate case. The PTC true-up in the RES operates similarly to the FCA, as the base rate revenue requirements are based on energy production and the RES allows the true-up of actual costs of the wind generation. In the Company's 2010 rate case, Xcel proposed continuing to use the RES Rider true-up mechanism to true up the recovery of its best estimates of PTCs in base rates due to the uncertainty in the level of production tax credits associated with wind facilities.[15]

However, the Company's proposal to recover the difference in transmission revenues and expenses through the TCR that would result from FERC adjusting the MISO ROE is not a comparable proposition for several reasons. First, the change is not linked to energy production. Instead, it is a potential change to the business climate in which Xcel may operate in the future, and does not represent historical uncertainty and variation, which is the primary reason that PTCs are adjusted through the RES rider currently. Second, allowing Xcel to charge higher rates for a future decision that may or may not be made by FERC is speculative. Although the timing of the FERC ROE announcement with respect to the current rate case for the Company may be unfortunate, it is no different than any other change to the business climate from which base rate revenue requirements are calculated, and does not share the same variable characteristics as the PTC/RES Rider.

As a result of this analysis, the Department recommends that Xcel not be authorized to true-up the portion of wholesale transmission revenue and expenses included in the base rates in the pending rate case through the TCR as Xcel has requested.

### *F. RATE OF RETURN ON INVESTMENT*

The TCR Statute allows for a return on investment at the level approved in the utility's last general rate case, unless a different return is found to be consistent with the public interest. As shown in Attachment 10 of its petition, Xcel proposes to use an overall rate of return of 7.45 percent, which is consistent with the overall rate of return approved by the Commission in Xcel's last electric rate case (Docket No. E002/GR-12-961). The Department does not oppose Xcel's request.

[15] Docket No. E002/M-13-475 – November 7, 2013 Commission Order Approving Production Tax Credit True-Up

## G. ALLOCATION OF COSTS

### 1. Allocation between Wholesale and Retail

In its March 29, 2007 *Order Making Determination of TCR Project Eligibility, 2007 TCR Adjustment Rates, Notice of Annual RCR Compliance Reports* in Docket No. E002/M-06-1505, the Commission ordered Xcel to include a revenue credit in its calculation of revenue requirements for wholesale revenues received under the Company's Open Access Transmission Tariff (OATT). Consistent with its methodology in previous TCR filings, Xcel proposes to estimate the OATT revenue credit as an offset to the forecasted revenue requirement for each project under the TCR Rider. Xcel's OATT calculations are provided in Attachment 11 of its petition. The Department concludes that Xcel's methodology is reasonable.

### 2. Allocation between Northern States Power Company – Minnesota (NSPM) and Northern States Power Company – Wisconsin (NSPW)

To determine its Minnesota jurisdictional revenue requirement, Xcel used a demand allocator, which reflected cost-sharing between NSPM and NSPW pursuant to the FERC-approved Interchange Agreement. Xcel proposed to use its actual interchange allocators for 2014 and budget allocators for 2015. The Department agrees with Xcel's approach and notes that it is consistent with the methodology used in previous TCR filings.

One interesting result of the use of these demand allocation factors is that the Street Lighting classes are no longer allocated any of the TCR's costs. This outcome is due to Xcel's assumption that those classes do not contribute to its summer coincident peak allocation factors. Given that MISO currently sets capacity requirements based on a summer peak, the Department agrees that this result is reasonable at this time. However, if MISO changes its annual construct to a seasonal construct, it may be necessary to revisit this issue.

### 3. Allocation between State Jurisdictions and Minnesota Customer Classes

NSPM costs are further allocated among state jurisdictions (Minnesota, North Dakota, and South Dakota) and Minnesota customer classes based on the type of demand allocation factors approved by the Commission in prior TCR filings. Specifically, Xcel proposes to use the demand allocation factors that were approved for its most recent Rate Case (Docket No. E002/GR-12-961). The Department agrees with this approach, and notes that it is consistent with the methodology used in previous TCR filings.

## H. COMPLIANCE FILING, TRUE-UP REPORT, AND TRACKER BALANCES

Xcel discusses its 2015 TCR Compliance Filing, True-up Report, and Tracker Balance on page 19 of its petition. As explained therein, the Company proposed to increase its 2015 TCR revenue requirements by $8.5 million to reflect the under-recovery of the 2014 revenue requirements. The remaining balance from the 2014 revenue requirements has been included in the 2015 Tracker balance as the Adjustment Factor to recover the 2014 revenue requirements as implemented on September 1, 2014 and calculated to recover costs over ten months. The Department agrees with this approach, and notes that it is consistent with the methodology used in previous TCR filings.

### *I. INTERNAL CAPITALIZED LABOR COSTS*

Xcel removed its internal capitalized labor costs from its 2015 TCR Rider, consistent with the Commission's decisions in past TCR proceedings. According to the information contained in filing, the effect of this adjustment lowered the 2015 TCR revenue requirement by $618,175.

## III. SUMMARY AND RECOMMENDATIONS

The Department recommends that the Commission:

- not allow Xcel to include the revenue requirements associated with the two out-of-state projects it identified in the filing to be recovered in the 2015 TCR. The Department does not oppose additional discussion of these projects;
- allow Xcel to recover at least $950.2 million in its 2015 TCR if the Commission views the three segments of CapX2020 separately. If Commission chooses to view the CapX2020 segments as one project from the one CN proceeding, the Commission should allow Xcel to recover the requested $969.5M; and
- not allow Xcel to recover any changes to revenues collected by MISO and passed on to Xcel associated with wholesale transmission costs and revenues recovered through Xcel's base rates as a result of FERC's actions in Docket No. EL-14-12-000.

The Department also requests that Xcel explain in its reply comments why it uses indices for "All Regions" instead of the indices for the North Central Region in the calculation of the Handy-Whitman escalation factor it uses to escalate the cost estimates from its various certificate of need filings.

The Department will review Xcel's reply comments and indicate whether there are any changes to its overall recommendations regarding Xcel's 2015 TCR Rider.

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|---|---|---|---|
| Xcel Energy | | | |
| Docket No.: | E002/M-14-852 | | |
| Response To: | MN Department of Commerce | Information Request No. | 6 |
| Requestor: | Zac Ruzycki, John Kundert | | |
| Date Received: | December 4, 2014 | | |

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Question:
Reference: Page 9 of the filing

Provide the additional data, including project descriptions, project timelines, and project approval details for the Couderay – Osprey (WI) and Big Stone – Brookings (SD) projects. Please also provide forecasted installed cost per mile in 2014 dollars for these two projects.

Response:

**Big Stone – Brookings 345 kV Line**

***Project Description and Context***

This project consists of the NSP portion of a 75-mile 345 kV transmission line between Big Stone County and Brookings County in eastern South Dakota. This project will serve multiple regional needs, including load-serving, generation outlet, and the improvement of energy market performance. Otter Tail Power will construct and own a portion of the line; NSP will be a participant in this project and other project participants will be determined, however at this time there are no other project participants expected. We have only included in this filing the portion of costs for which Xcel Energy will be responsible, which are:

- Adding protective equipment for a new transmission line;
- Adding line reactors and protective equipment; and
- Constructing an approximately 45 mile double-circuit capable 345 kV line.

***Efforts to Ensure Lowest Cost to Ratepayers***

All major materials (steel structures, switches, transformers, breakers and conductors) and construction labor for this project will take advantage of contracts that have been negotiated by the Company's sourcing group and will utilize self-performed construction labor for the installation of foundations. These contracts were negotiated based on Xcel Energy system-wide use of materials and components resulting in economic benefits to the overall project budget and project schedule.

### *Forecasted Installed Cost per Mile (total costs for both partners)*

For the Big Stone – Brookings project, we have provided the forecasted installed cost per mile of transmission line based on the total project costs of all the Owners which is more representative than separating out Xcel Energy's share or cost percentage.

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**TRADE SECRET ENDS]**

Note: The northern 32 miles of this transmission line will be built to be double circuit capable.

## Couderay –Osprey

### *Project Description and Context*

This project constructs 36 miles of new 161 kV transmission between the Osprey and new Couderay (renamed Radisson) substations located in central northern Wisconsin near the town of Ladysmith. This project is required due to the expansion of industrial load in this region of Wisconsin. The current 69 kV line from Radisson to Osprey will be replaced by a 161/69 kV double circuit. The 161kV line will utilize 795 ACSS conductor and the 69 kV circuit will use 477 ACSS conductor. Additionally a 187 MVA 161/115 kV transformer will be installed at the Osprey substation.

### *Efforts to Ensure Lowest Cost to Ratepayers*

All major materials (steel structures, switches, transformers, breakers and conductors) and construction labor for this project will take advantage of contracts that have been negotiated by the Company's sourcing group. These contracts were negotiated based on Xcel Energy system-wide use of materials and components resulting in lowest cost.

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## *Forecasted Installed Cost per Mile*

**Couderay –Osprey**

**(Couderay [Radison]-Osprey 161kV /69kV Double Circuit)**

| | | |
|---|---|---|
| Miles (161kV/69kV Double Circuit) | 36 | $m/Mile |
| Permitting Costs | 450,518 | 0.01 |
| T-Line | 37,773,828 | 1.05 |
| ROW | 1,500,000 | 0.04 |
| Total Costs (Lines) | 39,724,346 | 1.10 |
| | | |
| Subs & Subs Land | 7,541,783 | |
| Overall Project Costs | 47,266,129 | |

| Project Name | Route Permit Docket No. | Route Permit Filed Date | Route Permit/ CON Order Dates | Design/ Engineering/ Procurement | ROW Acquisition | Construction Start | Projected In-Service | Current Status |
|---|---|---|---|---|---|---|---|---|
| Big Stone – Brookings | EL12-063 (SD) | 12/19/2012 | Facility Permit for 35 miles of planned line issued January 2007 (recertified April 2013) | | | | | Project is in final Planning, Engineering and Preconstruction. |
| | EL13-020 (SD) | 6/3/2013 | Facility Permit for 40 miles of planned line issued February 2014 & August 2014 (alignment modifications) | June 2014 | December 2014 | August 2015 | September 2017 | Project is in final Planning, Engineering and Preconstruction. |
| Couderay – Osprey | 4220-CE-178 (WI) Certificate of Authority | 5/15/2012 | 10/25/2012 | September 2013 | September 2014 | December 2014 | December 2015 | Project is Under Construction. |

| | |
|---|---|
| Preparer: | Christopher Buboltz |
| Title: | Transmission Project Manager I |
| Department: | Xcel Energy Services Project Management North |
| Telephone: | 612-330-1921 |
| Date: | December 16, 2014 |

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|---|---|---|---|
| Xcel Energy | | | |
| Docket No.: | E002/M-14-852 | | |
| Response To: | MN Department of Commerce | Information Request No. | 8 |
| Requestor: | Zac Ruzycki, John Kundert | | |
| Date Received: | December 4, 2014 | | |

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Question:
Reference: Page 18 of the filing

Please identify which Handy-Whitman index the Company used to escalate the project costs for the different transmission projects.

Response:
Xcel Energy uses a blend of 39 indices (35 from Handy-Whitman and 4 from Global Insights Producer Price Index forecast) to establish annual escalation factors for the substation and transmission business.

The Consumer Price Index (CPI), which projecst escalation (or inflation) of costs the average consumer would see, is a more widely-known example of a price escalation index. To project the CPI, the Bureau of Labor Statistics creates a market basket of more than 200 goods and services consumed by the typical residential consumer in order to forecast inflationary costs pressures. Examples of these categories are apparel, transportation, food and beverage.

The CPI doesn not adequately represent goods and services consumed in the construction of transmission lines and substations. Therefore, Xcel Energy created a market basket of 39 items that are components of substation and transmission construction projects. Examples include power transformers, concrete, conductor, fabricated steel, gravel, gasoline, and several wage indices. A complete list of the 39 indices are included as Attachment A to this response. The indices were selected after analysis of 10 completed substation / transmission projects.

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| | |
|---|---|
| Preparer: | Albert Templeton |
| Title: | Associate Energy Trader |
| Department: | Energy Trading |
| Telephone: | 303-571-7728 |
| Date: | December 16, 2014 |

Page 1 of 1

| Table | Index |
|---|---|
| **Handy Whitman Table A1 \| Utility Plant Materials: All Regions** | Switchboards: JBUSB |
| | Power Transformers: JBUTRP |
| | Oil Switches: JBUSO |
| | Standard Cross Arms: JBUASC |
| | Stand. Galv. Steel Guy Wire: JBUWSG |
| | Plastic Conduit: JBUCNP |
| | Power Wire & Control Cable: JBUWP&CBLC |
| | Overhead Conductor-Trans: JBUCNTO |
| | Underground Conductor-Trans: JBUCNTU |
| | Construction Equipment: JBUCEQ |
| **Handy Whitman Table A2 \| Proxied Utility Plant Materials: All Regions** | Communication Equipment: EQUIPCOMM |
| | Fabricated Steel: FABRSTL |
| | Gravel: GRAVEL |
| | Insulators: INSULATORS |
| | Sheet Metal: SHEETMETAL |
| | Steel Plates: STEELPLATES |
| | Steel Poles: STEELPOLE |
| | Steel Shapes: STEELSHAPES |
| | Tower Steel: TOWERSTEEL |
| **Federal Reserve Bank and Producer Price Indexes \| 10-year \| Global Insight Forecast \| All Regions** | Producer Price Index--Refined Petroleum Products |
| | Producer Price Index--Lumber & Wood Products |
| | Producer Price Index--Metals & Metal Products |
| | Producer Price Index--Machinery & Equipment |
| **Table A30 \| Utility Price and Wage Indicators** | Gasoline: PPI3241101 |
| | Heavy Fuel Oils, including No. 5, No.6, heavy diesel, gas enrichment oils: PPI3241105 |
| | Utility Service Workers: CEU4422000006 |
| | Electric Power Generation, Transmission & Distr. Workers: CEU4422110006 |
| | Managers & Administrators: ECIWSPWMGRNS |
| | Professional & Technical Workers: ECIWSPWP&TNS |
| **Handy Whitman Table A5 \| Cost Trends of Building Construction: North Central Region** | Structural Steel Erected: JBCSS@NOC |
| | Reinf. Concrete (Ready-Mix): JBCCRFRM@NOC |
| | Ready-Mix Concrete: JBMCRM@NOC |
| | Steel Bars for Reinf. Conc: JBMCRFSB@NOC |
| | Building Trades Labor: JBLB@NOC |
| | Heavy Constr. Trades Labor: JBLHV@NOC |
| | Labor for Reinf. Conc: JBLCRF@NOC |
| | Common Labor: JBLC@NOC |
| | Electricians: JBLEL@NOC |
| | Pipefitters: JBLPF@NOC |

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Xcel Energy

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|---|---|---|
| Docket No.: | E002/M-14-852 | |
| Response To: | MN Department of Commerce | Information Request No. 9 |
| Requestor: | Zac Ruzycki, John Kundert | |
| Date Received: | December 4, 2014 | |

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Question:

Reference: Attachment 1, Page 2

a. Has the Company completed any analyses that compare the forecasted installed cost per mile of the different CapX2020 projects with similarly situated projects being constructed in other parts of the United States or Canada? If so, please provide this information in your response.

b. Does the Company have access to any analyses developed by other participants in the CapX2020 effort that compare the forecasted installed cost per mile of the different CapX2020 projects with similarly situated projects being constructed in other parts of the United States or Canada? If so, please provide this information in your response.

c. Is the Company aware of any publically available analyses that are related to the questions contained in subparts (a) and (b)? If so, please provide this information in your response.

Response:

a. Yes. Xcel Energy's CapX2020 project staff has completed some research on other utilities' projects using publicly-available information from filings with state utility commissions, regional transmission authorities, and the FERC. Please see the graphs below.

   Please note that the following comparison graphs have been designated as Trade Secret information pursuant to Minnesota Statute § 13.37, subd. 1(b). In particular, the information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use.

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Graph 1 - MISO Project Capital Costs
$/Mile by RTO – All 345 kV T-Line Projects with Cost Data

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

Graph 2 – Ownership of 345 kV T-Line Facilities
by Parent Company – Line Miles

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

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b. No, the Company does not have access to any analyses developed by other participants in the CapX2020 effort that compare the forecasted installed cost per mile of the different CapX2020 projects with similarly situated projects being constructed in other parts of the United States or Canada.

c. No, the Company is not aware of any publically available analyses that are related to the questions contained in subparts a. and b.

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| | |
|---|---|
| Preparer: | Christopher Buboltz |
| Title: | Transmission Project Manager I |
| Department: | Xcel Energy Services Project Management North |
| Telephone: | 612-330-1921 |
| Date: | December 16, 2014 |

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|---|---|---|---|
| Xcel Energy | | | |
| Docket No.: | E002/M-14-852 | | |
| Response To: | Department of Commerce | Information Request No. | 1 |
| Requestor: | Zac Ruzycki, John Kundert | | |
| Date Received: | November 4, 2014 | | |

Question:
Reference: Page 14 of the filing:

"Should the FERC order a change in the MISO ROE, the Company believes the appropriate recognition of this change would be to recognize the impact in the TCR Rider by including the true-up for all affected wholesale transmission revenue and expenses, including both the portion included in the TCR Rider and the portion included in base rates in the pending rate case".

a. Please identify the wholesale transmission revenue and expenses that are included in base rates in the pending rate case, (Docket No. E-002/GR-13-868).

b. Provide an estimate of the financial impact of a decision by FERC to lower MISO's ROE to 9.15 percent from the current 12.38 percent on the wholesale transmission assets identified in subpart (a) on the revenues recovered through Xcel Energy's base rates on an annual basis for 2015.

c. Is it the Company's position that the risk of cost recovery associated with its "appropriate recognition" of a change at FERC of this type for transmission costs recovered in base rates would be symmetrical?

Response:

a. Please reference Attachment A for the transmission revenue and expenses included in base rates in the pending rate case (Docket No. E002/GR-13-868).

b. Please reference Attachment B for an estimate of the financial impact of a FERC decision to lower MISO's ROE to 9.15 percent from the current 12.38 percent. The return on equity of 9.15 percent represents the request by the complainants rather than a final FERC order; the complaint was set for settlement judge procedures with a finding that the current 12.38% MISO regional ROE may no longer be reasonable, but no FERC finding that the proposed 9.15% ROE would be reasonable. As a result, this analysis likely represents a worst-case scenario and could significantly overstate the potential financial impact to the Company.

In addition, the financial impact of a FERC decision is inherently uncertain due to the unknown specifics of the decision, the impact of estimate-to-actual variances in future plant balances, operating results, capital structure, and a number of other variables. Additionally, the partially offsetting reduction in transmission expense would be driven by the impact of the ROE reduction on all other MISO transmission owners, with the ROE reduction impacting each company differently, including the other transmission owners with transmission investments and revenue requirements in the NSP pricing zone (GRE, SMMPA, CMMPA, MMPA, etc.). We note that the FERC order in Docket EL14-12-000 only expressly applies to FERC jurisdictional MISO member transmission owners, so it is uncertain if the ROE used in the transmission formula rates of the non-jurisdictional utilities, including the non-jurisdictional utilities with investments in the NSP pricing zone, would be reduced and/or the effective date of that reduction. Ultimately, the impact of a FERC decision would be calculated and resettled by MISO based on each transmission owner's revised formula rate template.

The estimate reflecting a lower MISO ROE of 9.15 percent from the current 12.38 percent has been calculated using NSP's estimated 2015 forecasted Attachment O. The revisions result in reduced revenue requirements of 14 percent and 17 percent for Attachment O and Attachments GG/MM, respectively. These percentage reductions were then applied to forecasted wholesale transmission revenues and expenses, assuming similar average impact on other MISO transmission owners, including non-jurisdictional utilities. The result is an estimated total company 2015 net impact to NSP of $14.0 million ($10.1 million related to base rates and $3.9 million related to regionally allocated projects). Based on a composite Minnesota jurisdictional allocator of 74.35 percent in 2015, the 2015 net impact to NSP would be $7.5 million related to base rates. If the ROE for non-jurisdictional utilities is not reduced effective on the same date as the jurisdictional MISO utilities, the 2015 net impact to NSP could be higher.

c. Yes, the Company is proposing a symmetrical true up, whereby any changes in the MISO ROE compared to what is assumed in base rates, plus or minus, will be trued up."

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| | | |
|---|---|---|
| Preparer: | Andrew Sudbury | James P. Johnson |
| Title: | Senior Rate Analyst | Assistant General Counsel |
| Department: | Revenue Requirements North | Legal Services |
| Telephone: | 612-337-2066 | 612-215-4592 |
| Date: | November 17, 2014 | |

**Northern States Power Company**
**2014 Transmission Revenues & Expenses (Docket No. E002/GR-13-868)**
**Transmission Revenue Summary**



| BU | Description | Total Company (Fiscal 2014) | MN Jurisdiction (Fiscal 2014) | Net of Interchange (Fiscal 2014) | Rider Removal Adj (WP A-27) | Amt in Base Rates |
|---|---|---|---|---|---|---|
| | | | 87.67% | 84.79% | | |
| MISO | | | | | | |
| | PTP - Firm | $8,688,233 | $7,617,226 | $6,458,821 | | $6,458,821 |
| | PTP - Non Firm | $758,682 | $665,159 | $564,003 | | $564,003 |
| | Network | $19,697,640 | $17,269,492 | $14,643,200 | | $14,643,200 |
| | Sch 1 - Sch, Sys Ctrl & D | $896,679 | $786,145 | $666,590 | | $666,590 |
| | Sch 2 - Reactive Supply | $8,902,392 | $7,804,985 | $6,618,026 | | $6,618,026 |
| | Sch 24 - Bal Auth | $1,746,037 | $1,530,801 | $1,298,001 | | $1,298,001 |
| | Other RTO GFA Revenue | $134,889 | $118,261 | $100,276 | | $100,276 |
| | MISO Schedule 26 - Trans Expansion Plan | $62,680,586 | $54,953,887 | $46,596,665 | (46,596,665) | $0 |
| | MISO Schedule 26-A MVP | $53,350,442 | $46,773,879 | $39,660,648 | (39,660,648) | $0 |
| JPZ | | | | | | |
| | Joint Pricing Zone - GRE | $31,986,849 | $28,043,798 | $23,778,981 | | $23,778,981 |
| | Joint Pricing Zone - SMMPA | $5,790,884 | $5,077,036 | $4,304,934 | | $4,304,934 |
| | Sch 2 - Reactive Supply | $126,983 | $111,330 | $94,399 | | $94,399 |
| GFA's - TM1 | | | | | | |
| | Network - GFA | $9,697,117 | $8,501,744 | $7,208,824 | | $7,208,824 |
| | Sch 1-Sch, Sys Ctrl & D - GFA | $213,071 | $186,805 | $158,397 | | $158,397 |
| | Sch 2 - Reactive Supply - GFA | $135,646 | $118,925 | $100,839 | | $100,839 |
| | Sch 10 - MISO Passthrough | $305,800 | $268,104 | $227,331 | | $227,331 |
| MISO Tariff | | | | | | |
| | Facilities | $46,866 | $41,089 | $34,840 | | $29,542 |
| GFA's - Fixed Contracts | | | | | | |
| | Facilities | $185,827 | $162,920 | $138,143 | | $117,135 |
| | Contracts - WPPI | $37,440 | $32,825 | $27,833 | | $23,600 |
| | Contracts - UPA | $8,040,000 | $7,048,901 | $5,976,925 | | $5,067,972 |
| | Contracts - UND | $56,816 | $49,812 | $42,237 | | $35,814 |
| | Contracts - Granite Falls | $15,223 | $13,346 | $11,316 | | $9,595 |
| | Contracts - EGF | $46,268 | $40,565 | $34,396 | | $29,165 |
| | GRE Cr Lk Facilities | $212,410 | $186,226 | $157,906 | | $133,892 |
| | GRE 500kV tsmn O&M | $37,801 | $33,141 | $28,101 | | $23,827 |
| | Marshall TOPS Agreement | $99,284 | $87,045 | $73,808 | | $62,584 |
| | Total NSP | **$213,889,863** | **$187,523,446** | **$159,005,443** | | **$71,755,748** |
| Other Revenue | | | | | | |
| | Facilities - Shakopee Dist, Blue Lake | $111,861 | $111,861 | $94,850 | | $80,425 |
| | Distrib FacFxd Ch - Anoka | $63,000 | $63,000 | $53,419 | | $45,295 |
| | Distrib FacFxd Ch - Arlington | $12,237 | $12,237 | $10,376 | | $8,798 |
| | Distrib FacFxd Ch - MN Valley | $1,560 | $1,560 | $1,323 | | $1,122 |
| | Distrib FacFxd Ch - EGF | $21,230 | $21,230 | $18,002 | | $15,264 |
| | Distrib FacFxd Ch - Winthrop | $16,496 | $16,496 | $13,987 | | $11,860 |
| | Distrib Wheeling Ch - Twin Cities Hydro | $354,816 | $354,816 | $300,857 | | $255,104 |
| | Total Other Revenue | **$581,200** | **$581,200** | **$492,814** | | **$417,868** |
| | Grand Total | **$214,471,064** | **$188,104,646** | **$159,498,257** | | **$72,173,616** |

**Northern States Power Company**
**2014 Transmission Revenues & Expenses (Docket No. E002/GR-13-868)**
**Transmission Expense Summary**



| BU | Description | Fiscal 2014 Total Company | MN Jurisdiction | Net of Interchange | Rider Removal Adj (WP A-27) | Amt in Base Rates |
|---|---|---|---|---|---|---|
| | | 87.67% | 84.79% | | | |
| MISO | | | | | | |
| | Sch 1 - Sch, Sys Ctrl & Disp | $641,534 | $562,452 | $476,916 | | $476,916 |
| | Sch 2 - Reactive Supply | $9,486,540 | $8,317,125 | $7,052,282 | | $7,052,282 |
| | PTP | $65,360 | $57,303 | $48,589 | | $48,589 |
| | Network | $10,730,228 | $9,407,502 | $7,976,837 | | $7,976,837 |
| | Admin Charges | $3,024,194 | $2,651,399 | $2,248,182 | | $2,248,182 |
| | Admin Charges | $101,682 | $89,148 | $75,591 | | $75,591 |
| | Admin Charges - FERC 561.4 | $6,094,634 | $5,343,343 | $4,530,743 | | $4,530,743 |
| | Admin Charges - FERC 561.8 | $438,220 | $384,201 | $325,773 | | $325,773 |
| | Admin Charges - FERC 575.7 | $208,997 | $183,234 | $155,368 | | $155,368 |
| | Admin Charges - FERC 561.4 | $214,482 | $188,043 | $159,446 | | $159,446 |
| | Admin Charges - FERC 561.8 | $15,422 | $13,521 | $11,465 | | $11,465 |
| | Admin Charges - FERC 575.7 | $7,355 | $6,448 | $5,467 | | $5,467 |
| | MISO Schedule 26 - Trans Expansion Plan | $66,290,656 | $58,118,941 | $49,280,386 | ($49,280,386) | $0 |
| | MISO Schedule 26-A MVP | $16,299,096 | $14,289,890 | $12,116,726 | ($12,116,726) | $0 |
| JPZ | | | | | | |
| | Joint Pricing Zone Exp - GRE | $28,755,270 | $25,210,579 | $21,376,630 | | $21,376,630 |
| | Joint Pricing Zone Exp - SMMPA | $13,006,471 | $11,403,150 | $9,668,993 | | $9,668,993 |
| | Joint Pricing Zone Exp - CMMPA | $553,467 | $485,241 | $411,447 | | $411,447 |
| | Joint Pricing Zone Exp - NWEC | $518,875 | $454,913 | $385,731 | | $385,731 |
| | Joint Pricing Zone Exp - MMPA | $138,367 | $121,310 | $102,862 | | $102,862 |
| Other | | | | | | |
| | Non RTO Trans | $503,229 | $441,195 | $374,099 | | $374,099 |
| | Non RTO Trans - WAPA | $6,692,940 | $5,867,895 | $4,975,523 | | $4,975,523 |
| | System Studies | $63,165 | $55,378 | $46,956 | | $46,956 |
| | Interconnection Upgrades | $92,964 | $81,504 | $69,109 | | $69,109 |
| | Facility Credit Payments | $650,000 | $569,874 | $483,209 | | $483,209 |
| | Total Transmission Expense | $164,593,149 | $144,303,589 | $122,358,332 | | $60,961,218 |
| Energy Markets Admin Costs (Schedule 10, 16, 17, 24 - includes Wholesale portion) | | | | | | |
| | Schedule 16 & 17 | $7,129,549 | $6,250,682 | $5,300,097 | | $5,300,097 |
| | Schedule 24 | $1,291,613 | $1,132,395 | $960,184 | | $960,184 |
| | Wholesale Schedules 17 & 24 | $123,480 | $108,258 | $91,794 | | $91,794 |
| | Total Energy Markets Admin Costs | $8,544,642 | $7,491,335 | $6,352,075 | | $6,352,075 |
| | Grand Total | $173,137,791 | $151,794,924 | $128,710,407 | | $67,313,293 |

**Northern States Power Company**
**Estimated impact of reduction in MISO ROE from 12.38% to 9.15%**
**Nov-2013 through Dec-2015**
**($000)**



| | 2013 Total Nov-Dec 2013 | 2014 Total 2014 | 2015 Total 2015 | Grand Total |
|---|---|---|---|---|
| Reduction in NSP transmission revenue, net of expense | $ (1,580) | $ (12,550) | $ (14,019) | $ (28,149) |
| Less: MISO Schedule 26/26A portion | 427 | 3,331 | 3,916 | 7,675 |
| Net impact (base rate items) | $ (1,153) | $ (9,219) | $ (10,102) | $ (20,474) |
| | | | | |
| MN 12-month CP demand (Electric Demand) | 87.92% | 87.92% | 87.92% | |
| NSPM 36-month CP demand (Interchange Electric) | 84.88% | 84.79% | 84.56% | |
| Composite Jurisdictional Allocator | 74.62% | 74.55% | 74.35% | |
| | | | | |
| MN Jurisdiction - Base Rate Items | (860) | (6,872) | (7,511) | (15,243) |
| MN Jurisdiction - MISO Schedule 26/26A Portion | (319) | (2,483) | (2,912) | (5,714) |
| Reduction in NSP trans. rev net of exp, MN Jur Tot | (1,179) | (9,356) | (10,422) | (20,957) |

* Transmission revenue and expense based on actuals through Oct-2014, Nov-Dec 2014 forecast, and the 2015 budget last updated July 2014.

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|---|---|---|---|
| Xcel Energy | | | |
| Docket No.: | E002/M-14-852 | | |
| Response To: | Department of Commerce | Information Request No. | 2 |
| Requestor: | Zac Ruzycki, John Kundert | | |
| Date Received: | November 4, 2014 | | |

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Question:

Reference: Page 15 of the filing: The Company references Minn. Stat. §216B.16, subd. 7(b) as the statute that provides cost recovery for net transmission charges under the MISO tariff, if the Commission agrees.

a. Please identify any and all proceedings before the Commission in which the Commission has allowed a utility to recover through a rider costs associated with a change to a base rate revenue requirement that was used to determine rates after rates were approved.

b. Please identify any and all proceedings before the Commission in which the Commission has allowed a utility to recover costs through a rider associated with a change in a base rate revenue requirement in a pending rate case.

c. Has Xcel Energy identified any other statutory language or Commission rules or Orders that support its proposal to recover potential changes in costs/revenues current designated as being recovered through base rates in Docket No. E002/GR-13-868 through the TCR Rider?

Response:

a. It the Commission's November 7, 2013 Order in our RES Rider Adjustment docket, *In the Matter of Northern States Power Company d/b/a Xcel Energy for Approval of its 2013 Renewable Energy Standard Rider Adjustment Factor*, Docket No. E002/M-13-475, the Commission approved the Company's request for a true-up of the base rate Production Tax Credit. During the Company's 2010 rate case (Docket No. E002/GR-10-971), the Company proposed to continue to use the RES Rider true-up mechanism to true-up the recovery of it best estimates of PTCs in base rates. However, neither the parties, nor the

Commission in its order, specifically discussed the status of a PTC true-up after completion of the rate case. The Company then requested the true-up in the RES Rider Adjustment docket, which the Commission approved in Docket No. E002/M-13-475. In its RES Rider Adjustment Docket Order, the Commission stated "[T]he Renewable Energy Standard rider is the appropriate mechanism to carry out the Production Tax credit true-up."[1]

The Company also notes that the Fuel Clause Adjustment and Purchase Gas Adjustment both allow utilities to track changes in actual costs from base rate test year levels. Both fuel and gas costs were historically (prior to the 1970s) considered a base rate cost. Today, a base cost is established each rate case, and then changes from the base cost are tracked to prevent over- or under-recovery, both during the test year and until the next rate case.

This response is provided based on the limited research the Company could perform in the ten day period for this response. The Company cannot say that these examples reflect "any and all proceedings" that may have occurred before the Commission since it was created in the mid-1970s. The noted mechanisms, however, are three examples where the Commission has allowed tracker adjustment to base rate costs.

b. Yes. It is standard ratemaking practice for electric and gas utilities to file a base cost of energy or base cost of gas as part of an initial general rate case filing. The base cost reflects the estimated costs to be incurred during the test year. Utilities then reflect the actual (or more updated forecast of) costs in their FCA or PGA factors in and billed effect during that same test year, subject to true-up.

   The Company also notes that the adjustment to the TCR Rider for any change from the 2014 test year MISO revenues/costs would be reflected in the TCR Rider rates in effect in 2015. So the adjustment would occur after the end of the 2014 test year, similar to the PTC true-up discussed in part (a).

   This response is provided based on the limited research the Company could perform in the ten day period for this response. The Company cannot say whether a comprehensive review of "any and all proceedings" decided by the Commission since it was created in the mid-1970s would identify additional examples.

[1] Order at p. 5.

c. As discussed in our Petition, the Company's position is that Minn. Stat. § 216B.16, subd. 7(b), which allows the Commission to provide TCR Rider recovery of net transmission charges (expenses offset by revenues received and amounts charged to other regional transmission owners) under the MISO Tariff, is consistent with our proposed adjustment to the TCR Rider. See also response to part (a) of this response.

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Title: Assistant General Counsel
Department: Legal Services
Telephone: 612-215-4592
Date: November 17, 2014

# CERTIFICATE OF SERVICE

I Marcella Emeott, 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
Response Comments

Docket No. E002/M-14-852
Dated this 2nd day of January 2015

/s/Marcella Emeott

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