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October 1, 2015

--Via Electronic Filing--

Darrell Nitschke, Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

RE: 2016 TRANSMISSION COST RECOVERY RATE ADJUSTMENT APPLICATION
CASE NO. PU-15-_____

Dear Mr. Nitschke:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed original and seven copies of the 2016 Transmission Cost Recovery (TCR) Application to the North Dakota Public Service Commission for approval of project eligibility and the TCR rate factor.

Also enclosed is a check in the amount of \$10,000 for the filing fee.

An electronic copy of this filing is also being sent to you for your convenience.

Please contact me if you have any questions or comments.

Sincerely,

A handwritten signature in blue ink that reads 'David H. Sederquist'.

DAVID H. SEDERQUIST
SR. CONSULTANT, REGULATION/FINANCE

c: Mike Diller

Enclosures

**BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION
STATE OF NORTH DAKOTA**

IN THE MATTER OF THE APPLICATION OF
NORTHERN STATES POWER COMPANY
FOR APPROVAL OF 2016 TRANSMISSION
COST RECOVERY PROJECT ELIGIBILITY
AND ASSOCIATED RATE

CASE NO. PU-15-____

Application of Northern States Power Company

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the North Dakota Public Service Commission this application for approval of a Transmission Cost Recovery (TCR) Rider rate designed to recover the 2016 revenue requirements for the Company's eligible transmission projects. We submit this application pursuant to N.D.C.C. § 49-05-04.3, which authorizes the Commission to approve a tariff mechanism for the automatic annual adjustment of charges for a public utility to recover the North Dakota jurisdictional portion of eligible investments and expenses related to new or modified transmission facilities. Electric transmission facilities covered by the above-referenced Century Code include associated facilities such as substations and transformers.

In this filing we propose to set a TCR rate to recover the specific 2016 costs related to qualifying projects and expenditures. Specifically, this Application seeks Commission approval of:

- TCR tracker account activity for 2014 and 2015, including actual revenues and expenses and the resulting true-ups;
- Project eligibility of 10 additional transmission projects;
- 2016 TCR revenue requirements of \$5.4 million;
- TCR Adjustment Factor of \$0.002332 to be implemented on January 1, 2016;
- Updated TCR Tracker Report for approved transmission project investments;
- Proposed revisions to the TCR Rider tariff sheet; and
- Proposed customer notice.

We propose to recover the North Dakota jurisdictional portion of costs related to 35 transmission projects located throughout our service territory and our net expenses from the MISO Schedule 26/26A Regional Expansion Criteria and Benefits (RECB) billings. The 2016 revenue requirements to be collected from the North Dakota

jurisdiction are approximately \$5.4 million. Twenty-five projects have previously been approved by the Commission for inclusion in the TCR Rider, and we propose to include an additional 10 projects.

We have calculated the resulting TCR rate of \$0.002332 per kWh to be applied to all energy billed to each customer class during the period beginning January 1, 2016 based on the revenue requirements for 2016. The rate has been calculated to be in place through the end of 2016, and includes the 2014 and 2015 tracker true-ups. The average bill impact would be \$1.75 per month for a typical residential electric customer using 750 kWh, which is a decrease of \$0.13 over the current TCR rate. The rate has decreased because the current rate included both 2014 and 2015 revenue requirements.

I. GENERAL INFORMATION

Pursuant to § 69-02-02-04 of the Commission's Rules of Practice and Procedure, the following information is provided:

A. Name, address, and telephone number of the utility making the filing

Northern States Power Company
2302 Great Northern Drive
PO Box 2747
Fargo, ND 58108-2747
(701) 241-8632

B. Name, address, and telephone number of the attorney for Northern States Power Company

Alison Archer
Assistant General Counsel
Xcel Energy Services Inc.
414 Nicollet Mall – 5th Floor
Minneapolis, MN 55401
(612) 215-4662

C. Title of utility employee responsible for filing

David H. Sederquist
Sr. Regulatory and Financial Consultant
2302 Great Northern Drive
PO Box 2747
Fargo, ND 58108-2747

II. BACKGROUND

A. Statutory Authority and Compliance

The following section of the North Dakota Century Code establishes Commission authority for utilities to recover such investments through a rider mechanism.

49-05-04.3. Rate adjustment - Transmission facility costs.

1. *The commission may approve, reject, or modify a tariff filed under section 49-05-06 which provides for an adjustment of rates to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. For purposes of this section, an electric transmission facility includes an electric transmission line as defined in chapter 49-21.1 and other transmission line equipment, including substations, transformers, and other equipment constructed to improve the power delivery capability or reliability of the electric transmission system; and operating costs include federally regulated costs charged to or incurred by the public utility to increase regional transmission capacity or reliability. The tariff must:*
 - a. *Allow the public utility to recover on a timely basis its investment and associated costs for new or modified electric transmission facilities not reflected in the utility's general rate schedule;*
 - b. *Allow a return on the public utility's investment made for new or modified electric transmission facilities at the level approved in the utility's most recent general rate case;*
 - c. *Provide a current return on construction work in progress for new or modified electric transmission facilities, provided the cost recovery from retail customers of the allowance for funds used during construction is not sought through any other means; and*
 - d. *Terminate cost recovery after the public utility's costs for new or modified electric transmission facilities have been recovered fully or have been reflected in the utility's general rate tariffs.*

The Century Code 49-05-04.3 Subd 2 requires certain information be provided in support of our request for the TCR rate, Table 1 below indicates where this information can be found in this application.

Table 1: Filing Requirements

Requirement	Location in Filing
<p>a. A description and quantification of the costs incurred by the public utility for new or modified electric transmission facilities which are subject to recovery.</p>	<p>Attachment 1- Descriptions of each project proposed to be included in the TCR.</p> <p>Attachment 14- Forecasted costs for each project.</p> <p>Attachment 3- Provides the capital expenditure forecast for each project included in the TCR. (Actual capital expenditures are shown through July 2015 and forecasted capital expenditures are reported for August 2015 through 2017. The revenue requirements shown in Attachment 14 are based on the capital expenditures referenced in Attachment 3.)</p>
<p>b. A schedule for implementation of the applicable transmission facility project.</p>	<p>Attachment 2- Provides information about Commission approvals and a project construction timeline for each of the projects included in our TCR rate request.</p>
<p>c. Calculations to establish that the rate adjustment is consistent with the terms of the tariff.</p>	<p>Attachment 9- Contains the calculation of the proposed 2016 TCR rate factor, consistent with the terms of the TCR tariff.</p> <p>Attachment 15- Contains the tariff page with the proposed rate of \$0.002332 per kWh.</p>
<p>d. An application fee in the amount of one hundred thousand dollars. Upon request of the commission and with the approval of the emergency commission, the applicant shall pay such additional fees as are reasonably necessary for completion of the application process by the commission. The commission may waive or reduce the fee.</p>	<p>We respectfully request a reduced filing fee of \$10,000 consistent with Commission action in our last TCR proceeding, Case No. PU-14-644. We have included a filing fee of \$10,000 with this application, and will pay additional fees as the Commission determines necessary.</p>

B. History

In Case No. PU-12-813, the Company established a TCR Rider tariff as authorized by the above section of the N.D.C.C. The tariff was approved by the Commission in its February 26, 2014 *Order Adopting Settlement* and the associated April 23, 2014 *Motion Approving Compliance Tariffs*. The Commission approved the Company’s 2014 Application to recover the 2014 and 2015 revenue requirements of TCR-eligible

transmission projects that were not currently included in base rates.¹ The present rate of \$0.002505 was implemented on January 1, 2015.

The Company continues to make significant investments in new transmission facilities in order to maintain and improve system reliability and increase power delivery from North Dakota, South Dakota, and western Minnesota. To recover the North Dakota jurisdictional portion of these investments, we propose a TCR rate to be in place January 1, 2016 through December 31, 2016.

III. COSTS TO BE RECOVERED

We propose two types of costs to be recovered through the TCR rider:

1. North Dakota's retail share of revenue requirements for qualifying transmission facilities not currently being recovered in base rates, and
2. Midcontinent Independent System Operator (MISO) Schedule 26/26A costs allocated to North Dakota retail customers.

We provide more detail on both of these costs below.

A. New or Modified Transmission Projects Not Currently in Base Rates

The following CapX2020 Group 1 projects were granted an Advance Determination of Prudence (ADP) by the Commission in Case No. PU-09-678, but are not yet entirely included in base rates:

- CapX2020 Brookings – Twins Cities
- CapX2020 Fargo – Twin Cities
- CapX2020 La Crosse - Local
- CapX2020 La Crosse - MISO
- CapX2020 La Crosse - WI

For certain CapX2020 projects listed above, a portion of the project was in service during the 2013 test year and was included in our base rate request.² For those projects, in order to ensure we do not double recover our costs, we have reduced our request for recovery through the TCR Rider by the portion included in base rates.

¹ Case No. PU-14-644, Commission Motion passed on December 17, 2014.

² The Company proposed to establish a TCR mechanism in Case No. PU-12-813, but the proposed initial rate was \$0.00. We therefore included CapX2020 project costs in base rates even though those projects could in the future be included in a TCR Rider. *See* Late-filed Exhibit Q in the rate case proceeding for more information.

The reduction in our request is shown on our summary of the calculation of revenue requirements on Attachment 4.

The following 20 projects were originally proposed for recovery through the TCR Rider in our last electric rate case (Case No. PU-12-813, Exhibit Q) and were subsequently approved for recovery in our last TCR petition (Case No. PU-14-644). Each of the projects is explained in more detail in Attachment 1.

- | | |
|-----------------------------------|--|
| 1. Sioux Falls Northern | 11. Wilson Substation Conversion |
| 2. Chaska – Hwy 212 Conversion | 12. Kohlman Lake – Goose Lake |
| 3. Minn Valley | 13. Prairie Sub Expansion |
| 4. Maple River – Red River | 14. Black Dog – Savage |
| 5. Big Stone – Brookings | 15. Chisago 2 nd Transformer Addition |
| 6. Lake Marion – Burnsville | 16. Franklin Transformer |
| 7. Maple Lake – Annandale | 17. Cass County Sub Expansion |
| 8. Glencoe – Waconia | 18. New Prague Area |
| 9. Bluff Creek – Westgate | 19. End of Life Replacement – Breakers |
| 10. Scott County 345 kV Expansion | 20. End of Life Replacement – Relay |

The following 10 projects are new or modified transmission facilities that improve the power delivery capability or reliability of the electric transmission system and are not included in base rates. Thus they qualify for TCR Rider recovery as per statute, subject to Commission review and approval. Generally, these projects do not meet the threshold (as defined by the settlement approved in Case No. PU-10-657) for requiring an ADP from the Commission.

1. Dean Lake Substation
2. *End of Life Replacement (ELR) – Transformers
3. Galloping Mitigation Project (NSM 0953)
4. Gleason Lake Substation
5. Maple River
6. Minot Load Serving
7. *Transmission Line Relocation (NSP Reloc)
8. NSPM Major Line Rebuild
9. *Storm and Emergency (S&E) – NSP Line
10. *Yankee Reactor

The asterisks above note projects that were in our construction queue at the time we negotiated our rate case settlement, but which we chose not to include in the 2014-2015 TCR Rider request for various reasons. In general, because last year's filing was our initial TCR Rider request, we limited our request to projects included in Case No.

PU-12-813, Exhibit Q. In addition, three of these projects (the NSP Reloc, the S&E – NSP Line, and the Yankee Reactor projects) are broad form programs that include a variety of system improvements and have now reached a point that their costs are significant, so we have now included the projects in our 2016 TCR request.

B. Efforts to Ensure Lowest Cost to Ratepayers

We have made every effort to minimize the impact of our transmission investment on rates by ensuring these TCR-eligible projects reflect the most effective electrical solution at the lowest cost option for our customers. First, our transmission planners analyze multiple project alternatives for a given transmission project. Each alternative is evaluated based on each option's ability to meet the identified electrical needs for the system and select the option that considers 1) the incremental impact of the project for future needs in the area and 2) best meets the long-term electrical needs of the area in a cost-effective manner. Second, where possible, we have competitively bid equipment procurement and to the extent internal resources are unavailable, we have also competitively bid the engineering, and construction services for the projects included in this application.

Transmission has developed a set of policies and procedures to establish and manage our capital project portfolio. The purpose of these policies and procedures is to define how capital projects are identified, estimated, approved, executed, monitored and controlled, and changed as they move from origination to completion. These policies also help to ensure that we manage and time our capital investments appropriately to address the reliability of our system while keeping the overall costs of all our investments reasonably level over time.

Each project included in our TCR Rider request has a multidisciplinary project team that developed the project's detailed preliminary scope and schedule. These project team members have functional skills including financial management, project management, design & engineering, system operations, construction, siting & land right, scheduling, and vegetation management and planning. Often multiple scope and cost alternatives are developed, estimated and evaluated against each other based on the incremental impact of the project for future needs of the system and best meets the long-term electrical needs of the system at the most cost-effective price.

Our project estimates are based on historical experience and include assumptions made for identified possible risks that may be encountered during the execution of the project, for example sub-optimal soil conditions in the area of the project, permitting, land and right-of-way acquisition, outage constraints, weather conditions, labor

availability, and many more variables are weighed and considered when initially estimating our projects.

Once a project has been estimated and subsequently included in our budget for execution, their estimates are further engineered and risk assumptions are refined and either eliminated or quantified in order to develop their earned value and forecasted cost impacts.

After a project is included in our budget it is reviewed on a monthly basis to compare the monthly budget to actual funds spent. We perform a monthly project forecasting exercise to ensure we have a steady and dependable flow of financial information regarding capital expenditures through completion. Through this process, every project is reviewed and consolidated with all of the other projects in our Transmission project portfolio each month. Project variances are immediately addressed to ensure the costs are prudent, and in line with its vetted estimate.

The Transmission business unit is expected to manage these projects to their established estimates once they been thoroughly developed and fully vetted to ensure that projects included in this petition provide enhanced reliability to our Transmission system and the associated costs are reasonable for our customers.

C. MISO RECB Charges (MISO Schedule 26 and 26A)

The second component of costs included for TCR recovery are costs associated with RECB designated transmission projects. Xcel Energy incurs charges from MISO to pay for a portion of transmission investments made by other electric utilities pursuant to Attachment FF of the MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff. Attachment FF specifies the cost allocation procedures for new transmission projects within the MISO footprint.

Projects subject to RECB cost allocation are identified and selected through the MISO Transmission Expansion Plan (MTEP) process. Allocation and cost recovery methods for RECB projects are specified in detail in Attachment FF, Attachment GG, MM, Schedule 26, and Schedule 26A of the MISO Tariff. MISO's annual MTEP review process identifies those transmission projects that will be included in Appendix A to the MTEP and the appropriate cost-sharing mechanism is identified for each project. Forecasted 2014 and 2015 RECB revenue requirements are shown in Attachment 13.

D. All-In Method of Rate Calculation

As discussed in our rate case testimony, we calculated the TCR rate using the “All-In Method,” which assigns all of the Company’s transmission investments to retail jurisdiction. Under this method, a traditional retail revenue requirement is calculated on the entire investment, both the amount associated with the provision of retail service *and* the amount regionally allocated to other utilities. The Company’s retail rate of return is applied to 100 percent of the investment (treating it all as retail rate base) and 100 percent of the operating costs and investment-related expenses are treated as retail costs.

In addition, 100 percent of the revenues the Company receives from MISO under Schedules 26 or 26A are treated as retail revenue credits that reduce the retail revenue requirement. The All-In Method treats all of the Company’s transmission investments and MISO revenues as retail even though a portion of the investment is used for providing wholesale service under the MISO Tariff.

E. Impact on TCR Rider of Pending FERC Complaint

A group of industrial customers in the MISO region filed a complaint asking the FERC to reduce the 12.38 percent return on equity (ROE) used in the transmission formula rates of jurisdictional MISO transmission owners, including the NSP Companies, to 9.15 percent. The complaint also asked FERC to limit the equity capital ratio used in the MISO formula to 50 percent, unless an individual transmission owner can justify a higher equity ratio. The Company is not proposing an adjustment to the TCR Tracker balance at this time because the issue is still pending. However, we provide the following details about the complaint and further related developments occurring at the FERC.

The FERC has denied the portions of the complaint related to equity capital structures and ROE incentive adders but has initiated hearing procedures regarding the appropriate ROE to be used in the MISO TOs formula rates and has established a November 12, 2013 refund effective date. Hearings were held in August 2015, an administrative law judge (ALJ) initial decision is expected to be issued by November 2015, and a FERC order is expected to be issued no earlier than 2016.

A second complaint was filed in February 2015 by an intervenor in the original ROE complaint. The second complaint proposed to reduce the MISO region ROE to 8.67 percent, prior to any 50 basis point RTO adder. The FERC established a February 12, 2015 refund effective date. An ALJ initial decision is expected in June 2016 with a FERC decision in late 2016 or in 2017. The FERC decision would continue the ROE

refund obligation initiated under the November 2013 complaint through May 2016. The MISO TOs have subsequently sought rehearing of the FERC decision to allow back-to-back complaints involving the same issue with consecutive refund periods, arguing this ruling is contrary to the governing statute. FERC action on the rehearing request is pending.

Until the FERC issues its order in the ROE complaint dockets, the outcome of the cases is uncertain, and we continue to base our assumptions on the previously authorized rate of 12.38 percent. We will continue to keep the Commission updated on the status of these dockets will make a proposal to address the outcome once all of the uncertainties have been resolved.

F. Accumulated Deferred Income Taxes

The Company is assessing its calculation of the plant related Accumulated Deferred Income Taxes offset to rate base to assure it is calculated in accordance with the proration formula in IRS regulation section 1.167(1)-1(h)(6). No estimates of the potential impact, if any, to the 2016 estimated annual revenue requirements are known at this time.

IV. ALLOCATIONS, RATE DESIGN AND ACCOUNTING

A. 2016 TCR Rider Revenue Requirements

The detailed 2016 revenue requirements in support of the proposed TCR rate factor are set forth in Attachment 9.

The Company's TCR revenue requirement model includes a current return on capital expenditures beginning with the cumulative CWIP balance for each project at an established eligibility date, or the date construction expenditures begin, whichever is later. We set the eligibility date of January 1, 2014 for the twenty-five projects included in our 2014-2015 revenue requirements to coincide with the conclusion of the last rate case. Though some of the newly added projects expended construction funds during 2015, we set the eligibility date of January 1, 2016 for the projects in our 2016 TCR Rider request, calculating 2016 revenue requirements beginning with the January 1, 2016 cumulative CWIP balance. The beginning CWIP balance includes Allowance for Funds Used During Construction (AFUDC) incurred prior to the project eligibility date (pre-eligibility AFUDC). After that date, AFUDC is excluded from the CWIP balance. As a result, for each project, a current return is calculated on the North Dakota jurisdictional portion of the CWIP balance which includes only pre-eligibility AFUDC and accumulated capital expenditures.

Project costs are allocated to the North Dakota retail jurisdiction based on the 12 CP demand allocator. In addition, to ensure there is no double recovery from Open Access Transmission Tariff (OATT) revenue collected from non-NSP native load customers, the Company will apply an OATT revenue credit calculated based on a forecast of OATT revenue collections divided by the transmission revenue requirements included in the OATT rate calculation for the Company's pricing zone under the MISO Transmission and Energy Markets Tariff (MISO TEMT). The OATT rate calculation is shown on Attachment 11. Attachment 12 shows the projects eligible to receive the OATT revenue credit.

Xcel Energy operates the transmission assets of Northern States Power Company – Minnesota (NSPM) and Northern States Power Company – Wisconsin (NSPW) as one transmission system. Pursuant to the terms of the Federal Energy Regulatory Commission (FERC) regulated *Restated Agreement to Coordinate Planning and Operations and Interchange Power and Energy between Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin)* (Interchange Agreement), all transmission costs are shared between NSPM and NSPW based on load ratio share using a FERC-approved 36-month coincident peak demand allocator. The NSPM portion is then further allocated to its respective state jurisdictions (North Dakota, South Dakota, and Minnesota) based on a similar 12 month coincident peak (CP) methodology. A composite allocator is derived for purposes of assigning the transmission revenue requirements to North Dakota, as shown on Attachment 10.

For purposes of calculating projected revenue requirements, the Company proposes to allocate based on 2016 forecasted demand. Any resulting over- or under- recovery from customers as a result of the use of forecasted demand will be reflected in the true-up of actual revenues at the time the 2017 TCR rate is being determined. These demand allocators are shown in Attachment 10.

In addition, we include the following investment-related costs: property taxes, current and deferred taxes and book depreciation. Attachment 14 shows the revenue requirement calculations for the proposed TCR projects.

B. Capital Structure

The Company has calculated the revenue requirements consistent with the approved *Revised Second Amended Settlement* in Case No. PU-12-813. The capital structure approved in that docket was included on Attachment D of the Settlement Agreement.

C. TCR Tracker Account

To ensure that customers are not under or overcharged, we will record the actual TCR revenues and costs in a tracker account as the accounting mechanism for eligible TCR project costs. Any differences based on the estimated end of year balance in the tracker account will be returned or collected as part of our next TCR rate factor application.

The revenue requirements included in the tracker are only those related to North Dakota's share of eligible transmission projects. In making our calculations, the Company used the most current data available at the time of this filing and applied the composite demand allocator, which serves to:

- Allocate a share of the total costs to NSPW; and
- Exclude the portion of NSPM costs not related to serving North Dakota retail customers. This step allocates a share of costs to the South Dakota and Minnesota retail jurisdictions, and to the firm requirements wholesale sales jurisdiction.³

The result of this allocation process is that North Dakota electric customers are allocated approximately 5.22 percent of 2016 total transmission costs. By performing this cost allocation process, we ensure that electric customers in other jurisdictions are allocated a share of TCR revenue requirements, consistent with the Company's allocation of similar costs in a general rate case.

Each month as revenues are collected from retail customers, the Company tracks the amount of recovery under the TCR rate factor and compares that amount with the actual monthly revenue requirements. The difference is recorded in the tracker account as the amount of over- or under-recovery. Any over- or under-recovery balance at the end of the year is used in the calculation of the rate factor for the next year's forecasted revenue requirement.

D. Accounting for the Tracker

Xcel Energy calculates the monthly North Dakota jurisdictional revenue requirements (including appropriate overall return, income taxes, property taxes and depreciation), and compares them with monthly TCR rate rider recoveries from customers. The under-recovered amounts are recorded in FERC Account 182.3, Other Regulatory

³ NSPM currently does not have any full requirements wholesale customer on the NSP system.

Assets and the over-recovered amounts are recorded in FERC Account 254, Other Regulatory Liabilities (the Tracker Accounts).

V. RATE APPLICATION AND IMPACT

A. Rate Factor

Our TCR rate design is the annual calculated revenue requirements divided by the total annual forecast energy sales to North Dakota electric retail customers from January through December 2016. The rate is rounded to the nearest \$0.000001 per kWh. This calculation is shown on Attachment 7. Based on this rate design, we propose the following TCR adjustment factor:

Table 1: 2014 and 2015 Rate Factor Calculation

	Retail
TCR Adjustment Factor Cost Per kWh	\$0.002332
ND retail Sales <i>Jan - Dec. 2016</i>	2,309,682,896 kWh
ND retail revenue requirement <i>Jan. - Dec. 2016</i>	\$5,386,211

The average bill impact for a residential customer using 750 kWh per month would be \$1.75 per month.

The rate factor is based on forecast costs for the 2015 and 2016 calendar years. For each 12-month period ending December 31, a true-up adjustment will be recorded to reset the Tracker Account. The true-up will reflect the difference between the TCR revenues and the actual revenue requirements for the period.

B. Tariff

Xcel Energy proposes to revise its Transmission Cost Recovery Rider tariff sheet number 86 in Section 5 of the North Dakota Electric Rate Book—NDPSC No. 2. Attachment 15 depicts the proposed tariff sheet that would implement the revised Transmission Cost Recovery Rider Adjustment Factor in both redline and clean versions. The proposed tariff provides that the TCR rate will be applied to customer bills subsequent to Commission approval. The tariff sheet we have submitted provides a proposed effective date of January 1, 2016. However, the tariff sheet and

revised TCR factor will not be made effective until after the Commission acts on this application.

The TCR tariff sheet and final TCR rate factor will be revised appropriately to comply with the Commission's final order in this proceeding. If the TCR rate adjustment is not made effective January 1, 2016, or if the Commission determines modifications should be made to the level of revenues we have identified for TCR recovery, the Company proposes to calculate the final TCR factor based on the approved revenue requirement and forecasted sales over the remaining months of 2016. We will file our next TCR rate adjustment filing in late 2016 to be effective January 1, 2017.

C. Notice to Customers

The Company plans to provide notice to customers regarding a change in the TCR rate factor reflected in their monthly electric bill. The following is our proposed language to be included as a notice on the customers' bills the month the TCR factor is implemented:

The Transmission Cost Recovery (TCR) line item on your bill funds investments in new and modified transmission power lines, substations, and equipment. Beginning this month, the TCR rate is \$0.002332 per kWh, in effect for all electric customers.

We will work with Commission Staff if there are any suggestions to modify this proposed customer notice.

APPEARANCE OF COUNSEL

The Company will be represented in this proceeding by the following counsel upon whom all pleadings, documents and other filings should be served:

Alison Archer
Assistant General Counsel
Xcel Energy
414 Nicollet Mall, 5th Floor
Minneapolis, MN 55401
Alison.C.Archer@xcelenergy.com

We request that all communications regarding this proceeding, including data requests, also be directed to:

SaGonna Thompson
Regulatory Administrator
Xcel Energy Services Inc.
414 Nicollet Mall
Minneapolis, MN 55401
Regulatory.Records@xcelenergy.com

CONCLUSION

Xcel Energy respectfully requests that the Commission approve the proposed transmission projects as eligible for recovery through the existing TCR Rider, and approve the proposed TCR Rider rate for 2016 described in this filing. This factor is designed to recover the costs associated with significant investments in needed transmission infrastructure that are not presently reflected in our general rate schedules.

Dated: October 1, 2015

Northern States Power Company

TCR Rate Rider Application Attachments Table of Contents

1. Project Descriptions
2. Project Schedules
3. Capital Expenditure Forecast
4. Annual Tracker Summary
5. 2014 Tracker
6. 2015 Tracker
7. 2016 Tracker
8. 2017 Tracker
9. Revenues
10. Universal Inputs
11. OATT Adjustment Factor Calculation
12. Inputs that Differ by Project
13. RECB
14. Annual Revenue Requirement by Project
15. Proposed Tariff Sheet

Transmission Cost Recovery Rider Descriptions of Projects Proposed to be Eligible

The following projects were presented to the Commission as part of the Settlement agreement in the last electric rate case (Case No. PU-12-813) as appropriate for recovery in the Company's Transmission Cost Recovery Rider. The Commission affirmed these projects for TCR inclusion in Case No. PU-14-644. These projects' scopes have not significantly changed since we filed our last TCR application, and therefore we have not included descriptions below.

- CapX2020 Brookings – Twins Cities 345 kV transmission line
- CapX2020 Fargo – Twin Cities 345 kV transmission line
- CapX2020 La Crosse-Local 345 kV transmission line
- CapX2020 La Crosse-MISO
- CapX2020 La Crosse-WI
- Sioux Falls Northern
- Chaska – Hwy 212 Conversion
- Minn Valley
- Maple River – Red River
- Big Stone – Brookings 345 kV transmission line
- Lake Marion - Burnsville
- Maple Lake – Annandale
- Glencoe – Waconia
- Bluff Creek – Westgate
- Scott County 345 kV Expansion
- Wilson Substation Conversion
- Kohlman Lake – Goose Lake
- Prairie Sub Expansion
- Black Dog – Savage
- Chisago 2nd Transformer Addition
- Franklin Transformer
- Cass County Sub Expansion
- New Prague Area
- End of Life Replacement – Breakers
- End of Life Replacement – Relay

The Company seeks TCR Rider eligibility determination for the following projects and provides project descriptions below:

1. Minot Load Serving Project

Project Description and Context

This project involves construction of a new 230 kV substation in southeastern Minot, ND and a 19-mile 230 kV transmission line between Great River Energy's McHenry Substation in Velva, ND and the new substation in Minot, ND to meet the NERC TPL-002 and TPL-003 standard. The existing 115 kV lines in the area will be connected to this new substation. This project is needed for reliability purposes to maintain voltage levels under contingency conditions. The area is currently growing and the existing infrastructure is both aged and inadequate to serve the electrical need. The substation will inject 230 kV into the area and be tied to a sister Basin Electric Power Cooperative substation, adding strength and grid resilience. The project will require approval of an ADP and CPCN from the Commission.

2. NSPM Major Line Rebuild

Project Description and Context

This group of projects is to rebuild large segments of transmission lines in ND, SD, and MN that have been identified and reported to have a concentrated number of defects that contribute to poor line performance. These projects are typically required because the lines being rebuilt often experience outages with increasing frequency and duration as the structural integrity diminishes they must be replaced before eminent failure.

3. Gleason Lake Substation

Project Description and Context

This project scope includes the installation of a new 115 kV capacitor bank, the expansion of the existing ring bus at the Company's Gleason Lake Substation, in Wayzata, MN and the rebuild of the 115 kV double circuit transmission lines between Gleason Lake Substation and Parkers Lake Substation.

This project is needed because Gleason Lake Substation experiences low voltage to its 115 kV system during an outage to either Gleason Lake to Parkers Lake 115 kV lines. Loss of the 115 kV breaker at Gleason Lake would cause outage to both 115 kV Gleason Lake to Parkers Lake transmission lines because both lines share this breaker.

Substation modifications at Gleason Lake will be combined with a rebuild of the Gleason Lake to Parkers Lake double circuit 115 kV lines which will separate them into two single circuit 115 kV lines. The addition of a new capacitor bank at Gleason Lake will alleviate and stabilize the low voltage issues at Gleason Lake should the system experience loss of both Gleason Lake to Parkers Lake 115 kV lines. When this project is complete, a single initiating event (loss of the single breaker at Gleason Lake or loss of a common transmission line structure) that causes low voltage at Gleason Lake will be eliminated.

4. Galloping Mitigation Project

Project Description and Context

This project includes the reconductoring of two segments of NSPM line number 0953. The purpose of the project is to mitigate galloping on the line that has caused multiple outages and damage to the existing conductor and structures.

Twenty-one outages have been recorded over the past five years that have been directly attributed to galloping.

The first phase of the project updates approximately 22.4 circuit miles of 345 kV line from a double bundle conductor to a double bundle of twisted pair conductor between Nobles County Substation and Lakefield Junction Substation located in southwest Minnesota. The second phase of the project updates approximately 10.7 circuit miles of 345 kV line from a double bundle conductor to a double bundle of twisted pair conductor and installs anti-galloping devices on approximately 21 circuit miles between Split Rock Substation and Nobles County Substation located in southwest Minnesota.

5. Storm and Emergency - NSP Line

Project Description and Context

This group of projects is a funding program for equipment that fails in-service or is identified through condition assessment as having a high probability of failure and cannot wait for the next normal budget cycle for replacement. This work is typically identified through inspection for storm repairs and emergency situations which results in the replacement of arms, poles, conductor, insulators and other line appurtenances in North Dakota, South Dakota, and Minnesota.

6. End of Life Replacement (ELR) - Transformers

Project Description and Context

This group of projects is to replace existing transformers at multiple substations in North Dakota, South Dakota and Minnesota. The projects are part of the End of Life (ELR)/renewal program. These transformers are being replaced as part of the End of Life/Renewal program to phase out/update older substation equipment.

7. Maple River 115kV

Project Description and Context

This project is required because Minnkota Power Cooperative (MPC) has requested an interconnection at the Company's Maple River Substation near Fargo, North Dakota. MPC is converting an existing 69 kV line to be operated at 115 kV, which currently terminates at the Maple River Substation. The project provides for the installation of MPC's converted 115 kV transmission line at Maple River Substation and for the modification of the 115 kV yard from a five-position ring bus to a six-position ring bus. Other project components include four steel box structures, the final 115 kV transmission span into the substation, and underground fiber optic from the last transmission structure to the Electrical Equipment Enclosure. This work would be done after the addition of a new 115 kV line from Maple River to Red River Substation which will convert the existing four-position ring bus to a five-position ring bus.

8. Dean Lake Substation

Project Description and Context

The City of Shakopee requested that the Company expand its existing 115 kV Dean Lake Substation to accommodate their plans to add a third 115 kV-13.8 kV transformer at the Dean Lake Substation to connect that transformer to our transmission system. The Dean Lake Substation is owned by the Company, but currently contains distribution assets and transformers owned by the City of Shakopee. This project will construct the 5-position ring bus, which will involve adding two new 115 kV box structures and adding five breakers. The project also requires an electrical equipment enclosure and station auxiliary system to house our breaker controls and line relaying panels.

9. Transmission Line Relocation

Project Description and Context

The Transmission Line Relocation Program addresses situations where the Company is mandated to move or relocate assets due to road or highway projects that may result in negative impacts to public safety and/or the operation of the transmission system. In particular, some Company transmission assets are located on or along highway or road rights of way and the owners of these rights of way can require Xcel Energy to move the line on short notice. This program is to accommodate these moves. These projects tend to be similar to transmission rebuild projects, replacing existing poles, arms, insulators and conductors but normally adjacent to their present location.

10. Yankee Reactor

Project Description and Context

This project will install one new 115 kV three-phase set of switched reactors at the Yankee Substation, located in Elkton, Minnesota. The project includes grading and fencing an area for the expansion of the present 115 kV yard configuration.

Project Implementation Schedule

Project Name	Regulatory Approval Docket No.	Regulatory Approval Filing Date	Regulatory Approval Order Dates	Design/Engineering/Procurement	ROW Acquisition	Construction Start	Projected In-Service	Current Status
CapX2020 – La Crosse (Local, MISO, and WI)	E002/CN-06-1115 Local & MISO: ET-2/TL-09-1448 (MN) WI: 5-CE-136 (WI)	8/4/2006 1/19/2010 1/3/2011	MN Certificate of Need 5/22/2009 MN Route Permit 5/30/2012 WI Certificate of Public Convenience and Necessity 5/30/2012	October 2011	January 2012	January 2013	September 2016	The first phase segment of this project has been placed in-service with the second phase of this project projected to be placed in-service in Q3 2016. The final phase of this project is currently under construction.
CAPX2020 – Fargo	E002/CN-06-1115 E002, ET2/TL-09-246 E002, ET2/TL-09-1056	8/4/2006 4/8/2009 10/1/2009	Certificate of Need 5/22/2009 Monticello – St. Cloud Route Permit 7/12/2010 St. Cloud – Fargo Route Permit 5/1/2011	Monticello – St. Cloud Engineering Start 1/2/2010 Procurement Start 7/1/2010 St. Cloud – Fargo Engineering Start 10/1/2010 Procurement Start 7/1/2011	Monticello – St. Cloud 7/15/2010 St. Cloud – Fargo 5/15/2011	Monticello – St. Cloud 11/1/2010 St. Cloud – Fargo 12/26/2011	Monticello – St. Cloud 12/21/2011 St. Cloud – Fargo 10/15/2015	Monticello – St. Cloud segment is in-service. St. Cloud – Fargo segment project is substantially in-service as of Q2 2015. Remaining items to be placed in-service by year end are settlement costs for easement acquisition and land sales from Buy the Farm.

Project Implementation Schedule

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
CAPX2020 Brookings	E002/CN-06-1115	8/4/06	Certificate of Need 5/22/2009	November 2011	November 2011	October 2011	March 2015	This project is substantially in-service. Remaining spend in '16 and '17 forecast represent settlement costs for easement acquisition and land sales from Buy the farm.
	ET-2/TL-08-1474	12/29/2008	Route Permit MN 9/14/2010					
	EL10-016	11/23/2010	Route Permit SD 6/14/2011					
Sioux Falls Northern	No state permit is necessary.	No state permit is necessary.	Not required when using existing corridor.	March 2012	July 2012	August 2013	December 2015	Project under construction.
Chaska – Hwy 212	E002, ET2/TL-12-401	7/11/2012	MN Route Permit 10/15/2013	Phase 1 – April 2014 Phase 2 - October 2014	Phase 1 – March 2014 Phase 2 - September 2014	Phase 1 – March 2014 Phase 2 - September 2014	June 2015	Project in-service
Minn Valley	No state permit is necessary.	No state permit is necessary.	Not required for rebuild of existing line.	October 2013	December 2013	December 2013	December 2014	Project in-service.
Maple River – Red River	ND CPCN Required	State Route Permit not required	Certificate of Public Convenience and Necessity (CPCN)required, not yet submitted	December 2015	January 2016	November 2016	June 2017	Project is in final Planning, Engineering in preparation for CPCN Application filing
Big Stone – Brookings	EL12-063	12/19/2012	Facility Permit for 35 miles of planned line issued January 2007 (recertified April 2013) Facility Permit for 40 miles of planned line issued February 2014	June 2014	December 2016	August 2015	September 2017	Order Granting Certification 5/10/2013. Project under Construction.
	EL13-020	6/3/2013						

Project Implementation Schedule

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
Lake Marion – Burnsville	No state permit is necessary.	No state permit is necessary.	Not required for rebuild of existing line.	June 2013	October 2013	December 2012	May 2014	Project is In-service.
Maple Lake – Annandale	No state permit is necessary.	No state permit is necessary.	Not required for rebuild of existing line.	June 2013	N/A	September 2015	December 2015	Project is in final Planning, Engineering and Preconstruction.
Glencoe – Waconia	E002/TL-10-249	12/10/2010	MN Route Permit 10/11/2011/CON 11/14/2011	July 2013	September 2012	September 2012	December 2013	Project is In-service
Bluff Creek – Westgate	E002, ET2/TL-11-948	4/12/2012	MN Route Permit 1/21/2014	July 2014	August 2014	September 2012	December 2015	Project under construction
Scott County Expansion	E-002/MC-14-163	2/25/2014	4/2/2014	October 2014	July 2014	July 2014	September 2015	Project is In-Service
Wilson Substation	No state permit is necessary	No state permit is necessary	Not required for substation expansion	October 2018	January 2018	September 2018	December 2019	Project is in final Planning, Engineering and Preconstruction
Kohlman Lake – Goose Lake	E-002/TL-12-1151	1/17/2013	1/21/2014	March 2015	September 2014	October 2014	July 2015	Project is In-Service
Prairie Sub	PU-14-126 (CPCN Only)	3/14/2014	5/28/2014	June 2016	N/A	September 2014	June 2016	Project under construction
Black Dog – Savage	E-002/TL-11-795	2/14/2012	5/3/2013	December 2013	August 2013	August 2013	September 2014	Project is In-service
Chisago Transformer	No state permit is necessary	No state permit is necessary	Not required for substation expansion	September 2014	June 2014	June 2014	June 2015	Project is In-service
Franklin Transformer	No state permit is necessary	No state permit is necessary	Not required for substation expansion	January 2013	October 2012	October 2012	March 2014	Project Complete
Cass County Sub	No state Permit necessary	No state Permit necessary	No state Permit necessary	March 2013	October 2012	October 2012	December 2013	Project Complete
New Prague Area	No state permit is necessary	No state permit is necessary	No state permit is necessary	November 2014	July 2014	May 2015	December 2015	Project under construction

Project Implementation Schedule

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
ELR – Breakers	No state permit is necessary	No state permit is necessary	No state permit is necessary	Ongoing	N/A	Ongoing	Annual program replacement, varying ISDs throughout the year.	Ongoing
ELR – Relays	No state permit is necessary	No state permit is necessary	No state permit is necessary	Ongoing	N/A	Ongoing	Annual program replacement, varying ISDs throughout the year.	Ongoing
Minot Load Serving	ND CPCN Required	Anticipated Q2 2017	Certificate of Public Convenience and Necessity (CPCN), Certificate of Corridor Compatibility, and State Route Permit required, not yet submitted	October 2016	November 2017	February 2018	June 2019	Project is in final Planning, Engineering and Preconstruction.
NSPM Major Line Rebuild	No state permit is necessary.	No state permit is necessary.	No state permit is necessary.	Ongoing	Ongoing as necessary	Ongoing	Annual program replacement, varying ISDs throughout the year.	Ongoing
Gleason Lake Sub	No state permit is necessary.	No state permit is necessary.	No state permit is necessary.	February 2017	February 2017	October 2017	June 2018	Project is in final Planning, Engineering
Galloping Mitigation NSM 0953	No state permit is necessary.	No state permit is necessary.	Not required for rebuild of existing line.	Phase 1 – May 2015 Phase 2 – Aug. 2017	Phase 1 – n/a Phase 2 – n/a	Phase 1 – July 2015 Phase 2 – May 2018	Phase 1 – August 2015 Phase 2 – December 2018	Phase 1 is in-service. Phase 2 is in project planning and engineering phase.

Project Implementation Schedule

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
S&E - NSP Line	No state permit is necessary	No state permit is necessary	No state permit is necessary	Ongoing	N/A	Ongoing	Annual program replacement, varying ISDs throughout the year.	Ongoing
ELR - Transformers NSPM	No state permit is necessary	No state permit is necessary	No state permit is necessary	Ongoing	N/A	Ongoing	Annual program replacement, varying ISDs throughout the year.	Ongoing
Maple River Interconnection	No state permit is necessary	No state permit is necessary	No state permit is necessary	November 2016	N/A	May 2017	February 2018	Project is in final Planning, Engineering
Dean Lake Substation	No state permit is necessary	No state permit is necessary	No state permit is necessary	November 2015	N/A	March 2016	December 2016	Project is in final Planning, Engineering
NSP Reloc B	No state permit is necessary	No state permit is necessary	No state permit is necessary	Ongoing	Ongoing as necessary	Ongoing	Ongoing	Ongoing
Yankee Reactor	No state permit is necessary	No state permit is necessary	No state permit is necessary	October 2015	N/A	June 2016	September 2016	Project is in final Planning, Engineering and Preconstruction.

Capital Expenditure Forecast Through 2020																		
Total: Transmission Statute Projects																		
		41,022,105	275,286,888	387,229,886	351,588,645	239,545,147	100,858,235	71,628,357	47,642,080	38,195,048	-	1,552,996,391	1,552,996,391	1,366,764,839	1,366,764,839	31,653,738		
Project Name	Sub Project	Eligibility Date	AFUDC Pre-Eligible Total	Pre-2013	2013	2014	2015	2016	2017	2018	2019	2020	Total by Subproject	Total by Project	Previous Filing by Subproject	Previous Filing by Project	Variance \$s	Variance %
CAPX2020 - Brookings	Land	Jan-14	186,176	14,536,466	16,661,722	8,150,500	3,308,471	1,684,400	(788,600)	-	-	-	43,739,135	-	44,327,260	-	-	-
CAPX2020 - Brookings	Line	Jan-14	19,081,643	96,290,852	140,338,580	93,405,550	13,343,463	-	-	-	-	-	362,460,087	-	350,104,341	-	-	-
CAPX2020 - Brookings	Sub	Jan-14	2,484,549	23,981,514	21,302,621	20,318,451	1,023,144	-	-	-	-	-	69,110,279	475,309,502	71,023,644	465,455,235	9,854,267	2%
CAPX2020 - Fargo	Line	Jan-14	8,916,596	63,591,084	70,145,899	44,914,549	7,719,744	-	-	-	-	-	195,287,873	-	200,420,557	-	-	-
CAPX2020 - Fargo	Sub	Jan-14	1,644,925	22,467,658	7,674,224	7,589,264	1,236,840	-	-	-	-	-	40,612,912	235,900,784	38,969,581	239,390,138	(3,489,354)	-1%
CAPX2020 - La Crosse Local	Land	Jan-14	-	1,336,265	1,387,200	503,247	531,593	-	-	-	-	-	3,758,305	-	3,720,759	-	-	-
CAPX2020 - La Crosse Local	Line	Jan-14	1,975,328	545,153	33,580,536	23,017,878	1,953,883	1,800,000	-	-	-	-	62,824,576	-	62,824,576	-	-	-
CAPX2020 - La Crosse Local	Sub	Jan-14	60,257	89,595	3,020,987	1,079,120	9,327	-	-	-	-	-	4,259,286	70,890,369	4,434,458	70,979,793	(89,424)	0%
CAPX2020 - La Crosse MISO	Land	Jan-14	-	-	15,269	856,203	525,785	-	-	-	-	-	1,397,258	-	1,452,912	-	-	-
CAPX2020 - La Crosse MISO	Line	Jan-14	2,553,627	12,198,197	3,796,021	8,459,173	46,332,018	19,095,000	-	-	-	-	92,434,035	-	81,296,773	-	-	-
CAPX2020 - La Crosse MISO	Sub	Jan-14	412,096	2,215,605	12,561,924	2,441,126	174,305	-	-	-	-	-	17,805,056	111,636,349	18,541,727	101,291,412	10,344,937	10%
CAPX2020 - La Crosse MISO - WI	Land	Jan-14	-	33,597	2,928,185	2,945,828	2,288,199	500,000	-	-	-	-	8,695,609	-	7,400,099	-	-	-
CAPX2020 - La Crosse MISO - WI	Line	Jan-14	607,046	6,528,746	10,535,835	59,950,263	36,570,706	1,000,000	-	-	-	-	115,192,395	-	109,708,256	-	-	-
CAPX2020 - La Crosse MISO - WI	Sub	Jan-14	180,638	58,372	12,512,642	9,654,358	2,593,014	500,000	-	-	-	-	25,499,024	149,387,028	27,973,294	145,081,649	4,305,379	3%
Sioux Falls Northern	Land	Jan-14	-	-	188,682	271,109	61,707	-	-	-	-	-	521,499	-	383,411	-	-	-
Sioux Falls Northern	Line	Jan-14	44,098	158,169	1,439,889	4,558,059	17,585,431	539,491	-	-	-	-	24,325,137	-	23,067,113	-	-	-
Sioux Falls Northern	Sub	Jan-14	57,484	81,852	3,886,337	5,696,176	1,142,660	29,420	-	-	-	-	10,893,930	35,740,566	10,459,380	33,909,904	1,830,662	5%
Chaska - Hwy 212 Conversion	Land	Jan-14	-	91,988	523,610	880,103	15,471	-	-	-	-	-	1,511,172	-	1,158,259	-	-	-
Chaska - Hwy 212 Conversion	Line	Jan-14	73,049	1,520,320	865,959	4,712,136	5,817,138	-	-	-	-	-	12,988,602	-	9,800,215	-	-	-
Chaska - Hwy 212 Conversion	Sub	Jan-14	108,350	2,028,425	1,061,185	2,204,301	1,276,508	-	-	-	-	-	21,178,543	21,178,543	18,159,084	3,019,459	17%	
Minn Valley	Line	Jan-14	73,012	1,270	4,449,404	9,771,601	570,694	-	-	-	-	-	14,865,982	-	13,898,596	-	-	-
Minn Valley	Sub	Jan-14	3,965	-	139,970	578,306	18,173	-	-	-	-	-	740,414	15,606,396	213,863	14,112,459	1,493,937	11%
Maple River - Red River	Land	Jan-14	-	-	-	-	-	4,657,650	224,000	-	-	-	4,881,650	-	4,840,488	-	-	-
Maple River - Red River	Line	Jan-14	1,254	-	42,281	82,833	95,262	3,298,029	3,378,828	-	-	-	6,998,467	-	5,475,725	-	-	-
Maple River - Red River	Sub	Jan-14	-	-	-	-	23,790	2,003,871	1,747,400	-	-	-	3,775,051	15,555,188	13,139,213	2,415,975	18%	
Big Stone - Brookings	Land	Jan-14	(0)	2,239,046	(2,239,046)	3,357,788	205,232	390,300	-	-	-	-	3,953,320	-	2,035,500	-	-	-
Big Stone - Brookings	Line	Jan-14	202,520	223,994	2,941,649	(841,353)	5,012,836	36,580,850	27,100,000	2,500,000	-	-	73,720,495	-	77,718,857	-	-	-
Big Stone - Brookings	Sub	Jan-14	139	1,495	27,857	30,077	7,654	2,845,200	3,709,400	-	-	-	6,621,822	84,295,638	6,584,455	86,338,812	(2,043,174)	-2%
Lake Marion - Burnsville	Land	Jan-14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lake Marion - Burnsville	Line	Jan-14	100,700	233,585	6,395,911	5,047,727	18,197	-	-	-	-	-	11,796,120	-	12,898,551	-	-	-
Lake Marion - Burnsville	Sub	Jan-14	630	7,260	584	(7,844)	-	-	-	-	-	-	630	11,805,411	157,430	13,064,642	(1,259,231)	-10%
Maple Lake - Annandale	Line	Jan-14	1,169	-	78,940	203,018	2,350,769	-	-	-	-	-	2,633,896	2,633,896	2,921,326	2,921,326	(287,430)	-10%
Glencoe - Waconia	Land	Jan-14	0	348,712	130,860	46,616	-7,505	0	0	0	0	0	518,683	-	480,546	-	-	-
Glencoe - Waconia	Line	Jan-14	661,082	10,025,391	7,402,771	335,871	19,958	0	0	0	0	0	18,445,072	-	18,215,751	-	-	-
Glencoe - Waconia	Sub	Jan-14	222,526	2,635,487	1,570,134	-288,780	123,870	0	0	0	0	0	4,133,787	23,226,791	4,133,787	22,830,084	396,707	2%
Bluff Creek - Westgate	Land	Jan-14	-	-	-	-	-	-	-	-	-	-	-	-	396,000	-	-	-
Bluff Creek - Westgate	Line	Jan-14	0	708,533	259,801	130,199	33,013	1,241,660	0	0	0	0	2,373,206	-	2,513,380	-	-	-
Bluff Creek - Westgate	Sub	Jan-14	0	0	0	2,921,966	14,476,607	3,948,420	-	-	-	-	21,346,092	23,720,199	22,346,092	25,255,472	-1,535,273	-6%
Scott Cty 345 kV Expansion	Line	Jan-14	1,033	-	71,965	921,723	6,746,144	-	-	-	-	-	7,740,865	-	4,908,108	-	-	-
Scott Cty 345 kV Expansion	Sub	Jan-14	2,046	-	65,672	7,083,920	14,749,136	-	-	-	-	-	21,900,774	29,641,639	24,282,666	29,191,774	449,865	2%
Wilson Substation Conversion	Line	Jan-14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wilson Substation Conversion	Sub	Jan-14	-	-	-	-	-	-	-	2,940,000	13,720,000	-	16,660,000	16,660,000	13,539,876	17,543,666	(883,666)	-5%
Kohlman Lake-Goose Lake 2nd ckt	Land	Jan-14	-	47,572	34,077	98,205	1,639	-	-	-	-	-	181,493	-	83,966	-	-	-
Kohlman Lake-Goose Lake 2nd ckt	Line	Jan-14	13,818	110,247	183,147	3,349,600	3,512,842	-	-	-	-	-	7,169,654	-	5,412,763	-	-	-
Kohlman Lake-Goose Lake 2nd ckt	Sub	Jan-14	104,926	621,422	2,690,418	6,449,467	2,577,146	-	-	-	-	-	12,443,379	19,794,525	10,420,755	15,917,484	3,877,041	24%
Prairie Sub Expansion	Line	Jan-14	1,071	-	314,269	-	-	-	-	-	-	-	315,340	-	315,340	-	-	-
Prairie Sub Expansion	Sub	Jan-14	942	-	37,448	2,426,187	7,208,832	2,018,800	-	-	-	-	11,692,210	12,007,550	11,907,412	12,222,752	(215,202)	-2%
Black Dog - Savage	Line	Jan-14	77,764	103,749	6,630,228	3,459,354	27,855	-	-	-	-	-	10,298,950	-	9,449,667	-	-	-
Chicago 2nd Transformer Addition	Sub	Jan-14	4,862	29,709	129,982	1,854,123	6,060,253	-	-	-	-	-	8,078,929	-	7,876,906	-	-	-
Franklin Transformer	Sub	Jan-14	443,324	4,123,622	3,251,152	334,829	5,399	-	-	-	-	-	8,158,326	-	8,105,837	-	-	-
Cass County SUB Expansion	Line	Jan-14	14,403	45,479	454,747	11,931	-	-	-	-	-	-	526,560	-	520,525	-	-	-
Cass County SUB Expansion	Sub	Jan-14	247,026	693,028	4,861,919	87,833	(1,792)	-	-	-	-	-	5,888,014	6,414,574	5,834,383	6,354,908	59,666	1%
New Prague Area	Land	Jan-14	-	-	-	-	103,977	-	-	-	-	-	-	-	-	-	-	-
New Prague Area	Line	Jan-14	-	-	-	219,745	1,514,817	19,600	-	-	-	-	1,754,163	-	1,330,755	-	-	-
New Prague Area	Sub	Jan-14	-	-	-	426,725	6,174,372	34,300	-	-	-	-	6,635,397	8,493,537	4,580,183	5,910,938	2,582,599	44%
ELR - Breakers - NSPM	Sub	Jan-14	9,433	32,395	199,756	278,654	(2,284)	-	-	-	-	-	517,955	517,955	753,176	753,176	(235,221)	-31%
Minot Load Serving	Land	Jan-16	-	-	-	-	619,000	2,586,000	209,000	10,000	-	-	3,424,000	-	-	-	-	-
Minot Load Serving	Line	Jan-16	14,114	-	-	42,228	506,339	1,852,957	23,981,458	21,507,020	978,798	-	48,882,913	-	52,306,913	-	-	-
Minot Load Serving	Sub	Jan-16	37,780	-	-	-	5,675,697	294,000	49,000	6,977,600	17,391,630	-	30,425,707	-	30,425,707	-	-	-
Gleason Lake Sub	Sub	Jan-16	-	-	-	-	-	2,498,800	5,952,800	5,504,760	-	-	13,956,360	-	13,956,360	-	-	-
NSM0953 Galloping Mitigate SPK	Line	Jan-16	166,10															

Annual Tracker Summary				
	2014	2015	2016	2017
	Actual	Forecast	Forecast	Forecast
Legacy Projects	-	-	-	-
CAPX2020 - Brookings	2,850,414	3,066,222	3,059,257	2,988,808
CAPX2020 - Fargo	1,352,663	1,593,498	1,545,399	1,502,261
CAPX2020 - La Crosse Local	264,997	381,513	364,473	361,796
CAPX2020 - La Crosse MISO	274,901	389,507	685,850	799,160
CAPX2020 - La Crosse MISO - WI	340,552	888,979	1,016,212	991,770
Sioux Falls Northern	55,702	127,143	197,090	199,177
Chaska - Hwy 212 Conversion	48,753	102,125	113,897	110,632
Minn Valley	67,305	98,832	98,682	96,119
Maple River - Red River	403	894	17,970	74,534
Big Stone - Brookings	24,207	44,081	166,003	421,937
Lake Marion - Burnsville	63,588	60,954	58,460	56,968
Maple Lake - Annandale	929	4,534	15,589	15,026
Glencoe - Waconia	154,015	144,153	142,818	139,440
Bluff Creek - Westgate	8,831	53,343	120,886	138,148
Scott Cty 345 kV Expansion	10,604	114,744	169,608	163,735
Wilson Substation Conversion	-	-	-	-
Kohlman Lake-Goose Lake 2nd ckt	57,539	121,573	132,000	128,134
Prairie Sub Expansion	3,252	27,906	58,274	71,340
Black Dog - Savage	54,365	54,088	51,109	49,802
Chisago 2nd Transformer Addition	5,430	36,716	47,851	46,084
Franklin Transformer	49,106	41,355	39,696	38,749
Cass County SUB Expansion	35,368	32,297	30,991	30,247
New Prague Area	1,027	19,687	50,129	48,387
ELR - Breakers - NSPM	2,526	2,634	2,521	2,459
Minot Load Serving	-	-	12,530	72,297
NSPM Major Line Rebuild	-	-	35,562	34,813
Gleason Lake Sub	-	-	4,652	25,379
NSM0953 Galloping Mitigate SPK	-	-	48,542	46,908
S&E - NSP Line	-	-	62,149	70,728
ELR - Transformers - NSPM	-	-	29,983	31,540
Maple River 115kV MPC Interconnect	-	-	197	4,611
Dean Lake Substation	-	-	17,334	28,801
NSP Reloc B	-	-	13,482	27,962
Yankee Reactor	-	-	20,549	27,656
ELR - Relay - NSPM	8,466	7,449	7,127	6,937
RECB - 26 & 26(a)	(2,076,731)	(1,612,962)	(1,413,134)	(652,259)
Transmission Projects	3,658,211	5,801,265	7,023,741	8,200,086
Revenue Requirement in Base Rates	(1,800,376)	(1,800,376)	(1,800,376)	(1,800,376)
TCR True-up Carryover	-	1,857,835	162,845	31
Revenue Requirement (RR)	1,857,835	5,858,723	5,386,211	6,399,740
Revenue Collections (RC)	-	5,695,878	5,386,181	6,399,690
RR - RC	1,857,835	162,845	31	51
Balance	1,857,835	162,845	31	51

2014 Tracker													
Carryover	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Annual Total
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual
Legacy Projects	-	-	-	-	-	-	-	-	-	-	-	-	-
CAPX2020 - Brookings	168,846	177,641	185,349	221,675	252,634	256,428	260,256	263,976	265,603	265,719	265,265	267,023	2,850,414
CAPX2020 - Fargo	93,999	96,317	98,276	106,500	114,511	115,898	116,974	118,466	120,722	122,471	123,521	125,007	1,352,663
CAPX2020 - La Crosse Local	16,858	18,020	18,826	19,477	20,264	20,736	22,403	24,353	25,290	25,785	26,241	26,743	264,997
CAPX2020 - La Crosse MISO	16,908	17,394	17,886	18,245	22,160	25,809	25,629	25,672	25,733	25,789	26,291	27,386	274,901
CAPX2020 - La Crosse MISO - WI	16,484	16,979	18,425	19,845	20,988	23,299	26,699	30,735	35,009	39,290	43,968	48,829	340,552
Sioux Falls Northern	2,370	2,793	3,200	3,527	4,312	4,927	5,027	5,183	5,409	5,868	6,353	6,733	55,702
Chaska - Hwy 212 Conversion	2,972	3,121	3,285	3,446	3,754	4,053	4,141	4,240	4,448	4,646	5,002	5,645	48,753
Minn Valley	2,293	2,454	2,620	2,787	2,954	4,624	6,340	7,053	7,808	8,120	8,473	11,779	67,305
Maple River - Red River	17	18	19	25	31	34	38	40	42	45	48	48	403
Big Stone - Brookings	1,633	1,654	1,682	1,711	1,761	1,800	1,867	1,955	2,138	2,431	2,695	2,881	24,207
Lake Marion - Burnsville	3,183	3,285	3,628	4,043	4,436	5,510	6,520	6,649	6,649	6,651	6,588	6,447	63,588
Maple Lake - Annandale	40	50	60	71	75	80	84	86	88	93	98	104	929
Glencoe - Waconia	13,087	13,001	12,878	12,865	12,845	12,817	12,790	12,776	12,763	12,745	12,723	12,727	154,015
Bluff Creek - Westgate	475	489	499	513	533	556	580	613	672	881	1,295	1,725	8,831
Scott City 345 kV Expansion	90	117	125	151	184	209	247	460	919	1,891	2,789	3,423	10,604
Wilson Substation Conversion	-	-	-	-	-	-	-	-	-	-	-	-	-
Kohlman Lake-Goose Lake 2nd ckt	2,006	2,443	2,860	3,182	3,499	4,360	5,167	5,313	6,160	7,107	7,396	8,046	57,539
Prairie Sub Expansion	168	168	168	168	172	180	189	200	219	244	482	896	3,252
Black Dog - Savage	2,659	2,802	3,014	3,326	3,611	3,710	3,754	5,446	6,669	6,574	6,474	6,327	54,365
Chisago 2nd Transformer Addition	64	70	83	98	119	146	185	285	712	1,191	1,375	1,102	5,430
Franklin Transformer	3,001	3,032	3,844	4,629	4,576	4,508	4,432	4,348	4,276	4,217	4,156	4,088	49,106
Cass County SUB Expansion	2,963	2,960	2,959	2,960	2,962	2,958	2,951	2,944	2,936	2,928	2,926	2,922	35,368
New Prague Area	-	0	5	15	23	58	96	116	137	157	190	229	1,027
ELR - Breakers - NSPM	92	93	94	129	188	227	271	297	292	287	281	275	2,526
Minot Load Serving	-	-	-	-	-	-	-	-	-	-	-	-	-
NSPM Major Line Rebuild	-	-	-	-	-	-	-	-	-	-	-	-	-
Gleason Lake Sub	-	-	-	-	-	-	-	-	-	-	-	-	-
NSM0953 Galloping Mitigate SPK	-	-	-	-	-	-	-	-	-	-	-	-	-
S&E - NSP Line	-	-	-	-	-	-	-	-	-	-	-	-	-
ELR - Transformers - NSPM	-	-	-	-	-	-	-	-	-	-	-	-	-
Maple River 115kV MPC Interconnection	-	-	-	-	-	-	-	-	-	-	-	-	-
Dean Lake Substation	-	-	-	-	-	-	-	-	-	-	-	-	-
NSP Reloc B	-	-	-	-	-	-	-	-	-	-	-	-	-
Yankee Reactor	-	-	-	-	-	-	-	-	-	-	-	-	-
ELR - Relay - NSPM	649	715	729	727	722	718	712	706	701	699	697	691	8,466
RECB - 26 & 26(a)	(186,464)	(170,741)	(180,195)	(156,610)	(114,172)	(197,405)	(164,374)	(180,933)	(170,620)	(172,665)	(230,947)	(151,605)	(2,076,731)
Transmission Projects	164,393	194,871	200,317	273,503	363,141	296,241	342,978	340,979	364,775	373,164	324,380	419,470	3,658,211
Revenue Requirement in Base Rates	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(1,800,376)
TCR True-up Carryover	-	-	-	-	-	-	-	-	-	-	-	-	-
Revenue Requirement (RR)	14,362	44,840	50,285	123,471	213,110	146,209	192,947	190,947	214,744	223,132	174,348	269,439	1,857,835
Revenue Collections (RC)	-	-	-	-	-	-	-	-	-	-	-	-	-
Monthly RR - RC	14,362	44,840	50,285	123,471	213,110	146,209	192,947	190,947	214,744	223,132	174,348	269,439	-
Balance (RR - RC + Cumulative CC)	14,362	59,202	109,488	232,959	446,068	592,278	785,225	976,172	1,190,915	1,414,048	1,588,396	1,857,835	

Carryover	2015 Tracker												Annual Total
	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	
	Actual (1)	Actual	Actual	Actual	Actual	Actual	Actual	Mixed	Forecast	Forecast	Forecast	Forecast	
Legacy Projects	-	-	-	-	-	-	-	-	-	-	-	-	-
CAPX2020 - Brookings	244,477	252,547	258,588	260,169	259,413	258,625	256,304	255,508	256,286	255,674	254,566	254,065	3,066,222
CAPX2020 - Fargo	122,646	124,320	124,581	132,519	140,099	138,673	137,064	136,170	135,665	134,933	133,958	132,870	1,593,498
CAPX2020 - La Crosse Local	26,423	26,773	26,851	26,767	26,707	26,818	26,888	33,641	40,715	40,664	39,990	39,275	381,513
CAPX2020 - La Crosse MISO	24,674	25,193	25,709	26,316	27,450	29,204	31,224	33,792	36,918	40,122	42,986	45,921	389,507
CAPX2020 - La Crosse MISO - WI	51,271	53,738	55,786	58,089	60,776	63,054	64,465	65,431	84,625	108,109	112,342	111,293	888,979
Sioux Falls Northern	6,987	7,800	8,572	9,012	9,714	10,430	10,852	11,252	11,695	12,392	13,243	15,194	127,143
Chaska - Hwy 212 Conversion	6,272	6,773	7,164	7,568	7,908	8,170	8,970	9,865	9,987	9,902	9,816	9,730	102,125
Minn Valley	8,109	8,289	8,277	8,257	8,246	8,242	8,260	8,270	8,250	8,230	8,211	8,191	98,832
Maple River - Red River	51	59	64	67	70	73	76	81	86	88	88	90	894
Big Stone - Brookings	3,107	3,128	3,167	3,235	3,325	3,396	3,454	3,530	3,771	4,157	4,622	5,190	44,081
Lake Marion - Burnsville	5,094	5,132	5,121	5,110	5,100	5,089	5,080	5,070	5,058	5,046	5,034	5,022	60,954
Maple Lake - Annandale	119	144	158	160	161	161	164	179	336	594	797	1,559	4,534
Glencoe - Waconia	12,001	12,095	12,079	12,059	12,064	12,070	12,034	12,000	11,978	11,951	11,924	11,898	144,153
Bluff Creek - Westgate	2,154	2,696	3,362	3,913	4,429	3,921	3,993	4,137	4,410	5,024	5,925	9,377	53,343
Scott Cty 345 kV Expansion	4,065	4,621	5,236	6,233	7,322	8,816	10,141	11,144	13,069	14,586	14,828	14,682	114,744
Wilson Substation Conversion	-	-	-	-	-	-	-	-	-	-	-	-	-
Kohlman Lake-Goose Lake 2nd ckt	7,358	8,023	8,531	9,651	10,650	10,998	11,224	11,193	11,111	11,028	10,945	10,861	121,573
Prairie Sub Expansion	1,103	1,151	1,360	1,660	1,886	2,143	2,381	2,551	2,972	3,395	3,527	3,777	27,906
Black Dog - Savage	4,522	4,564	4,631	4,663	4,665	4,556	4,440	4,430	4,420	4,409	4,399	4,388	54,088
Chisago 2nd Transformer Addition	1,183	1,735	2,390	2,976	3,073	3,407	3,686	3,678	3,666	3,653	3,641	3,629	36,716
Franklin Transformer	3,464	3,482	3,476	3,468	3,460	3,452	3,445	3,437	3,429	3,422	3,414	3,406	41,355
Cass County SUB Expansion	2,708	2,721	2,715	2,708	2,701	2,695	2,689	2,684	2,678	2,672	2,666	2,660	32,297
New Prague Area	274	340	429	541	709	1,050	1,567	1,999	2,383	2,778	3,005	4,614	19,687
ELR - Breakers - NSPM	222	223	222	221	220	220	219	219	218	218	217	217	2,634
Minot Load Serving	-	-	-	-	-	-	-	-	-	-	-	-	-
NSPM Major Line Rebuild	-	-	-	-	-	-	-	-	-	-	-	-	-
Gleason Lake Sub	-	-	-	-	-	-	-	-	-	-	-	-	-
NSM0953 Galloping Mitigate SPK	-	-	-	-	-	-	-	-	-	-	-	-	-
S&E - NSP Line	-	-	-	-	-	-	-	-	-	-	-	-	-
ELR - Transformers - NSPM	-	-	-	-	-	-	-	-	-	-	-	-	-
Maple River 115kV MPC Interconnection	-	-	-	-	-	-	-	-	-	-	-	-	-
Dean Lake Substation	-	-	-	-	-	-	-	-	-	-	-	-	-
NSP Reloc B	-	-	-	-	-	-	-	-	-	-	-	-	-
Yankee Reactor	-	-	-	-	-	-	-	-	-	-	-	-	-
ELR - Relay - NSPM	625	628	626	625	623	622	620	619	617	616	614	613	7,449
RECB - 26 & 26(a)	(167,938)	(154,852)	(110,473)	(143,992)	(106,377)	(100,899)	(109,312)	(112,191)	(142,686)	(164,195)	(146,321)	(153,725)	(1,612,962)
Transmission Projects	370,970	401,321	458,623	441,994	494,396	504,983	499,927	508,688	511,660	519,468	544,438	544,796	5,801,265
Revenue Requirement in Base Rates	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(1,800,376)
TCR True-up Carryover	1,857,835	1,857,835	-	-	-	-	-	-	-	-	-	-	1,857,835
Revenue Requirement (RR)	2,078,774	251,290	308,592	291,963	344,365	354,952	349,896	358,656	361,629	369,437	394,406	394,765	5,858,723
Revenue Collections (RC)	571,272	496,819	500,667	417,166	402,857	425,948	491,984	486,288	427,724	439,970	480,104	555,079	5,695,878
Monthly RR - RC	1,507,501	(245,529)	(192,076)	(125,203)	(58,492)	(70,996)	(142,088)	(127,632)	(66,096)	(70,533)	(85,697)	(160,314)	
Balance (RR - RC + Cumulative CC)	1,507,501	1,261,972	1,069,896	944,693	886,202	815,205	673,117	545,485	479,390	408,857	323,160	162,845	

Carryover	2016 Tracker												
	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Annual Total
	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Legacy Projects	-	-	-	-	-	-	-	-	-	-	-	-	-
CAPX2020 - Brookings	257,387	256,969	256,547	256,129	255,715	255,299	254,836	254,326	253,813	253,287	252,746	252,203	3,059,257
CAPX2020 - Fargo	130,542	130,223	129,903	129,583	129,263	128,943	128,623	128,304	127,984	127,664	127,344	127,024	1,545,399
CAPX2020 - La Crosse Local	30,186	30,282	30,370	30,410	30,405	30,386	30,401	30,392	30,434	30,474	30,402	30,331	364,473
CAPX2020 - La Crosse MISO	49,874	51,494	52,812	54,138	55,251	56,099	56,824	57,259	60,701	64,218	63,834	63,347	685,850
CAPX2020 - La Crosse MISO - WI	85,073	85,020	85,153	85,241	85,125	84,983	84,790	84,590	84,381	84,167	83,953	83,738	1,016,212
Sioux Falls Northern	15,970	16,052	16,387	16,705	16,660	16,614	16,567	16,520	16,474	16,427	16,380	16,334	197,090
Chaska - Hwy 212 Conversion	9,624	9,599	9,575	9,551	9,527	9,503	9,479	9,455	9,431	9,407	9,383	9,359	113,897
Minn Valley	8,329	8,310	8,290	8,271	8,252	8,233	8,214	8,195	8,176	8,157	8,137	8,118	98,682
Maple River - Red River	182	359	538	723	921	1,104	1,261	1,529	1,902	2,554	3,247	3,651	17,970
Big Stone - Brookings	5,950	6,715	7,684	8,902	10,379	12,057	13,942	16,029	18,197	20,221	22,119	23,807	166,003
Lake Marion - Burnsville	4,933	4,922	4,911	4,900	4,888	4,877	4,866	4,855	4,844	4,833	4,821	4,810	58,460
Maple Lake - Annandale	1,321	1,317	1,313	1,309	1,305	1,301	1,297	1,293	1,289	1,285	1,281	1,277	15,589
Glencoe - Waconia	12,042	12,016	11,991	11,965	11,940	11,914	11,889	11,863	11,838	11,812	11,787	11,761	142,818
Bluff Creek - Westgate	8,211	8,702	9,084	9,363	9,642	10,398	10,995	10,966	10,935	10,899	10,864	10,828	120,886
Scott Cty 345 kV Expansion	14,367	14,325	14,282	14,240	14,198	14,155	14,113	14,071	14,028	13,986	13,943	13,901	169,608
Wilson Substation Conversion	-	-	-	-	-	-	-	-	-	-	-	-	-
Kohlman Lake-Goose Lake 2nd ckt	11,156	11,128	11,099	11,071	11,043	11,014	10,986	10,957	10,929	10,901	10,872	10,844	132,000
Prairie Sub Expansion	3,895	4,111	4,244	4,331	4,400	4,899	5,408	5,434	5,415	5,397	5,378	5,360	58,274
Black Dog - Savage	4,313	4,303	4,293	4,283	4,274	4,264	4,254	4,244	4,235	4,225	4,215	4,205	51,109
Chisago 2nd Transformer Addition	4,057	4,045	4,032	4,019	4,007	3,994	3,981	3,969	3,956	3,943	3,931	3,918	47,851
Franklin Transformer	3,347	3,340	3,333	3,326	3,319	3,312	3,304	3,297	3,290	3,283	3,276	3,269	39,696
Cass County SUB Expansion	2,613	2,608	2,602	2,597	2,591	2,585	2,580	2,574	2,569	2,563	2,557	2,552	30,991
New Prague Area	4,235	4,234	4,224	4,211	4,198	4,185	4,173	4,160	4,147	4,134	4,121	4,108	50,129
ELR - Breakers - NSPM	213	212	212	211	211	210	210	209	209	208	208	207	2,521
Minot Load Serving	289	466	679	797	916	1,035	1,154	1,273	1,404	1,547	1,530	1,440	12,530
NSPM Major Line Rebuild	2,946	3,005	2,997	2,989	2,981	2,973	2,965	2,957	2,949	2,941	2,933	2,925	35,562
Gleason Lake Sub	12	36	67	112	178	232	303	441	604	745	866	1,055	4,652
NSM0953 Galloping Mitigate SPK	4,111	4,099	4,087	4,075	4,063	4,051	4,039	4,027	4,015	4,003	3,991	3,979	48,542
S&E - NSP Line	5,133	5,127	5,120	5,114	5,110	5,118	5,130	5,135	5,139	5,193	5,301	5,529	62,149
ELR - Transformers - NSPM	2,469	2,507	2,527	2,525	2,518	2,511	2,505	2,498	2,491	2,484	2,478	2,471	29,983
Maple River 115kV MPC Interconnection	-	-	-	-	1	4	9	15	24	36	47	61	197
Dean Lake Substation	87	551	1,040	1,171	1,302	1,433	1,564	1,696	1,828	1,960	2,092	2,611	17,334
NSP Reloc B	605	614	680	818	997	1,111	1,134	1,192	1,311	1,474	1,672	1,874	13,482
Yankee Reactor	663	1,219	1,685	1,725	1,765	1,805	1,825	1,844	1,889	1,960	2,053	2,116	20,549
ELR - Relay - NSPM	602	600	599	597	596	595	593	592	590	589	587	586	7,127
RECB - 26 & 26(a)	(117,959)	(106,049)	(141,652)	(124,509)	(79,291)	(66,188)	(114,395)	(133,040)	(112,070)	(139,725)	(160,966)	(117,291)	(1,413,134)
Transmission Projects	566,779	582,462	550,711	570,897	618,649	635,012	589,818	573,121	599,348	577,251	557,384	602,309	7,023,741
Revenue Requirement in Base Rates	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(1,800,376)
TCR True-up Carryover	162,845	162,845	-	-	-	-	-	-	-	-	-	-	162,845
Revenue Requirement (RR)	579,593	432,431	400,679	420,865	468,618	484,980	439,787	423,090	449,317	427,220	407,353	452,278	5,386,211
Revenue Collections (RC)	536,823	475,740	473,327	400,780	400,206	406,732	455,735	450,676	403,116	411,923	451,431	519,690	5,386,181
Monthly RR - RC	42,770	(43,309)	(72,648)	20,085	68,412	78,248	(15,949)	(27,586)	46,201	15,297	(44,078)	(67,412)	
Balance (RR - RC + Cumulative CC)	42,770	(540)	(73,187)	(53,102)	15,310	93,558	77,610	50,023	96,224	111,521	67,443	31	

Carryover	2017 Tracker												
	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Annual Total
	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Legacy Projects	-	-	-	-	-	-	-	-	-	-	-	-	-
CAPX2020 - Brookings	252,099	251,536	250,973	250,416	249,853	249,275	248,720	248,201	247,694	247,187	246,680	246,173	2,988,808
CAPX2020 - Fargo	126,845	126,544	126,243	125,942	125,640	125,339	125,038	124,736	124,435	124,134	123,833	123,531	1,502,261
CAPX2020 - La Crosse Local	30,523	30,455	30,387	30,320	30,252	30,184	30,116	30,048	29,980	29,912	29,844	29,776	361,796
CAPX2020 - La Crosse MISO	67,654	67,462	67,269	67,077	66,885	66,693	66,501	66,308	66,116	65,924	65,732	65,540	799,160
CAPX2020 - La Crosse MISO - WI	83,751	83,551	83,350	83,149	82,949	82,748	82,547	82,347	82,146	81,945	81,745	81,544	991,770
Sioux Falls Northern	16,859	16,812	16,764	16,717	16,669	16,622	16,574	16,527	16,479	16,432	16,384	16,337	199,177
Chaska - Hwy 212 Conversion	9,342	9,320	9,298	9,275	9,253	9,230	9,208	9,186	9,163	9,141	9,119	9,096	110,632
Minn Valley	8,109	8,091	8,073	8,055	8,037	8,019	8,001	7,983	7,965	7,947	7,929	7,911	96,119
Maple River - Red River	4,388	4,887	5,344	5,652	5,883	6,522	7,011	7,001	6,986	6,970	6,953	6,936	74,534
Big Stone - Brookings	25,539	28,083	30,394	31,598	32,804	34,010	35,167	36,246	37,657	38,935	39,649	51,855	421,937
Lake Marion - Burnsville	4,805	4,795	4,784	4,774	4,763	4,753	4,742	4,732	4,721	4,711	4,700	4,690	56,968
Maple Lake - Annandale	1,273	1,269	1,265	1,262	1,258	1,254	1,250	1,247	1,243	1,239	1,235	1,232	15,026
Glencoe - Waconia	11,752	11,728	11,704	11,680	11,656	11,632	11,608	11,584	11,560	11,536	11,512	11,488	139,440
Bluff Creek - Westgate	11,706	11,670	11,635	11,599	11,564	11,530	11,496	11,461	11,425	11,389	11,354	11,318	138,148
Scott Cty 345 kV Expansion	13,860	13,821	13,782	13,743	13,703	13,664	13,625	13,586	13,547	13,507	13,468	13,429	163,735
Wilson Substation Conversion	-	-	-	-	-	-	-	-	-	-	-	-	-
Kohlman Lake-Goose Lake 2nd ckt	10,823	10,797	10,770	10,744	10,718	10,691	10,665	10,638	10,612	10,585	10,559	10,532	128,134
Prairie Sub Expansion	6,049	6,030	6,011	5,992	5,973	5,954	5,936	5,917	5,898	5,879	5,860	5,841	71,340
Black Dog - Savage	4,201	4,192	4,182	4,173	4,164	4,155	4,146	4,136	4,127	4,118	4,109	4,100	49,802
Chisago 2nd Transformer Addition	3,905	3,893	3,881	3,870	3,858	3,846	3,834	3,823	3,811	3,799	3,788	3,776	46,084
Franklin Transformer	3,266	3,259	3,253	3,246	3,239	3,232	3,226	3,219	3,212	3,206	3,199	3,192	38,749
Cass County SUB Expansion	2,550	2,544	2,539	2,534	2,528	2,523	2,518	2,513	2,507	2,502	2,497	2,492	30,247
New Prague Area	4,098	4,086	4,074	4,062	4,050	4,038	4,026	4,014	4,002	3,990	3,978	3,966	48,387
ELR - Breakers - NSPM	207	207	206	206	206	205	205	204	204	203	203	202	2,459
Minot Load Serving	1,658	2,060	2,461	2,886	3,580	4,380	5,479	6,930	8,315	9,764	11,511	13,274	72,297
NSPM Major Line Rebuild	2,938	2,930	2,923	2,915	2,908	2,900	2,892	2,887	2,884	2,881	2,879	2,876	34,813
Gleason Lake Sub	1,297	1,447	1,508	1,573	1,683	1,832	1,998	2,160	2,362	2,647	3,022	3,850	25,379
NSM0953 Galloping Mitigate SPK	3,967	3,956	3,945	3,934	3,922	3,911	3,900	3,889	3,878	3,870	3,868	3,868	46,908
S&E - NSP Line	5,804	5,799	5,793	5,787	5,781	5,784	5,807	5,841	5,914	6,026	6,139	6,252	70,728
ELR - Transformers - NSPM	2,673	2,665	2,657	2,649	2,641	2,632	2,624	2,616	2,608	2,600	2,592	2,584	31,540
Maple River 115kV MPC Interconnection	96	148	200	253	305	358	410	463	515	568	621	674	4,611
Dean Lake Substation	2,442	2,434	2,427	2,419	2,412	2,404	2,396	2,389	2,381	2,373	2,366	2,358	28,801
NSP Reloc B	2,055	2,178	2,270	2,350	2,419	2,454	2,458	2,464	2,391	2,313	2,307	2,302	27,962
Yankee Reactor	2,344	2,337	2,330	2,323	2,315	2,308	2,301	2,294	2,287	2,279	2,272	2,265	27,656
ELR - Relay - NSPM	586	584	583	581	580	579	577	576	575	573	572	571	6,937
RECB - 26 & 26(a)	(48,357)	(45,399)	(79,636)	(70,336)	(18,250)	(431)	(34,547)	(58,890)	(51,907)	(82,757)	(102,393)	(59,357)	(652,259)
Transmission Projects	681,109	686,172	653,642	663,419	716,201	735,231	702,457	679,274	687,695	658,330	640,084	696,471	8,200,086
Revenue Requirement in Base Rates	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(150,031)	(1,800,376)
TCR True-up Carryover	31	-	-	-	-	-	-	-	-	-	-	-	31
Revenue Requirement (RR)	531,108	536,141	503,611	513,388	566,170	585,200	552,425	529,243	537,664	508,298	490,052	546,440	6,399,740
Revenue Collections (RC)	639,182	554,549	559,305	478,836	479,473	483,623	542,015	536,049	479,479	490,293	537,304	619,579	6,399,690
Monthly RR - RC	(108,074)	(18,409)	(55,694)	34,551	86,697	101,577	10,410	(6,806)	58,184	18,005	(47,252)	(73,140)	
Balance (RR - RC + Cumulative CC)	(108,074)	(126,483)	(182,177)	(147,625)	(60,928)	40,649	51,059	44,253	102,437	120,442	73,190	51	

Universal Inputs						
Dates						
			Jan-14 Actual	Jan-15 Forecast	Jan-16 Forecast	Jan-17 Forecast
Depreciation						
Current						
	2007	Book Depreciation Life (yrs)	0.00	41.09	38.21	
	2007	Net Salvage %	0.00%	-19.49%	0.00%	
	2008	Book Depreciation Life (yrs)	0.00	44.57	38.22	
	2008	Net Salvage %	0.00%	-18.31%	0.00%	
	2009	Book Depreciation Life (yrs)	0.00	58.73	42.81	
	2009	Net Salvage %	0.00%	-18.16%	0.00%	
	2010	Book Depreciation Life (yrs)	0.00	58.40	42.77	
	2010	Net Salvage %	0.00%	-17.86%	0.00%	
	2011	Book Depreciation Life (yrs)	0.00	58.38	42.75	
	2011	Net Salvage %	0.00%	-17.78%	0.00%	
	2012	Book Depreciation Life (yrs)	0.00	57.94	42.78	
	2012	Net Salvage %	0.00%	-17.28%	0.00%	
	2013	Book Depreciation Life (yrs)	0.00	57.72	42.52	
	2013	Net Salvage %	0.00%	-17.20%	0.00%	
	2014	Book Depreciation Life (yrs)	0.00	57.72	42.52	
	2014	Net Salvage %	0.00%	-17.20%	0.00%	
	2015	Book Depreciation Life (yrs)	0.00	68.08	62.96	
	2015	Net Salvage %	0.00%	-32.54%	-9.54%	
	2016	Book Depreciation Life (yrs)	0.00	68.08	62.96	
	2016	Net Salvage %	0.00%	-32.54%	-9.54%	
Net Salvage %						
	Land		0.00%	0.00%	0.00%	0.00%
	Line		-17.20%	-32.54%	-32.54%	-32.54%
	Sub		0.00%	-9.54%	-9.54%	-9.54%
Book Depreciation Lives						
	Land		0.00	0.00	0.00	0.00
	Line		57.72	68.08	68.08	68.08
	Sub		42.52	62.96	62.96	62.96
Book Depreciation Rates						
	Land		0.00%	0.00%	0.00%	0.00%
	Line		2.03%	1.95%	1.95%	1.95%
	Sub		2.35%	1.74%	1.74%	1.74%
Book Depreciation Rate: Final Period						
	Land		0%			
	Line		100%			
	Sub		100%			
Tax Rates						
Income Tax Rates						
	State Income Tax Rate		4.3100%	4.3100%	4.3100%	4.3100%
	Federal Income Tax Rate		35.0000%	35.0000%	35.0000%	35.0000%
Composite Income Tax Rate						
	State Composite Income Tax Rate		37.8015%	37.8015%	37.8015%	37.8015%
	Company Composite Income Tax Rate		40.8029%	40.8097%	40.8097%	40.8097%
Tax Depreciation Schedule: MACRS						
	Annual					
	0		0.00%			
	1		5.00%			
	2		9.50%			
	3		8.55%			
	4		7.70%			
	5		6.93%			
	6		6.23%			
	7		5.90%			
	8		5.90%			
	9		5.91%			
	10		5.90%			
	11		5.91%			
	12		5.90%			
	13		5.91%			
	14		5.90%			
	15		5.91%			
	16		2.95%			
Tax Depreciation Schedule: MACRS						
	Mid-Quarter					
	Year	Q1	Q2	2010	Q3	Q4
	1	8.75%		6.25%	3.75%	1.25%
	2	9.13%		9.38%	9.63%	9.88%
	3	8.21%		8.44%	8.66%	8.89%
	4	7.39%		7.59%	7.80%	8.00%
	5	6.65%		6.83%	7.02%	7.20%
	6	5.99%		6.15%	6.31%	6.48%
	7	5.90%		5.91%	5.90%	5.90%
	8	5.91%		5.90%	5.90%	5.90%
	9	5.90%		5.91%	5.91%	5.90%
	10	5.91%		5.90%	5.90%	5.91%
	11	5.90%		5.91%	5.91%	5.90%
	12	5.91%		5.90%	5.90%	5.91%
	13	5.90%		5.91%	5.91%	5.90%
	14	5.91%		5.90%	5.90%	5.91%
	15	5.90%		5.91%	5.91%	5.90%
	16	0.74%		2.21%	3.69%	5.17%
Bonus Depreciation Rate						
		2014	50.00%			
		2015	50.00%			
Cap Structure (Based on Previous Year's Actual Structure)						
	Long Term Debt %		44.9600%	44.9600%	44.9600%	44.9600%
	Long Term Debt Cost (\$s as a % of total)		5.1400%	5.1400%	5.1400%	5.1400%
	Short Term Debt %		2.4800%	2.4800%	2.4800%	2.4800%
	Short Term Debt Cost (\$s as a % of total)		0.7500%	0.7500%	0.7500%	0.7500%
	Weighted Cost of Debt		2.33%	2.33%	2.33%	2.33%
	Common Stock %		52.56%	52.56%	52.56%	52.56%
	Common Stock Cost (\$s as a % of total)		10.00%	10.00%	10.25%	10.25%
	Preferred Stock %		0.00%	0.00%	0.00%	0.00%
	Preferred Stock Cost (\$s as a % of total)		0.00%	0.00%	0.00%	0.00%
	Weighted Cost of Equity		5.26%	5.26%	5.39%	5.39%
	Rate of Return		7.59%	7.59%	7.72%	7.72%
Property Tax Rates						
	Percent Taxable		100.00%	100.00%	100.00%	100.00%
	Asset Rate		1.811%	1.714%	1.714%	1.714%
	Property Tax Rate		1.811%	1.714%	1.714%	1.714%
OATT						
	Total Cost of Capital		7.5900%	7.5900%	7.7200%	7.7200%
	Equity Gross-Up Rate		60.7756%	60.7756%	60.7756%	60.7756%
	Equity Gross-Up		3.1968%	3.1968%	3.2758%	3.2758%
	Total Cost of Capital Incl Gross-Up for Taxes - Annual Rate		10.7868%	10.7868%	10.9958%	10.9958%
	Rate for Carrying Charge		0.8573%	0.8573%	0.8731%	0.8731%
	Annual OATT Credit Factor		19.90%	18.69%	20.99%	20.99%
Allocators						
	ND 12-month CP demand (Electric Demand)		6.3128%	6.1657%	6.2102%	6.2388%
	NSPM 36-month CP demand (Interchange Electric)		84.7923%	84.5789%	84.1349%	84.0028%
	Jurisdictional Allocator		5.3528%	5.2149%	5.2249%	5.2408%

OATT			
Description	Total 2016	Revenues Included in OATT credit	Revenues Excluded from OATT Credit
PTP - Firm	8,956,835		8,725,178
PTP - Non Firm	561,206		0
Network	29,470,550	29,470,550	764,679
Network - Whls	0	0	
Sch 1 - Sch, Sys Ctrl & D	1,154,635	1,154,635	
Sch 1 - Sch, Sys Ctrl & D - Whls	0	0	
Sch 2 - Reactive Supply	8,408,509	8,408,509	9,636,215
Sch 2 - Reactive Supply - Whls	0	0	
Sch 24 - Bal Auth	1,277,970	1,277,970	
Other RTO GFA Revenue	0	0	187,918
Trans Expansion Plan Att GG	91,523,134		37,440
Trans Expansion Plan Att MM Brookir	67,632,405		8,040,000
Trans Exp Plan - Sch 26A - Big Stone	0	0	58,998
Trans Exp Plan - Sch 26A - N LaCros	0	0	15,223
Joint Pricing Zone - GRE	35,938,887	35,938,887	46,268
Joint Pricing Zone - SMMPA	6,437,805	6,437,805	0
Joint Pricing Zone - MRES	3,942,746	3,942,746	
Sch 2 - Reactive Supply	126,983	126,983	
Firm Transmission	0	0	
Sch 1-Sch, Sys Ctrl & D	0	0	
Sch 2 - Reactive Supply	0	0	
MISO Schedule 10 Passthrough	0	0	
Facilities	46,866		46,866
Facilities	188,010		188,010
Contracts - WPPI	37,440		37,440
Contracts - UPA	0		0
Contracts - UND	61,499		61,499
Contracts - Granite Falls	15,838		15,838
Contracts - EGF	49,709		49,709
GRE Cr Lk Facilities	212,410	212,410	
GRE 500k/ tsmn O&M	46,573	46,573	
Marshall TOPS	127,208	127,208	
Sch 14 Req Thru & Out-	0		
Sch 26 Sub-Req Rate Ad	0		60,979,512
Sch 26a-MVP NSP 1203	0		52,287,847
Sch 37 Trans Exp Plan	0		1,264,109
Sch 38 Trans Exp Plan	0		992,430
Trans Expansion Plan - Whls	0		0
FERC Assmt Passthrough	0		0
RTO-Passthrough Rev -	0		0
Totals	256,217,218	87,144,276	143,035,818
		Revenues Included in OATT Credit	87,144,276
		Total Gross (Attachment O) Tran Rev Req	415,209,195
		2016 OATT Adjustment Factor	20.99%
NSP Revenue Credits for FERC Account 456			
Description	Total 2015	Revenues Included in OATT credit	Revenues Excluded from OATT Credit
PTP - Firm	8,038,450		8,038,450
PTP - Non Firm	811,113		811,113
Network	23,907,580	23,907,580	
Network - Whls	0	0	
Sch 1 - Sch, Sys Ctrl & D	1,049,508	1,049,508	
Sch 1 - Sch, Sys Ctrl & D - Whls	0	0	
Sch 2 - Reactive Supply	9,052,265	9,052,265	
Sch 2 - Reactive Supply - Whls	0	0	
Sch 24 - Bal Auth	2,026,048	2,026,048	
Other RTO GFA Revenue	0	0	
Trans Expansion Plan Att GG	73,650,766		73,650,766
Trans Expansion Plan Att MM Brookings	62,778,910		62,778,910
Trans Expansion Plan Att MM Big Stone	180,145		180,145
Joint Pricing Zone - GRE	31,276,514	31,276,514	
Joint Pricing Zone - SMMPA	5,934,739	5,934,739	
Sch 2 - Reactive Supply	126,983	126,983	
Firm Transmission	6,288,983		6,288,983
Sch 1-Sch, Sys Ctrl & D	146,456	146,456	
Sch 2 - Reactive Supply	8,421	8,421	
MISO Schedule 10 Passthrough	236,176		236,176
Facilities	46,866		46,866
Facilities	184,597		184,597
Contracts - WPPI	37,440		37,440
Contracts - UPA	2,680,000		2,680,000
Contracts - UND	57,852		57,852
Contracts - Granite Falls	15,527		15,527
Contracts - EGF	46,268		46,268
GRE Cr Lk Facilities	212,410	212,410	
GRE 500k/ tsmn O&M	37,801	37,801	
Marshall TOPS	124,105	124,105	
Totals	228,956,022	73,528,512	155,427,510
		Revenues Included in OATT Credit	73,528,512
		Total Gross (Attachment O) Tran Rev Req	393,388,681
		2015 OATT Adjustment Factor	18.69%
NSP Revenue Credits for FERC Account 456			
Description	Total 2014	Revenues Included in OATT credit	Revenues Excluded from OATT Credit
PTP - Firm	8,637,794		8,637,794
PTP - Non Firm	758,682		758,682
Network	20,108,468	20,108,468	
Network - Whls	0	0	
Sch 1 - Sch, Sys Ctrl & D	896,679	896,679	
Sch 1 - Sch, Sys Ctrl & D - Whls	0	0	
Sch 2 - Reactive Supply	8,902,392	8,902,392	
Sch 2 - Reactive Supply - Whls	0	0	
Sch 24 - Bal Auth	1,746,037	1,746,037	
Other RTO GFA Revenue	134,889	134,889	
Trans Expansion Plan Att GG	62,606,771		62,606,771
Trans Expansion Plan Att MM Brookings	52,936,599		52,936,599
Trans Expansion Plan Att MM Big Stone	0		0
Joint Pricing Zone - GRE	33,159,403	33,159,403	
Joint Pricing Zone - SMMPA	6,030,827	6,030,827	
Sch 2 - Reactive Supply	126,983	126,983	
Firm Transmission	9,697,117		9,697,117
Sch 1-Sch, Sys Ctrl & D	213,071	213,071	
Sch 2 - Reactive Supply	135,646	135,646	
MISO Schedule 10 Passthrough	305,800		305,800
Facilities	46,866		46,866
Facilities	185,827		185,827
Contracts - WPPI	37,440		37,440
Contracts - UPA	8,040,000		8,040,000
Contracts - UND	56,816		56,816
Contracts - Granite Falls	15,223		15,223
Contracts - EGF	46,268		46,268
GRE Cr Lk Facilities	212,410	212,410	
GRE 500k/ tsmn O&M	37,801	37,801	
Marshall TOPS	99,284	99,284	
Totals	215,175,093	71,454,395	143,720,698
		Revenues Included in OATT Credit	71,454,395
		Total Gross (Attachment O) Tran Rev Req	359,014,933
		2014 OATT Adjustment Factor	19.90%

Regional Expansion Criteria and Benefits (RECB)	Jan-14 Actual	Feb-14 Actual	Mar-14 Actual	Apr-14 Actual	May-14 Actual	Jun-14 Actual	Jul-14 Actual	Aug-14 Actual	Sep-14 Actual	Oct-14 Actual	Nov-14 Actual	Dec-14 Actual	2014 Actual
Revenue													
Schedule 26	5,545,835	4,889,369	5,120,435	4,514,251	4,754,659	6,141,202	6,387,845	6,087,120	5,682,181	4,655,480	6,132,663	5,216,379	65,127,417
Schedule 26(a)	4,435,941	3,908,064	4,152,363	3,719,190	3,899,844	4,095,728	4,635,458	4,596,442	4,045,562	3,965,102	3,954,306	3,525,516	48,933,517
Total Revenue	9,981,776	8,797,433	9,272,798	8,233,441	8,654,503	10,236,929	11,023,303	10,683,562	9,727,743	8,620,583	10,086,969	8,741,894	114,060,934
Expense													
Schedule 26	4,966,410	4,255,830	4,440,339	3,932,451	5,113,258	5,066,056	6,235,165	5,556,824	5,088,687	3,995,908	4,396,895	4,683,086	57,730,909
Schedule 26(a)	1,531,859	1,351,839	1,466,063	1,375,206	1,408,286	1,482,978	1,717,319	1,746,555	1,451,547	1,398,959	1,375,544	1,226,535	17,532,690
Total Expense	6,498,269	5,607,670	5,906,402	5,307,656	6,521,544	6,549,034	7,952,484	7,303,380	6,540,234	5,394,867	5,772,439	5,909,621	75,263,599
Total	(3,483,507)	(3,189,763)	(3,366,396)	(2,925,785)	(2,132,959)	(3,687,896)	(3,070,819)	(3,380,182)	(3,187,509)	(3,225,716)	(4,314,530)	(2,832,274)	(38,797,335)
Demand Allocator - State of ND Jur.	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%
RECB Revenue Requirement	(186,464)	(170,741)	(180,195)	(156,610)	(114,172)	(197,405)	(164,374)	(180,933)	(170,620)	(172,665)	(230,947)	(151,605)	(2,076,731)
RECB in Base Rates													
Net RECB Revenue Requirements	(186,464)	(170,741)	(180,195)	(156,610)	(114,172)	(197,405)	(164,374)	(180,933)	(170,620)	(172,665)	(230,947)	(151,605)	(2,076,731)

Regional Expansion Criteria and Benefits (RECB)	Jan-15 Actual	Feb-15 Actual	Mar-15 Actual	Apr-15 Actual	May-15 Actual	Jun-15 Actual	Jul-15 Actual	Aug-15 Actual	Sep-15 Forecast	Oct-15 Forecast	Nov-15 Forecast	Dec-15 Forecast	2015 Forecast
Revenue													
Schedule 26	6,211,131	5,551,066	5,039,524	5,431,295	5,443,990	6,118,289	7,124,823	7,112,593	6,361,555	5,243,117	5,075,478	5,398,769	70,111,619
Schedule 26(a)	5,229,225	4,641,332	4,716,403	4,046,105	4,336,571	4,760,734	4,849,856	5,051,876	4,197,975	4,076,900	4,098,811	4,216,489	54,222,077
Total Revenue	11,440,356	10,192,398	9,755,926	9,477,401	9,780,561	10,879,023	11,974,679	12,164,258	10,559,531	9,320,017	9,174,289	9,615,259	124,333,696
Expense													
Schedule 26	5,623,119	4,956,186	5,255,382	4,536,449	5,434,777	6,344,545	7,062,587	7,253,183	5,996,206	4,394,862	4,572,853	4,857,265	66,287,417
Schedule 26(a)	2,596,867	2,266,781	2,382,129	2,179,773	2,305,908	2,599,851	2,815,933	2,759,707	1,827,198	1,776,571	1,795,593	1,810,179	27,116,288
Total Expense	8,219,986	7,222,967	7,637,511	6,716,222	7,740,685	8,944,196	9,878,520	10,012,890	7,823,405	6,171,434	6,368,446	6,667,443	93,403,705
Total	(3,220,370)	(2,969,431)	(2,118,415)	(2,761,179)	(2,039,876)	(1,934,827)	(2,096,159)	(2,151,369)	(2,736,126)	(3,148,583)	(2,805,843)	(2,947,815)	(30,929,991)
Demand Allocator - State of ND Jur.	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%
RECB Revenue Requirement	(167,938)	(154,852)	(110,473)	(143,992)	(106,377)	(100,899)	(109,312)	(112,191)	(142,686)	(164,195)	(146,321)	(153,725)	(1,612,962)
RECB in Base Rates													
Net RECB Revenue Requirements	(167,938)	(154,852)	(110,473)	(143,992)	(106,377)	(100,899)	(109,312)	(112,191)	(142,686)	(164,195)	(146,321)	(153,725)	(1,612,962)

Regional Expansion Criteria and Benefits (RECB)	Jan-16 Forecast	Feb-16 Forecast	Mar-16 Forecast	Apr-16 Forecast	May-16 Forecast	Jun-16 Forecast	Jul-16 Forecast	Aug-16 Forecast	Sep-16 Forecast	Oct-16 Forecast	Nov-16 Forecast	Dec-16 Forecast	2016 Forecast
Revenue													
Schedule 26	6,621,692	6,526,403	6,972,059	6,354,350	7,075,701	8,063,367	9,500,792	9,370,587	8,397,502	6,848,973	7,279,516	7,274,374	90,285,317
Schedule 26(a)	5,309,971	4,687,590	4,791,963	4,255,947	4,588,654	5,019,943	5,783,275	5,492,878	4,611,824	4,486,467	4,599,849	4,403,226	58,031,388
Total Revenue	11,931,663	11,213,993	11,764,022	10,610,297	11,664,355	13,083,310	15,284,067	14,863,265	13,009,327	11,335,441	11,879,365	11,677,600	148,316,706
Expense													
Schedule 26	6,602,711	6,450,896	6,254,108	5,687,931	7,414,155	8,850,357	9,590,027	9,071,196	8,119,270	5,993,213	6,101,639	6,713,537	86,849,041
Schedule 26(a)	3,071,332	2,733,432	2,798,848	2,539,400	2,732,652	2,966,192	3,504,633	3,245,826	2,745,153	2,668,039	2,697,013	2,719,229	34,421,748
Total Expense	9,674,043	9,184,328	9,052,956	8,227,331	10,146,807	11,816,548	13,094,660	12,317,023	10,864,424	8,661,253	8,798,652	9,432,766	121,270,789
Total	(2,257,620)	(2,029,665)	(2,711,066)	(2,382,966)	(1,517,548)	(1,266,762)	(2,189,407)	(2,546,243)	(2,144,903)	(2,674,188)	(3,080,713)	(2,244,835)	(27,045,917)
Demand Allocator - State of ND Jur.	5.22%	5.22%	5.22%	5.22%	5.22%	5.22%	5.22%	5.22%	5.22%	5.22%	5.22%	5.22%	5.22%
RECB Revenue Requirement	(117,959)	(106,049)	(141,652)	(124,509)	(79,291)	(66,188)	(114,395)	(133,040)	(112,070)	(139,725)	(160,966)	(117,291)	(1,413,134)
RECB in Base Rates													
Net RECB Revenue Requirements	(117,959)	(106,049)	(141,652)	(124,509)	(79,291)	(66,188)	(114,395)	(133,040)	(112,070)	(139,725)	(160,966)	(117,291)	(1,413,134)

Regional Expansion Criteria and Benefits (RECB)													
	Jan-17 Forecast	Feb-17 Forecast	Mar-17 Forecast	Apr-17 Forecast	May-17 Forecast	Jun-17 Forecast	Jul-17 Forecast	Aug-17 Forecast	Sep-17 Forecast	Oct-17 Forecast	Nov-17 Forecast	Dec-17 Forecast	2017 Forecast
Revenue													
Schedule 26	6,555,629	6,462,432	6,898,306	6,294,155	6,999,672	7,965,659	9,371,532	9,244,185	8,292,460	6,777,922	7,199,014	7,193,985	89,254,852
Schedule 26(a)	5,364,350	4,779,171	4,877,305	4,373,330	4,686,149	5,051,658	5,809,362	5,536,136	4,707,935	4,590,071	4,696,675	4,511,805	59,023,947
Total Revenue	11,919,979	11,241,603	11,775,611	10,667,485	11,685,822	13,057,317	15,180,894	14,780,321	13,000,395	11,367,992	11,895,689	11,705,790	148,278,899
Expense													
Schedule 26	6,597,750	6,453,938	6,242,106	5,678,534	7,417,284	8,798,355	9,509,094	9,010,222	8,071,967	5,960,006	6,072,041	6,671,888	86,483,187
Schedule 26(a)	4,399,512	3,921,404	4,013,963	3,646,859	3,920,299	4,250,745	5,012,608	4,646,411	3,937,989	3,828,877	3,869,873	3,901,307	49,349,847
Total Expense	10,997,262	10,375,342	10,256,069	9,325,394	11,337,584	13,049,100	14,521,702	13,656,633	12,009,956	9,788,883	9,941,914	10,573,196	135,833,034
Total	(922,717)	(866,261)	(1,519,542)	(1,342,092)	(348,238)	(8,217)	(659,192)	(1,123,687)	(990,439)	(1,579,109)	(1,953,775)	(1,132,594)	(12,445,865)
Demand Allocator - State of ND Jur.	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%
RECB Revenue Requirement	(48,357)	(45,399)	(79,636)	(70,336)	(18,250)	(431)	(34,547)	(58,890)	(51,907)	(82,757)	(102,393)	(59,357)	(652,259)
RECB in Base Rates													
Net RECB Revenue Requirements	(48,357)	(45,399)	(79,636)	(70,336)	(18,250)	(431)	(34,547)	(58,890)	(51,907)	(82,757)	(102,393)	(59,357)	(652,259)

Non-Legislative

NORTH DAKOTA ELECTRIC RATE BOOK - NDPSC NO. 2

TRANSMISSION COST RECOVERY RIDER

Section No. 5

~~3rd~~^{4th} Revised Sheet No. 86

APPLICATION

Applicable to bills for electric service provided under the Company's retail rate schedules.

RIDER

There will be included on each customer's monthly bill a Transmission Cost Recovery (TCR) charge for purposes of recovering transmission capital and operating costs not presently reflected in base retail rates. The TCR charge shall be determined by multiplying a customer's monthly billed kWh for electric service by the current TCR rate. The TCR charge shall be calculated prior to the application of any city surcharges and/or sales tax.

DETERMINATION OF TCR RATE

The TCR rate is calculated by dividing the forecasted balance of the TCR Tracker Account by the forecasted retail sales. The TCR rate shall be rounded to the nearest \$0.000001 per kWh.

Transmission costs recoverable under this Rider include (i) the annual revenue requirements associated with electric transmission facilities eligible for recovery under NDCC 49.05.04.1, and (ii) federally regulated costs charged to or incurred by the Company to increase regional transmission capacity or reliability. A standardized forecast model will be used to calculate the total revenue requirements for eligible transmission facilities affecting the recovery period. Forecasted retail sales shall be the estimated total retail electric sales for the applicable recovery period.

The TCR rate will be determined annually for each upcoming calendar year recovery period through a TCR rate adjustment application to the North Dakota Public Service Commission.

The TCR rate will apply to monthly billed kWh rendered on and after January 1st of the recovery year. The present TCR rate is:

All Customer Classes ~~\$0.002505~~\$0.002332 per kWh

RC

All approved costs appropriately charged to the TCR Tracker Account shall be eligible for recovery through this Rider, and all revenues recovered through the Rider shall be credited to the TCR Tracker Account.

TRUE-UP

For each 12-month period ending December 31, a true-up adjustment to the Tracker Account will be calculated reflecting the difference between actual TCR Rider revenue and the corresponding transmission costs (revenue requirements) for the recovery period. The true-up amount shall be recorded by May 1 of the following calendar year and will be included in the calculation of the TCR rate effective for the next calendar year recovery period.

For example, Year 1 actual Rider revenue will be compared to actual revenue requirements for the same period and the difference recorded as an adjustment to the Tracker Account on or before May 1 of Year 2. This difference would then be included in the calculation of the new TCR rate (application to be filed in Year 2) effective January 1 of Year 3.

Date Filed: 07-22-1410-01-15 By: Christopher B. Clark Effective Date: 04-01-15
President, ~~and CEO of~~ Northern States Power Company, a Minnesota corporation
Case No. PU-14-644PU-15- Order Date: 12-17-14

Legislative

NORTH DAKOTA ELECTRIC RATE BOOK - NDPSC NO. 2

TRANSMISSION COST RECOVERY RIDER

Section No. 5
4th Revised Sheet No. 86

APPLICATION

Applicable to bills for electric service provided under the Company's retail rate schedules.

RIDER

There will be included on each customer's monthly bill a Transmission Cost Recovery (TCR) charge for purposes of recovering transmission capital and operating costs not presently reflected in base retail rates. The TCR charge shall be determined by multiplying a customer's monthly billed kWh for electric service by the current TCR rate. The TCR charge shall be calculated prior to the application of any city surcharges and/or sales tax.

DETERMINATION OF TCR RATE

The TCR rate is calculated by dividing the forecasted balance of the TCR Tracker Account by the forecasted retail sales. The TCR rate shall be rounded to the nearest \$0.000001 per kWh.

Transmission costs recoverable under this Rider include (i) the annual revenue requirements associated with electric transmission facilities eligible for recovery under NDCC 49.05.04.1, and (ii) federally regulated costs charged to or incurred by the Company to increase regional transmission capacity or reliability. A standardized forecast model will be used to calculate the total revenue requirements for eligible transmission facilities affecting the recovery period. Forecasted retail sales shall be the estimated total retail electric sales for the applicable recovery period.

The TCR rate will be determined annually for each upcoming calendar year recovery period through a TCR rate adjustment application to the North Dakota Public Service Commission.

The TCR rate will apply to monthly billed kWh rendered on and after January 1st of the recovery year. The present TCR rate is:

All Customer Classes	\$0.002332 per kWh
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C

All approved costs appropriately charged to the TCR Tracker Account shall be eligible for recovery through this Rider, and all revenues recovered through the Rider shall be credited to the TCR Tracker Account.

TRUE-UP

For each 12-month period ending December 31, a true-up adjustment to the Tracker Account will be calculated reflecting the difference between actual TCR Rider revenue and the corresponding transmission costs (revenue requirements) for the recovery period. The true-up amount shall be recorded by May 1 of the following calendar year and will be included in the calculation of the TCR rate effective for the next calendar year recovery period.

For example, Year 1 actual Rider revenue will be compared to actual revenue requirements for the same period and the difference recorded as an adjustment to the Tracker Account on or before May 1 of Year 2. This difference would then be included in the calculation of the new TCR rate (application to be filed in Year 2) effective January 1 of Year 3.

Date Filed: 10-01-15

By: Christopher B. Clark

Effective Date:

President, Northern States Power Company, a Minnesota corporation

Case No. PU-15-

Order Date: