414 Nicollet Mall
Minneapolis, MN 55401

November 8, 2017

—Via Electronic Filing—

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101

RE: PETITION
TRANSMISSION COST RECOVERY RIDER
DOCKET NO. E002/M-17-____

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Petition for approval of 2017-2018 Transmission Cost Recovery Rider revenue requirements.

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document, and served copies of the summary on the parties on the attached service list.

If you have any questions regarding this filing please contact Rebecca Eilers at (612) 330-5570 or rebecca.d.eilers@xcelenergy.com or me at (612) 330-5941 or holly.r.hinman@xcelenergy.com.

Sincerely,

/s/

HOLLY HINMAN
REGULATORY MANAGER

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie Sieben	Commissioner
John Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE TRANSMISSION COST RECOVERY RIDER REVENUE REQUIREMENTS FOR 2017 AND 2018, AND REVISED ADJUSTMENT FACTORS

DOCKET NO. E002/M-17-___

PETITION AND COMPLIANCE FILING

OVERVIEW

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Petition requesting approval of the Transmission Cost Recovery (TCR) Rider combined revenue requirements for 2017 and 2018 of $109.5 million and the corresponding TCR adjustment factors.

In accordance with the Settlement approved by the Commission in the Company's most recent electric rate case, the three CapX2020 transmission projects currently included in the TCR Rider remain in the rider through the multi-year rate plan period (2016 through 2019) in lieu of rolling the projects into base rates.[1] We do not propose to recover costs of any new transmission projects in the TCR Rider at this time. However, we propose to recover costs related to one grid modernization project pursuant to an amendment made to the Transmission Statute[2] during the 2015 legislative session that allows for recovery of distribution-grid modernization projects certified by the Commission. The Advanced Distribution Management System (ADMS) project was certified by the Commission in the 2015 Biennial Distribution-Grid Modernization Report proceeding.[3] In support of cost recovery of this project,

[1] Docket No. E002/GR-15-826; FINDINGS OF FACT, CONCLUSIONS, AND ORDER (June 12, 2017).
[2] Minn. Stat. § 216B.16, Subd. 7b
[3] Docket No. E002/M-15-962; ORDER CERTIFYING ADVANCED DISTRIBUTION-MANAGEMENT SYSTEM (ADMS) PROJECT UNDER MINN. STAT. § 216B.2425 AND REQUIRING DISTRIBUTION STUDY (June 28, 2016).

our Petition details the need for ADMS, the process for selecting a vendor, the customer benefits of the ADMS, and the project budget and budgeting process.

Our Petition also discusses the appropriate Return on Equity (ROE) for calculating a rider's revenue requirements.

If our Petition is approved as proposed, the average residential customer using 675 kWh of electricity per month would see an increase on their bill of approximately $0.77 per month compared to the current TCR residential Adjustment Factor. The primary drivers to the increase in the TCR revenue requirements are:

- Approximately $16 million lower net revenue from MISO regional sharing;
- Approximately $12 million due to the completion of Big Stone-Brookings and La Crosse-Madison lines; and
- Approximately $3.6 million due to the addition of the ADMS grid modernization project.

While the revenue requirements increase due to several projects' completion, we note that the projects were completed on time and below the capital expenditures forecasted in our 2015 TCR. In particular:

- the Big Stone-Brookings project expenditure forecast is down 18 percent since our last filing;
- the CAPX2020 – La Crosse Local project is down 15 percent; and
- the La Crosse – Madison project is down 11 percent.

Our Petition is structured as follows:

- Background;
- TCR Eligible Projects, including the addition of the ADMS project;
- Return on Equity
- 2017 and 2018 TCR Revenue Requirements and Adjustment Factors;
- TCR Variance Analysis Report;
- Removal of Internal Labor Costs;
- 2016 True-Up Report and Tracker Balance; and
- Proposed Tariff Sheet and Customer Notice.

I. SUMMARY OF FILING

Pursuant to Minn. Rule 7829.1300, Subp. 1, a one paragraph summary of our filing accompanies this Petition.

II. SERVICE ON OTHER PARTIES

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document with the Commission, and copies of the summary have been served on the parties on the attached service list.

III. GENERAL FILING INFORMATION

Pursuant to Minn. R. 7829.1300, subp. 3, the Company provides the following information.

A. Name, Address, and Telephone Number of Utility

Northern States Power Company, doing business as:
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500

B. Name, Address, and Telephone Number of Utility Attorney

Amanda Rome
Lead Assistant General Counsel
Xcel Energy
414 Nicollet Mall, 401 - 8th Floor
Minneapolis, MN 55401
(612) 215-5331

C. Date of Filing and Proposed Effective Date of Rates

The date of this filing is November 8, 2017. The Company proposes the updated TCR Adjustment Factors be included in the Resource Adjustment line on the Company's retail electric billing rates effective the first day of the month following the Commission's Order approving this Petition. For illustrative purposes, we have calculated the proposed TCR rate to be effective January 1, 2018, with recovery of the proposed revenue requirements to occur during the following 12 months. We propose to recalculate the Adjustment Factors for implementation in compliance based on the timing of the Commission's decision.

D. Statutes Controlling Schedule for Processing the Filing

Minn. Stat. § 216B.16 allows a utility to place a rate change in effect upon 60-days' notice to the Commission.[4] Minn. Stat. § 216B.16, Subd. 7b (the Transmission Statute) allows for recovery, through an automatic adjustment mechanism of charges, the Minnesota jurisdictional costs of certain new transmission facilities, facilities and planning investments that support grid modernization efforts, and certain Midcontinent Independent Transmission System Operator (MISO) charges associated with regionally planned transmission projects. Minn. Stat. § 216B.1645 (the Renewable Energy Statute) allows for recovery, through an automatic adjustment mechanism, of all investments or expenditures entered into by a public utility in connection with satisfying renewable energy mandates of the Legislature. The Commission has jurisdiction over the accounting practices of public utilities pursuant to Minn. Stat. § 216B.10.

Since no determination of Xcel Energy's general revenue requirement is necessary, this filing falls within the definition of a "miscellaneous filing" under Minn. Rule 7829.0100, Subp. 11. Pursuant to Minn. Rule 7829.1400, initial comments on a miscellaneous filing are due within 30 days of filing, with replies due 10 days thereafter.

E. Utility Employee Responsible for Filing

Holly Hinman
Regulatory Manager
Xcel Energy
414 Nicollet Mall, 401 - 7th Floor
Minneapolis, MN 55401
(612) 330-5941

IV. MISCELLANEOUS INFORMATION

The Company will serve a copy of the Petition summary on those persons on the electric utility general service list. Pursuant to Minn. Rule 7829.0700, we request that the following persons be placed on the Commission's official service list for this matter:

[4] We note that 60 days from the date of this Petition is January 7, 2018.

Amanda Rome
Lead Assistant General Counsel
Xcel Energy
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Carl Cronin
Regulatory Administrator
Xcel Energy
414 Nicollet Mall, 401 - 7th Floor
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Any information requests in this proceeding should be submitted to Mr. Cronin at the Regulatory Records email address above.

V. BACKGROUND

The 1997 Legislature enacted the Renewable Energy Statute, authorizing the Commission to approve a tariff mechanism for an automatic annual adjustment of charges for costs associated with utility investments or costs to comply with renewable energy mandates. The 2005 Legislature enacted the Transmission Statute, authorizing the Commission to approve a tariff mechanism for an automatic adjustment of charges for costs associated with eligible utility investments in transmission facilities, and in 2008 amended this statute to allow inclusion of the costs of certain regional transmission facilities as determined by MISO.

The Commission's November 20, 2006 Order in Docket No. E002/M-06-1103 approved the Company's TCR Rider tariff, which combined recovery of eligible projects under the Renewable Statute and the Transmission Statute in one annual automatic adjustment mechanism.

Since 2006, the Company's TCR Rider mechanism has been modified several times to allow recovery of additional costs subsequently authorized by the Minnesota Legislature. The Commission's March 20, 2008 Order in Docket No. E002/M-07-1156 approved recovery of greenhouse gas infrastructure costs incurred for the replacement of circuit breakers that contain sulfur hexafluoride (SF6). The Commission's June 25, 2009 Order in Docket No. E002/M-08-1284 approved recovery of Regional Expansion Criteria and Benefits (RECB) revenues and costs. In 2013, the Transmission Statute was modified to allow TCR Rider eligibility of projects located in other states that have been approved by the regulatory commission of the state in which the new transmission facilities are to be constructed and determined by MISO to benefit the utility or integrated transmission system.

During the 2015 legislative session, the Transmission Statute was further modified to allow for the cost recovery of facilities and planning investments that support grid modernization efforts. Such projects must be certified by the Commission under

Minn. Stat. § 216B.2425 in order to be eligible for rider recovery. Our first Biennial Grid Modernization Report was submitted on November 1, 2015 in accordance with Minn. Stat. § 216B.2425, subd. 2. The Commission certified the Company's ADMS grid modernization project through the Biennial Report proceeding in its June 28, 2016 Order in Docket No. E002/M-15-962. This is our first TCR rider proceeding filed subsequent to that Order, so we request cost recovery of the certified ADMS grid modernization project in this Petition.

In the past, we have categorized all reports and calculations associated with project costs and revenue requirements in three groups: (1) Transmission Statute projects; (2) Renewable Statute projects; and (3) Greenhouse Gas projects. In this filing, we add a fourth group for Distribution-Grid Modernization projects. While those projects are authorized for recovery under the Transmission Statute, we believe the type of project is distinct from transmission projects and the additional grouping can aid in review. Although we track costs separately by statute, it has been our past practice in TCR petitions to request approval for recovery of the total costs under a single recovery mechanism, the TCR Rider. This specific TCR Petition includes only Transmission Statute projects and Grid Modernization-Distribution projects.

With the filing of this TCR Petition, we propose to set new TCR Adjustment Factors beginning January 2, 2018. As has been the case in past TCR dockets, the Company will true-up the difference between the revenues we will continue to collect under the current TCR Adjustment Factors with the revenue requirements the Commission approves in this TCR proceeding.

VI. ELIGIBLE PROJECTS

We provide the following required information to support designation of eligibility for TCR-eligible transmission projects:

- Attachments 1 and 1A: Descriptions of Eligible Projects;
- Attachment 2: the Implementation Schedule for projects eligible under the Transmission Statute; and
- Attachment 3: Total TCR Project Capital Expenditures.

A. Projects Previously Deemed Eligible for TCR Recovery[5]

In its Order dated April 27, 2010 in Docket No. E002/M-09-1048, the Commission approved TCR Rider cost recovery for the following eligible projects under Minn. Stat. § 216B.16, Subd. 7b:

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

In its Order dated February 7, 2014 in Docket No. E002/M-12-50, the Commission approved TCR Rider cost recovery for the following eligible project under Minn. Stat. § 216B.16, Subd. 7b:

- CapX2020 Brookings – Twin Cities

In its Order dated January 17, 2017 in Docket No. E002/M-15-891, the Commission approved TCR Rider cost recovery for the following eligible projects under Minn. Stat. § 216B.16, Subd. 7b:

- Badger – Coulee (also known as La Crosse – Madison)
- CapX2020 Big Stone – Brookings

In its FINDINGS OF FACT, CONCLUSIONS, AND ORDER dated June 12, 2017 in Docket No. E002/GR-15-826, the Commission approved a Settlement in our electric rate case proceeding wherein parties agreed that the three CapX2020 transmission projects currently included in the TCR Rider, Fargo – Twin Cities, the three La Crosse segments, and Brookings – Twin Cities, are allowed to remain in the rider through the multi-year rate plan period (2016 through 2019) in lieu of rolling the projects into base rates. No costs associated with the above-noted projects are currently recovered through base rates.[6]

B. New Projects Eligible for TCR Recovery

The Company requests Commission approval of the following new project as eligible for TCR Rider recovery:

- ADMS grid modernization project

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[5] We note that while projects can be eligible for TCR cost recovery under Minn. Stat. § 216B.1645, none of the projects currently included under the rider are eligible under that statute.

[6] Final rates were implemented on October 1, 2017 as approved in the Commission's September 29, 2017 Order in Docket No. E002/GR-15-826.

In its June 28, 2016 Order in the 2015 Biennial Distribution-Grid Modernization Report, the Commission clarified that its decision to certify the ADMS project does not imply any decision regarding recovery of the project's costs, only that the decision to certify represents a finding that the project is consistent with the requirements of Minn. Stat. § 216B.2425. In order to establish the prudence of the ADMS project costs, this Petition provides extensive details regarding the project's history, background, budget and implementation plan. Attachments 1A and 4B include these details to provide the Commission additional information to support cost recovery through the TCR.

In summary, ADMS is one of the necessary foundational elements for grid modernization. In particular, ADMS incorporates Distribution Supervisory Control and Data Acquisition (D-SCADA) measurements and smart grid technology as a network to provide load flow calculations everywhere on the grid that accurately adjusts with enhancements or outages. This allows the Company to improve the monitoring and control of load flow from substations to the edge of the grid.

The total Xcel Energy Company-wide ADMS investment is estimated to be approximately $208.9 million over several years. The State of Minnesota portion is approximately $70 million, with an expected in-service date of 2020. We have included in this request the O&M costs related to the software maintenance agreement which are firm, external costs related to grid modernization necessary for the functionality of this project. As we describe in more detail in Attachment 1A, we engaged in an RFP process to find a vendor suited to our needs, and worked closely with Schneider Electric, our chosen vendor, to manage costs while not sacrificing the quality of the installed product.

C. RES Study Deferred Costs

Minn. Stat. § 216B.1691, Sec. 2 required Xcel Energy to participate in a multi-year joint study with other Minnesota electric utilities to evaluate the impact of the Renewable Energy Standard (RES) on the state's transmission system and identify the transmission projects necessary to support the renewable generation additions that will result from Minnesota's Renewable Energy Standards. The RES statute allows for the recovery of transmission study costs. In its March 20, 2008 Order in Docket No. E002/M-07-1156, the Commission approved recovery of the RES study costs through the annual TCR filing submitted after the Company has filed an application for a certificate of need or for certification as a priority project under Minn. Stat. § 216B.2425 for the new transmission facilities identified in the studies. The Commission approved the Company's request for deferred accounting treatment of the costs associated with the RES Study in the same Order. At the time, we estimated the Minnesota jurisdictional cost for the RES study to be $390,198.

In the Biennial Transmission Projects Report filed with the Commission on November 2, 2009 in Docket No. E999/M-09-602, the Minnesota Transmission Owners (MTO) reported on the completed RES Study. The RES Study identified the La Crosse – Madison 345 kV line as the appropriate transmission solution to facilitate the Twin Cities' access to additional energy sources during a sudden loss of wind generation. Traveling through an area relatively devoid of high voltage transmission support, and tying together two largely separate transmission systems, the La Crosse – Madison 345 kV line was also shown to significantly increase generation delivery capability.

While the wording of the Order indicates that cost recovery could be triggered upon the filing of the Certificate of Need for any projects identified in the RES study, the only project identified was a project located in Wisconsin. Because the amendment to the statute authorizing out-of-state transmission projects had not yet been tested, we waited for approval of that project's inclusion in the TCR before requesting recovery of the deferred RES Study costs. The Commission approved the inclusion of the La Crosse – Madison project through its January 17, 2017 Order in Docket No. E002/M-15-891.

The final deferred cost of the RES Study is $298,509. We have included this amount in the proposed 2018 revenue requirement. Please see Attachment 4, line 10.

VII. RETURN ON EQUITY

The Settlement in our recently-concluded electric rate case allows the Company to represent its authorized ROE as 9.20 percent for settlement purposes in the rate case proceeding. The Company acknowledges that the settled ROE is non-binding for riders, and so we present evidence and propose a new ROE for use in this TCR Rider proceeding.

The Company retained an independent expert, Concentric Energy Advisors (Concentric), to perform an assessment of the appropriateness of the Company's proposed use of the 10.00 percent ROE in the ROR calculation for the 2018 TCR revenue requirement. The report from Concentric is included as Attachment 15 to this Petition.

The independent consultant applied three commonly-used analytical tools to assess the reasonableness of the Company's proposed 10.00 percent ROE: (1) the Constant

Growth Discounted Cash Flow (DCF) model, (2) the Capital Asset Pricing Model (CAPM), and (3) a Risk Premium model. Utilizing a weighted mix of three separate analysis methods to calculate ROE is a proper way to mitigate potential anomalous market conditions that may skew the results of any single ROE calculation method and result in incongruous ROE results.

A. DCF Model Irregularities

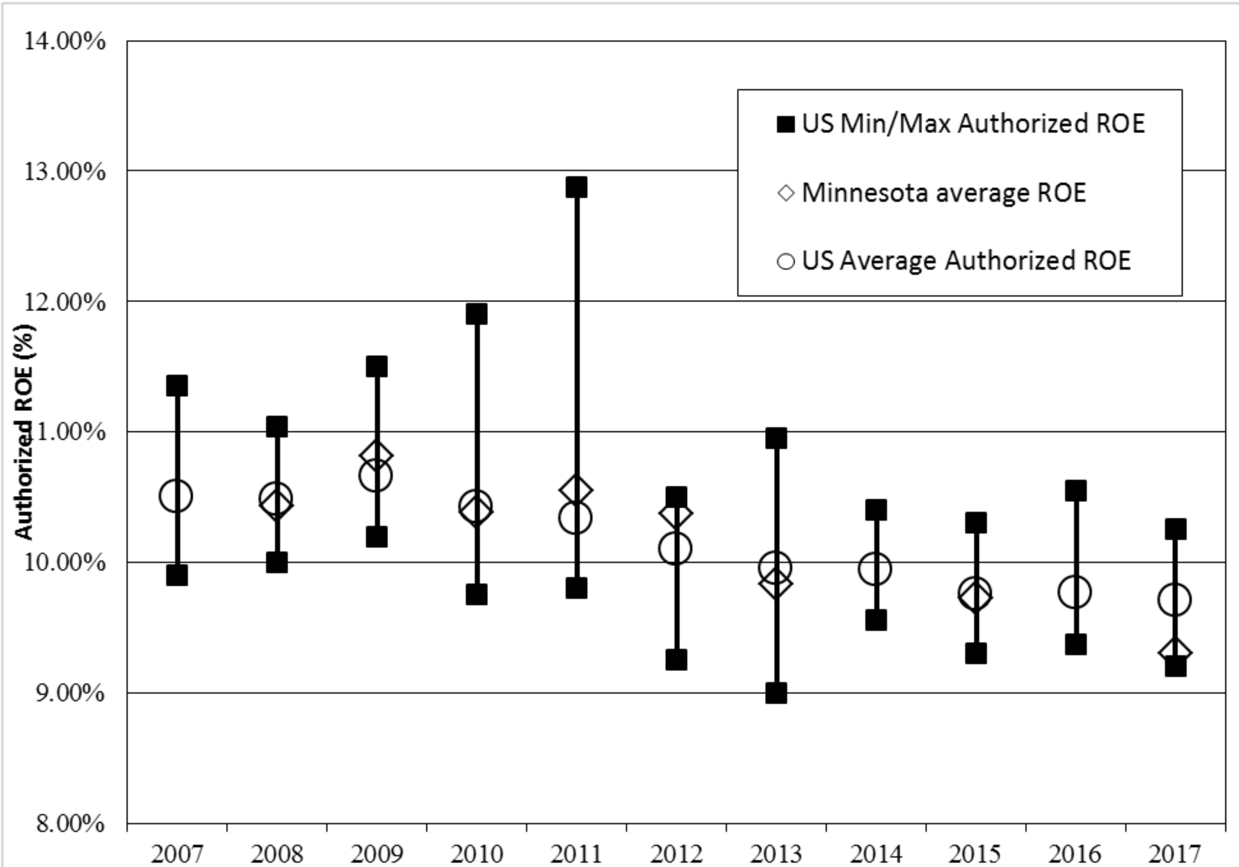
This concern is currently evident in the DCF model. Current dividend yields for utility companies are well below historical levels. That, in turn, results in a DCF model that produces depressed ROE results. By utilizing three different methods, we are able to use models that focus on historical market data (DCF model) as well as models that focus on forecasted market conditions(Risk Premium model and CAPM). This mitigates the risk of short term market conditions having an overweighted impact on future results, especially in a period where interest rates are expected to increase.

B. Competition for Capital

NSPM competes for capital on two fronts, both within Xcel Energy and outside the company in the investment market. If the Company is placed at the low end of authorized ROEs, both within Xcel Energy and the market as a whole, investments in Minnesota become a less attractive option. In the long term, this would hamper the Company's ability to access capital for necessary construction within Minnesota.

For frame of reference, Figure 10, shown in Attachment 15 and included below for reference, shows a comparison of the average authorized ROEs in the state of Minnesota in comparison to those in other markets. As can be seen here, Minnesota average authorized ROEs tend to be lower than the average in the United States utility market, are far below the maximum authorized ROEs, and have steadily declined since 2009.

Figure 10 (from Attachment 15)
Comparison of Minnesota and U.S. Authorized ROEs



C. Procedural Matters

The Company believes it would be helpful for the Commission to issue a procedural schedule that allows for an evaluation of the Company's proposed ROR and supporting analysis, as well as an evaluation of any analysis provided by parties which support their recommendations in an efficient manner. The Company recommends that all intervening parties provide their analysis of the Company's recommended ROE and ROR in their initial comments, which the Company will respond to in their reply comments. All parties can then update their ROE analysis in reply comments, if needed. After that, the Commission should only allow for additional ROE and ROR analysis to enter the record, up to the point where the Commission takes up consideration of the filing, if changing market conditions necessitate additional analysis.

VIII. REVENUE REQUIREMENTS AND TCR ADJUSTMENT FACTORS

In this section, we provide the 2017 and 2018 revenue requirements and the resulting TCR Adjustment Factors for the TCR Rider projects and charges identified in this Petition. For illustrative purposes, we have assumed an effective date of January 1, 2018 for purposes of calculating the Adjustment Factors over the forecast calendar year, though this assumption does not account for the 60-day statutory notice requirement. We propose to recalculate the final TCR Adjustment Factors to recover the 2017-2018 revenue requirements over remaining months of 2018, or some other period as approved by the Commission, upon approval of our Petition. We will provide the updated Adjustment Factor calculations as part of a compliance filing after the Commission issues an Order.

The combined 2017 and 2018 revenue requirements we propose to recover from Minnesota electric customers are approximately $109.5 million, an increase over the $80.2 million in 2016 revenue requirements approved in setting the current TCR Adjustment Factors.[7] Attachments 6 and 7 provide the supporting revenue requirements based on actual information through July 2017 and projected August 2017 through December 2018 TCR Tracker activity. Attachment 9 provides our projected 2018 TCR Rider revenues, calculated by customer class based on forecasted 2018 State of Minnesota billing month sales and the proposed 2018 TCR Adjustment Factors.[8]

A. Proposed TCR Adjustment Factors

The costs recovered through the TCR Rider are allocated to the NSP Companies (Northern States Power Company Minnesota and Northern States Power Company Wisconsin), to the Company's State Jurisdictions (Minnesota, North Dakota and South Dakota), and to the Minnesota Jurisdiction Classes (Residential, C&I Non Demand, and C&I Demand) based on the demand allocation factors approved in the Company's recently concluded electric rate case (Docket No. E002/GR-15-826). This approach is consistent with the Department's recommendation in our last TCR

[7] See January 17, 2017 Order and January 27, 2017 Compliance Filing in Docket E002/M-15-891. The current TCR adjustment factors were calculated to collect the 2016 revenue requirements, updated with actual revenues and expenses, over a 12-month period beginning February 1, 2017.

[8] The rate design for these factors was approved in the Commission's November 20, 2006 Order in Docket No. E002/M-06-1103 and the October 21, 2011 Order in Docket No. E002/M-10-1064. The rate design was amended in Docket No. E002/GR-12-961 where the Commission ordered that system coincident summer peak allocators should be used to allocate transmission costs, and again in Docket No. E002/GR-13-826 when the Streetlighting Class was removed.

proceeding to calculate the Adjustment Factors using the state jurisdictional allocators approved in the Company's last electric rate case.[9]

Within each of the non-demand metered classes of service, these allocated costs are recovered through a per kWh charge. We determine the per kWh charge for each class by applying a class-specific allocation factor to the Minnesota jurisdiction average per kWh TCR cost. The demand allocator is based on the sales forecast as approved in our last electric rate case in Docket No. E002/GR-15-826. The resulting annually-revised TCR Adjustment Factors recover the current costs.

For the demand metered class, the TCR adjustment factors are determined similarly; however, the factor to be billed is instead determined by using forecast year demands instead of sales to yield a per kW factor.

Table 1 below shows our proposed 2018 TCR Adjustment Factors and overall revenue requirements compared to the TCR Adjustment Factors which were implemented on February 1, 2017.

Table 1: Adjustment Factor Comparison

	2016 Approved	**2017-2018 Proposed**
Total Revenue Requirements	$80,525,828	$109,549,879
Residential Rate/kWh	$0.003503	$0.004645
Commercial Non-Demand/kWh	$0.003384	$0.004102
Demand /kW	$1.017	$1.274

An average residential customer using 675 kWh of electricity per month would see an increase on their bill of approximately $0.77 per month compared to the current TCR residential Adjustment Factor.

The proposed TCR Adjustment Factors are calculated assuming they are effective January 1, 2018. If the timing of a decision in this proceeding does not allow for a January implementation date, the Company requests that Adjustment Factors be recalculated to recover the 2017-2018 revenue requirements over the remaining months of 2018 in order to match 2018 cost recovery with the eligible 2018 costs, similar to the treatment authorized in past TCR Rider orders.

[9] See the Department's September 7, 2016 Response Comments in Docket No. E002/M-15-891 and the Commission's January 17, 2017 Order approving this approach. See also Ordering Point No. 1 of the Commission's August 14, 2014 Order in Docket No. E002/M-13-1179.

Because of the potential for a misalignment of the time a rate is effective compared to the revenue requirements intended for recovery, we request implementation of a two-way carrying charge starting January 1, 2019.

B. TCR State of Minnesota Revenue Requirements

The detailed 2017 and 2018 Minnesota jurisdictional revenue requirements by project in support of the proposed TCR Adjustment Factors are included in Attachment 13. Transmission Statute project revenue requirements, including Grid Modernization-Distribution projects, are calculated using the guidance provided in Minn. Stat. § 216B.16, subd. 7b(b)(2) and the Commission's prior related orders.

1. Transmission Statute Revenue Requirements

The Transmission Statute requires certain information be provided in support of our request. For ease, Table 2 below lists where the statutory filing requirements are located throughout this filing:

Table 2: Filing Requirements

Requirement	Authority	Location in Filing
a description of and context for the facilities included for recovery	Minn. Stat. § 216B.16, Subdivision 7b[c] 1	Attachments 1 and 1A contain the project descriptions for projects the Company believes are eligible for recovery under the TCR Rider.
a schedule for implementation of applicable projects	Minn. Stat. § 216B.16, Subdivision 7b[c] 2	Attachment 2 contains an implementation schedule for each of the projects identified in Attachments 1 and 1A.
the utility's costs for these projects	Minn. Stat. § 216B.16, Subdivision 7b[c] 3	Attachments 3A and 3B show the capital expenditure forecast for each identified project. Capital expenditures are accumulated from project inception through December 31, 2022.
a description of the utility's efforts to ensure the lowest costs to ratepayers for the project	Minn. Stat. § 216B.16, Subdivision 7b[c] 4	The Company has made extensive efforts to ensure the lowest cost to ratepayers for the proposed TCR-eligible projects. These efforts are discussed in the Project Descriptions in Attachments 1 and 1A.

Requirement	Authority	Location in Filing
calculation to establish that the rate adjustment is consistent with the terms of the tariff established in paragraph [b]	Minn. Stat. § 216B.16, Subdivision 7b[c] 5	Attachment 9 contains the calculation of the proposed TCR Adjustment Factors by customer class. We provide the details of these calculations under the Cost Recovery section of this Petition.

2. *MISO Revenue Requirements*

In addition to allowing the Company to recover the costs of transmission projects being constructed by the NSP System, the Transmission Statute allows TCR Rider recovery of charges billed under a federal tariff (such as the MISO Tariff) associated with other transmission expansions being constructed in the MISO region by other utilities. The actual charges through August 2017 and projected charges from September 2017 through December 2018 from the regional transmission projects included in the 2006 through 2017 MTEP cost allocations are presented in Attachment 12.

Expenses based on Schedule 26 and 26A of the MISO Tariff for 2017-2018 are forecast to be $141.5 million.[10] The Company expects these charges to be offset by $142 million in Schedule 26 and 26A revenues from MISO tariffs associated with regional rate recovery of NSP System project investments.

The forecasts result in net estimated Schedule 26 and 26A revenues to NSP that is less than expenses (positive revenue requirements) of $501,319 (total NSP System). The net revenues were further adjusted by an allocation to NSPW and other Company jurisdictions to arrive at the Minnesota jurisdiction of net RECB revenue of $368,171. This is shown in Attachments 4 and 12 as a positive revenue requirement where the RECB Revenue Requirements allocation is listed as $368,171 million. The Company believes the Schedule 26 and Schedule 26A cost recovery through the TCR Rider has been calculated consistent with the Transmission Statute, and it includes the MVP Auction Revenue Rights (MVP ARR) as we indicated in our June 19, 2015 Reply Comments in Docket No. E999/AA-14-579.

3. *Impact on TCR Rider of Pending FERC Complaint*

Multiple actions are pending at FERC related to the return on equity (ROE) that MISO transmission owners charge for regionally shared facilities. We provide a description of those proceedings below. For the purposes of calculating TCR revenue

[10] Pending complaints filed with FERC described further in Section VII. B. 3.

requirements, we apply the ROE currently ordered; however, future true-ups may be necessary depending on the outcome of the pending proceedings.

In November 2013, a group of industrial customers in the MISO region filed a complaint asking FERC to reduce the 12.38 percent return on equity (ROE) used in the transmission formula rates of jurisdictional MISO transmission owners, including NSPM. The FERC issued an Order approving a 10.32 percent ROE in September 2016, applicable for a refund period from November 12, 2013 to February 11, 2015 and prospectively from the date of the order. The total prospective ROE is 10.82 percent, which includes a 50 basis point adder for RTO membership. The amounts for under this complaint period were settled and reflected in the amounts in January and May of 2017.

In February 2015, an intervenor in the original ROE complaint filed a second complaint proposing to reduce the MISO region ROE, resulting in a second period of potential refund from February 12, 2015 to May 11, 2016. In June 2016, the Administrative Law Judge recommended an ROE of 9.70 percent, the midpoint of the upper half of the discounted cash flow (DCF) range, which applied the June 2014 ROE methodology. A FERC decision is expected in 2018.

On April 14, 2017 the D.C. Circuit Court of Appeals vacated and remanded Opinion 531, previously made in a New England ROE case. The court decision found that the FERC had not established that the prior ROE was unjust and unreasonable, and that the FERC also failed to adequately support the newly approved ROE. Since Opinion 531 was also cited as the basis for the MISO decision, the impact of this court decision on the pending and settled MISO complaint cases is uncertain.

FERC allowed MISO until July 2017 to complete refunds for the first complaint period (November 12, 2013 to February 11, 2015). MISO completed the refunds in two phases: (1) resettlement of the refund period by adjusting the original billing rates for the ROE change, and (2) resettlement of formula rate true-ups impacted by the ROE change. MISO settled the first phase in January 2017 and the second phase in May 2017. These refund adjustments amounting to $7.9 million at a Total Company level, are included in the 2017 Schedule 26 and 26A amounts in the tracker.

In calculating the 2017 and 2018 TCR revenue requirements, we apply the currently-authorized 10.82 percent MISO ROE for 2017 and 2018 activity. The tracker also adjusts the 2016 Schedule 26 and 26A amounts in the tracker to account for the 10.82 percent MISO ROE approved in September 2016. In addition the amounts for the period of November 12, 2013 to February 11, 2015, were resettled with MISO in January and May of 2017 and therefore the amounts in this filing include those amounts. However, future adjustments to the TCR Tracker may be necessary pending the outcome of the vacated Order 531 and the second complaint period. We will keep the Commission informed of any additional outcomes in these MISO ROE proceedings at the FERC.

4. *Other Costs Included in Revenue Requirement Calculations*

In addition to inclusion of the provisions in our Transmission Statute and Renewable Statute project revenue requirements models, the Company also includes costs approved by the Commission in previous TCR Rider Orders. For example, we use a projection of construction expenditures and costs for the 2018 forecast period. Allowable costs other than those previously mentioned include property taxes, current and deferred taxes and book depreciation. Attachment 7 summarizes the 2018 projected revenue requirements for these projects, and Attachment 8 summarizes the projected revenue requirements for 2019. Attachment 13 shows the revenue requirement calculations by project. Base assumptions are included in Attachment 10.

a. Interchange Agreement Allocator

For the purpose of determining the State of Minnesota jurisdictional revenue requirements for production and transmission plant investment, the Company uses a demand allocator, which reflects the sharing of costs between the Company and NSPW pursuant to the Interchange Agreement. Consistent with the allocation method approved by the Commission in our 2013 TCR Rider, we have used actual Interchange Agreement allocators for 2017 and budget allocators for 2018.[11] Any resulting over- or under-recovery from customers as a result of the use of the budget demand factors will be reflected in our next TCR Rider Petition that will use actual allocators as they are available.

b. Open Access Transmission Tariff (OATT) Calculation

We established the TCR transmission revenue requirement by also reflecting the revenue offset provided by wholesale transmission services under the MISO Tariff. The OATT revenue credit captures a portion of the revenue the Company receives from third party transmission customers who are charged the FERC-jurisdictional MISO tariff rate for use of the Company's transmission system. Our approach to this issue is consistent with the approach approved in the 2008 TCR petition, Docket No.

[11] Docket No. E002/M-13-1179, ORDER APPROVING 2014 TCR RATES AS MODIFIED, APPROVING 2013 TRACKER ACCOUNT, AND REQUIRING COMPLIANCE FILING, August 14, 2014. The 2017 Interchange Agreement allocation was accepted by FERC via its letter order dated May 26, 2017 in Docket No. ER17-1377.

E002/M-07-1156. This is separate from the revenue credit for MISO Schedule 26 and 26A RECB revenues.

The forecast period used to calculate the transmission formula rate under the MISO TEMT is consistent with the forecast period used to develop costs recovered under our TCR Adjustment Factors. In addition, the basis for both the MISO revenues and Transmission revenue requirements is a 13-month average plant balance.

Additionally, pursuant to Commission Order, we include CWIP in the OATT revenue credit calculation only for those projects that have not been designated by FERC as regionally shared projects or are not included in the MISO tariff (transmission serving generation or distribution). The CapX2020 La Crosse-Local project is included in the MISO tariff but has not been designated by FERC as a regionally shared project. Therefore, an OATT revenue credit has been applied to this project. Further, we exclude any projects designated as RECB projects, since all RECB costs and Company revenues are included in the TCR Rider. To apply the OATT revenue credit to RECB projects would be reducing project revenue requirements for revenue received from others twice, once through RECB revenues and once through the OATT revenue credit. The OATT revenue credit is shown in Attachment 11.

5. *Accumulated Deferred Income Taxes (ADIT)*

Since the time our last TCR proceeding went before the Commission in January 2017, several utilities have requested Private Letter Rulings from the Internal Revenue Service (IRS) to clarify the appropriate method of proration of the ADIT, including Otter Tail Power. During this time, we have been working with the Department to explore the issue, document the fact pattern for NSP-Minnesota, and evaluate whether a common approach to the issue is possible among the Minnesota-based utilities.

For the purposes of this filing, while these discussions are ongoing, the Company presents actual ADIT for the actual months of 2017.[12] The Company calculated the forecasted portions of 2017 and 2018 revenue requirements in accordance with our understanding of the proration formula in IRS regulation section 1.167(1)-1(h)(6).[13] However, we will continue to work with the Department and other stakeholders towards a reasonable resolution and will update these calculations, as needed.

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[12] Actual ADIT for the 2016 historic year was included in our January 23, 2017 compliance filing in our last TCR proceeding.

[13] A technical description of this issue can be found in Docket No. E002/GR-15-826, Exhibit___(LHP-1), pages 53-56, the Direct Testimony of Ms. Lisa H. Perkett.

6. Rate of Return

With the exception of a new ROE proposed above, the other components of the returns approved in our most recent state of Minnesota electric rate case are shown on Attachment 10 and have been used to determine the return on CWIP and rate base.[14]

7. Preventing Double Recovery

Attachment 1A includes additional discussion about the ADMS project costs as a portion of those costs were included in base rates in our recently completed electric rate case. The ADMS costs included in base rates have been removed from our TCR Rider revenue requirements as shown on Attachments 4 and 4A.

IX. TCR VARIANCE ANALYSIS REPORT

Order Point 4 of the Commission's Order dated April 27, 2010 in Docket No. E002/M-09-1048 states:

> *In setting guidelines for evaluating project costs going forward, the TCR project costs recovered through the rider should be limited to the amounts of the initial estimates at the time the projects are approved as eligible projects, with the opportunity for the Company to seek recovery of excluded costs on a prospective basis in a subsequent rate case. A request to allow cost recovery for project costs above the amount of the initial estimate may be brought forward for Commission review only if unforeseen and extraordinary circumstances arise on the project.*

In accordance with the above Order language, below we provide a brief discussion of factors contributing to cost changes of several of the projects since our last TCR filing. We note that no cost forecasts have increased since our 2015 TCR Petition. In addition, the projected in-service dates for all projects are the same as filed in our 2015 TCR petition. Only one transmission project included in the rider, La Crosse – Madison, is not yet in-service.

A. Big Stone – Brookings Costs

At the time we filed our 2015 TCR initial Petition in Docket No. E002/M-15-891, total project expenditure for the Big Stone – Brookings project was estimated to be less than the estimated total project costs as submitted to the South Dakota Public

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[14] Docket No. E002/GR-15-826

Utilities Commission in the initial filing.[15] Attachment 3B of the 2017 TCR Petition shows a further reduction in estimated project expenditures by an additional 9 percent (or 18 percent with internal labor removed, as shown on Attachment 3A). As discussed in our June 3, 2016 Reply Comments in the 2015 TCR, several factors contribute to the reductions. These reasons continue to explain the further cost estimate reduction. Specifically, the lower cost is reflective of 1) value engineering, whereby we were able to substitute materials and methods with less expensive alternatives without sacrificing quality or functionality; 2) estimate refinement where our actual appropriation cost was less than as originally scoped for the cost estimates; and 3) lower material prices. For example, steel commodity prices were at a 5-year historic low when the structures for this project were purchased, which helped reduce the total project cost. Because there is a true-up mechanism in the TCR Rider, customers will experience these project cost reductions through lower rates.

B. La Crosse – Madison Costs

Our June 3, 2016 Reply Comments also discussed a reduction in the estimated La Crosse – Madison expenditures. As noted in the Reply, the project ownership agreements were finalized on October 30, 2015, after the 2015 TCR Petition was filed, which reduced the Company's ownership share. Our project forecast was reduced from $192.2 million in the 2015 TCR initial Petition to $179.1 million to correspond with the final ownership percentage. The current forecast is 4 percent less than estimated at the time we submitted the June 3 Reply.

C. CapX2020 La Crosse Costs

The final segment of the CapX2020 La Crosse project was placed in-service in September 2016. The total investment for the CapX2020 La Crosse project through 2018 is estimated to be $310.0 million, which is less than the estimated $326.7 million presented in our 2015 TCR filing.[16] The current estimated cost at completion is within the escalated cost cap of $330.3 discussed in our past two TCR proceedings.[17] See our June 3, 2016 Reply for a discussion of the various factors impacting this

[15] SDPUC Docket Nos. EL06-002 and EL12-063, as discussed in the Company's June 3, 2016 Reply Comments in MPUC Docket No. E002/M-15-891.
[16] This estimate includes pre-eligible AFUDC and internal labor which is later removed for revenue requirement calculations. We believe the total project investment *including* these costs better reflects the total project costs and is a better dollar value to compare to the Initial Cost Estimate included in the CON docket. Attachment 3A shows project expenditure without internal labor costs and Attachment 3B shows project expenditure including internal labor costs for comparison.
[17] Docket Nos. E002/M-14-852 and E002/M-15-891.

project's costs in the years after the initial cost estimate was presented in Docket No. E002/CN-06-1115.[18]

X. REMOVAL OF INTERNAL LABOR COSTS

Consistent with the Commission's decision in Docket No. E002/M-12-50, we have excluded internal labor costs from the Transmission Statute and Distribution-Grid Modernization projects included in this filing. Table 3 below shows the cumulative amount of internal labor costs that have been removed through 2018.

Table 3: Internal Labor Expenditures Removed

Project	2018
CapX2020 Brookings – Twin Cities	$21,202,954
CapX2020 Fargo – Twin Cities	$17,045,225
CapX2020 La Crosse (MN, MISO, and Local)	$20,898,076
CapX2020 Big Stone – Brookings	$9,906,015
La Crosse – Madison	$8,292,241
ADMS	$1,092,951

XI. 2016 TCR COMPLIANCE FILING, TRUE-UP REPORT AND TRACKER BALANCE

Our January 23, 2017 compliance filing in Docket No. E002/M-15-891 provided the actual 2016 expenditures and revenues as required by Commission Order. We have made additional updates to the 2016 tracker since we made that compliance filing, which impact the 2016 final tracker balance. First, we noted on page 7 of our June 3, 2016 Reply Comments in the 2015 TCR our intention to update the 2016 state jurisdictional allocators once the 2016 test year allocators were approved in the concurrent rate case. The rate case was approved after we made the compliance filing, and so the 2016 tracker in this TCR petition makes this update to the approved 2016 allocators. Page 10 of the Department's September 9, 2016 Response Comments noted our intention to make this update. Second, the 2016 RECB amounts have been updated for a December 2016 true-up.

[18] The initial cost estimate was $276.5 million in 2007 dollars.

The changes to the tracker are reflected in the carry-forward balance shown on Attachments 5 and 6. The 2018 TCR Adjustment Factors include the carry-forward tracker balance from the 2016 period and the 2017 forecasted carry-forward balance.

XII. PROPOSED TARIFF SHEET AND CUSTOMER NOTICE

A. Proposed Revised Tariff Sheet

Attachment 16 includes both redline and clean versions of our TCR Rider tariff sheet updated to show the proposed TCR Adjustment Factors by customer class. The tariff provides that the TCR Adjustment Factors are included in the Resource Adjustment and that factors will be applied to customer bills subsequent to Commission approval. We propose an effective date of January 2, 2018; however, the tariff sheet and revised TCR factors will not be made effective until after the Commission acts on this Petition.

We also propose several administrative updates to the tariff. First, we propose to add references to distribution-related costs that are now eligible for inclusion in the TCR Rider. Second, we propose to remove references to the Street Lighting class. The Commission approved the removal of the Street Lighting class from the TCR rider in its June 29, 2015 Order in Docket No. E002/M-14-852.[19] At that time, we removed only the reference where the Street Lighting rate had been listed, but neglected to remove other references to the Street Lighting class elsewhere on the tariff page. Third, we remove a duplicative reference to the Minnesota Public Utilities Commission.

Attachment 16 shows the proposed administrative updates as well as the proposed new Adjustment factors in both clean and redline formats.

B. Proposed Customer Notice

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

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[19] The rate design was amended in Docket No. E002/GR-12-961 where the Commission ordered that system coincident summer peak allocators should be used to allocate transmission costs. Since street lighting customers do not contribute to our system coincident peak demand, street lighting should not be allocated any transmission costs. As such, Street Lighting was removed as a separate billing class when the TCR Adjustment Factors were calculated in Docket No. E002/M-14-852, and the rate was removed from the tariff at that time.

This month's Resource Adjustment includes an increase in the Transmission Cost Recovery Adjustment (TCR) which recovers the costs of transmission and distribution investments, including delivery of renewable energy sources to customers. The TCR portion of the Resource Adjustment is $0.004645 per kWh for Residential Customers; $0.004102 per kWh for Commercial (Non-Demand) customers; and $1.274 per kW for Demand billed customers.

We will work with the Department of Commerce and the Commission Staff if there are any suggestions to modify this proposed customer notice.

CONCLUSION

The Company respectfully requests the Commission approve this Petition. Specifically, we request the Commission:

- Approve TCR cost recovery of the ADMS Distribution-Grid Modernization project;
- Approve the 2017-2018 revenue requirements of $109.5 million for the projects eligible for cost recovery through the TCR Rider;
- Approve the proposed electric rider ROE used to calculate the revenue requirements;
- Approve the resulting TCR Adjustment Factors by class to be included in the Resource Adjustment on bills for Minnesota electric customers for the 12 months beginning January 2, 2018;
- Approve our 2016 TCR True-Up and Tracker Balance report and carry-forward of the 2016 Tracker balance; and
- Approve our proposed revised TCR tariff sheet and proposed customer notice.

Dated: November 8, 2017

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie Sieben	Commissioner
John Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE TRANSMISSION COST RECOVERY RIDER REVENUE REQUIREMENTS FOR 2017 AND 2018, AND A REVISED ADJUSTMENT FACTORS

DOCKET NO. E002/M-17-____

PETITION AND COMPLIANCE FILING

SUMMARY OF FILING

Please take notice that on November 8, 2017 Northern States Power Company, doing business as Xcel Energy, submitted to the Minnesota Public Utilities Commission a Petition for approval of the 2017 and 2018 Transmission Cost Recovery (TCR) Rider revenue requirements of $109.5 million and revised TCR Adjustment Factors to be included in the Resource Adjustment on customer bills for electric customers in Minnesota. We propose to recover costs related to one new distribution-grid modernization project that has previously been certified by the Commission.

TCR Rate Rider Petition Attachments
Table of Contents

Transmission Cost Recovery Rider
Descriptions of Eligible Projects

Attachment 1 describes the projects proposed to be included in the 2017-2018 TCR Rider request.

Transmission and Renewable Projects Previously Approved as Eligible:

In its Order dated April 27, 2010 in Docket No. E002/M-09-1048, the Commission approved TCR Rider cost recovery for the following eligible projects under Minn. Stat. 216B.16, Subd. 7B:

- CapX2020 Fargo – Twin Cities
- CapX2020 La Crosse

In its Order dated February 7, 2014 in Docket No. E002/M-12-50, the Commission approved TCR Rider cost recovery for the following eligible project under Minn. Stat. 216B.16, Subd. 7B:

- CapX2020 Brookings – Twins Cities

In its Order dated January 17, 2017 in Docket No. E002/M-15-891, the Commission approved TCR Rider cost recovery for the following eligible projects under Minn. Stat. 216B.16, Subd. 7B:

- La Crosse – Madison (also referred to as Badger – Coulee)
- Big Stone – Brookings 345 kV Line

Eligibility of New Transmission Projects:

We are not seeking the determination of eligibility of any new transmission projects at this time.

Eligibility of New Renewable Statute Projects:

We are not seeking the determination of eligibility of any new renewable projects at this time.

Eligibility of New Distribution-Grid Modernization Project:
The Company seeks eligibility determination for the following project under Minn. Stat. 216B.16, Subd. 7B:

1. Advanced Distribution Maintenance System (ADMS)

Project Description and Context &
Efforts to Ensure Lowest Cost to Ratepayers

As required by Minn. Stat. 216B.17, Subd. 7B (5), the ADMS project was certified by the Commission under Minn. Stat. 216B.2425 in its June 28, 2016 Order in Docket No. E002/M-15-962. Please see Attachment 1A for a full description of this project, its context, and our efforts to ensure the project brings the best value possible to our customers.

Efforts to Ensure Lowest Cost to Ratepayers

The transmission projects currently included in the TCR rider are joint projects between utilities and, with the exception of the La Crosse – Madison project, are part of the CapX2020 Initiative. Many of the CapX2020 planning benefits described below are benefits also experienced by coordinating with another utility for projects such as the La Crosse – Madison project. Working with other utilities helps to ensure cost-effective construction and a less piecemeal approach to transmission project planning.

In particular, the CapX2020 group of utilities established a coordinated regional approach to addressing both regional and community reliability needs, and longer-term growth. To ensure cost-effective implementation of the CapX2020 projects, the Company, through its participation in the CapX2020 Initiative, provided for a prudent means of developing the projects. The CapX2020 Initiative was formed to meet the growing transmission needs of all utilities in the region. By coordinating regional planning, the region's utilities are able to develop complete solutions to regional transmission needs instead of disjointed solutions that could lead to duplicative transmission facilities being built. Further, by acting as a group, the CapX2020 Utilities obtain improved efficiency in permitting, routing, scheduling, material purchasing and overall project development. Overall, the Company's participation in the initiative allows us to lessen our costs and achieve greater benefits from the projects due to the strength and size of the organization. For example, by working together, the CapX2020 Utilities have been able to develop a comprehensive set of alternatives for improvement of the transmission system, as opposed to crafting disjointed solutions that would result from individual utility solutions.

In addition, working together within the regulatory environment to jointly file applications for permits in all of the affected jurisdictions allows regulators to more fully understand the scope, benefits and impacts of the projects and not be subjected to numerous separate filings by individual utilities on separate projects that may, at times, work at cross purposes. The joint approach taken by the Company and the other participating CapX2020 utilities is a prudent way to proceed with developing the projects in order to spread the costs among a broad array of utilities. An investment of approximately $1.8 billion for all of the projects would be difficult for any one utility to undertake. By collaborating with a number of other regional utilities, the Company is able to successfully spread its risks and balance its costs.

Finally, the Company and the participating utilities recognize that there are benefits arising from a coordinated effort in securing materials and services required to build the CapX2020 projects. As such, a joint sourcing approach has been utilized to pursue benefits in order to minimize or eliminate inter-project competition for labor and material resources, maximize leverage on vendors and specification standardization, establish a common request for proposal (RFP) process to present one "CapX2020 face" to the market and eliminate inefficiencies, maximize inter-project flexibility where possible for services. For example, utilizing a joint sourcing process across the projects creates a spend volume asset. This volume consolidation and early RFP activity allows manufacturers and suppliers the ability to plan fabrication in advance of the delivery needs. This approach works to avoid the premium costs associated with orders outside of the lead time and typically garners more attractive pricing when the suppliers, manufactures and contractors are able to advance plan their production schedules or field resources.

ADMS PROJECT DETAILS

Xcel Energy is in the process of implementing a comprehensive Advanced Grid Intelligence and Security (AGIS) initiative to ensure the electric distribution grid is well-positioned to meet future grid and customer needs while maintaining reliability, safety and security. In our first Grid Modernization Biennial Report initially filed with the Commission on November 1, 2015 (Docket No. E002/M-15-962), we sought project certification of an Advanced Distribution Management System (ADMS). The Commission certified the project in its June 28, 2016 Order in that docket. In support of cost recovery of this project, below we discuss the need for ADMS, the process for selecting a vendor to provide the system, the customer benefits of the ADMS, and other information in support of the project.

In summary, ADMS is a critical software platform that will provide the foundational system necessary to provide integrated grid preparedness, improve reliability, and to increase efficiency on the grid. The industry is moving to ADMSs and we are confident this investment will serve our customers and the advanced grid for many years to come. The Company has gone through an extensive process to select an ADMS vendor that will be able to deliver the overall business requirements that have been determined as necessary to provide the capabilities required to operate a modern electric distribution grid. ADMS is not only a foundation tool; it is a critical part—the "engine"—of the overall package of tools necessary to deliver reliability, energy efficiency measures, and to enable the integration of increasing quantities of distributed energy resources without compromising reliability and power quality.

As noted in our 2015 certification request, we provided an initial cost estimate of $27 million for 2016, 2017, and 2018 (plus an additional amount of unquantified funding beyond those years) based on preliminary vendor cost estimates and industry partner experience. Due to the timing of the new legislation authorizing us to file for certification of grid modernization projects on June 13, 2015 and the required statutory filing date of November 1, 2015, we were unable to prepare and submit a thorough budget estimate at that time and committed to submit a more thorough request and documentation at the time of our request for actual cost recovery. Since that time, we have spent significant time and resources researching and developing our plans and as a result we now provide more detail to support our cost recovery request. The ADMS budget was developed using an extensive process in which information was collected from other utilities, industry experts, consultants, and a rigorous sourcing process. We now estimate the total Minnesota budget for ADMS to be $69.1 million (on a MN basis) across the span of 10 years- through 2025- (with $25 million of that investment being spent between 2016-2018, consistent with our

2015 initial estimate). We believe that the importance of the ADMS project and our extensive and thorough vendor selection and budgeting processes support cost recovery for this important project.

I. OVERALL NEED FOR ADMS

A. Background

ADMS is a software platform that provides the foundational system for operational hardware and software applications. It acts as a centralized decision support system that assists the control room, field operating personnel, and engineers with the monitoring, control and optimization of the electric distribution grid. ADMS does this by utilizing the as-operated network model[1] and maintaining advanced applications[2] which provide the Company with greater visibility of an increasingly complex electric distribution grid. In particular, ADMS incorporates Distribution Supervisory Control and Data Acquisition (D-SCADA) measurements and smart grid technology executions with the enhanced network model to provide load flow calculations everywhere on the grid that accurately adjusts with changes in grid topology. This allows the Company to improve the monitoring and control of load flow from substations to the edge of the grid which enables multiple performance objectives to be realized over the entire grid.

B. ADMS Functionality

As we previewed in our 2015 Grid Modernization Biennial Report, the core ADMS software will offer the following main functions:

- *Distribution Network Modeling:* All distribution substations, primary feeders, and devices will be connected in ADMS to provide a network model that represents the entire distribution grid from the high side of substation transformers down to the secondary side of service transformers, including Distributed Energy Resources (DER).

[1] The network model is the model that represents the entire electric distribution grid and consists of the connectivity and representation of all distribution substations, primary feeders and devices.
[2] ADMS advanced applications are modern grid technologies that allows the Company to achieve various grid performance objectives. Refer to Section IV. A. for the Company's ADMS Application graphic which identifies examples of advanced applications.

- *Distribution SCADA:* D-SCADA enables the monitoring and controlling of remote field devices. These devices include, but are not limited to, substation devices, intelligent field devices, Distribution Automation (DA) devices, DER and future, emerging devices that will integrate with the electric distribution grid.

- *Load Flow, State Estimation and Network Topology Processor:* The network topology processor adjusts the network model to reflect changes in the electric distribution grid due to switching activity or other grid disturbances. State Estimation uses measured values from DA devices to improve load flow calculations. This will enables the Load Flow application to provide real-time load flow calculations for all segments of the grid and allows smart grid technologies to have continued accuracy as the grid changes.

The above five functionalities are foundational to the ADMS platform and all advanced applications of ADMS and future integrated technologies will be facilitated through them.

C. Need for ADMS

ADMS is a key foundational element for Grid Modernization. Once it is implemented, new grid capabilities and functionalities will be enabled that will help the Company fulfill the vision of a fully integrated advanced electric distribution grid. The key objectives of ADMS are to provide integrated grid preparedness, improve reliability, and to increase efficiency on the grid. Examples of how ADMS meets these objectives and more are discussed below.

- *Integrated Grid Preparedness:* With an increasing penetration of Distributed Energy Resources (DER) forecasted, along with existing electric distribution grid impacts, it is essential to have a system that enables integration of grid technologies and functionalities. The existing electric distribution model and analysis tools available to the operators were not built to accommodate the increasing penetration of DER. ADMS allows the system to adapt by managing the complex interaction of DER, outage events, feeder switching operations and smart grid technologies in one system. This proactive approach to DER management will provide our customers with safe, reliable, and economic power.

  ADMS enables the Company to transition from a passive to an active DER management approach because of the DER Management capabilities within

ADMS. DER Management runs in real-time and allows operators to monitor DER with an awareness of its effect on the entire electric distribution grid. For example, operational risks associated with DER are reduced because the DER Management capabilities can display reverse power flow and the hidden load[3] at every protective device along the feeder. By knowing what DER is active in the grid and its impact, the Company can continue to incorporate DER on the grid and still ensure safe operations.

ADMS applications are needed to provide operational assistance in the study and management of DER on the electric distribution grid. ADMS provides visibility and situational awareness of DER on the distribution grid through utilization of the real-time network model and load flow calculations. Along with this network model, several advanced analysis tools are available that will aid in increasing efficiency and accuracy of DER management and interconnection processes.

- *Reliability:* ADMS supports operators in determining optimal solutions faster during outage restoration through utilization of the network model, load flow calculations, and advanced analysis tools. ADMS, in conjunction with automated grid components, can improve reliability and quality of service in terms of reducing outages, minimizing outage time, and enabling advanced energy efficiency. For example, operators can perform a restoration analysis that quickly provides them with options for outage restoration. Another example is a fault location tool, FLISR, which calculates the possible locations of the outage cause.

  As discussed in our November 1, 2017 Grid Modernization Report filed in Docket No. E002/M-17-776, FLISR is an advanced application of ADMS that, in concert with field devices and proper communication, improves grid reliability and operational performance during outages.[4] FLISR provides remote monitoring control of the field devices and involves deploying automated switching devices with the objective of decreasing the duration and number of customers affected by an individual outage. ADMS-based FLISR is beneficial because it acts as the common distribution integrated control platform for multiple corporate objectives operating in the same area. This optimizes and ensures safety during FLISR operations because there is an awareness of the impact FLISR device operations have on the grid as a whole that a standalone FLISR system would not have.

[3] Load that is masked by DER and can cause trouble when performing switching operations.
[4] *Fault Location, Isolation, and Service Restoration Technologies Reduce Outage Impact and Duration.* US DOE. December 2014. https://www.smartgrid.gov/files/B5_draft_report-12-18-2014.pdf

Additionally, ADMS provides a central management scheme with the agility for dynamic reaction to distribution grid changes so FLISR devices can automatically restore customers outside the fault zone.

- *Operational Efficiency:* ADMS acts as an integrated distribution control platform that provides improved grid efficiency by enabling efficient execution of technologies on the same area of the grid through central control of automated devices. By having a system with central control, Xcel Energy can combine grid topology awareness with field automation to optimize outage response effectiveness and power quality performance on the grid. For example, distribution operators will manage multiple technologies in one ADMS system which reduces the amount of time operators spend switching between different programs, gives the ability to optimize workspaces, and increases overall efficiency in operations.[5] Another example is the improvement in operational training that ADMS provides. These training tools are necessary to efficiently transfer knowledge about operations of the electric distribution grid to new employees.

  ADMS' integration capabilities enable ADMS to extend the value of the smart grid technology to new and emerging grid performance objectives. For instance, ADMS uses Advanced Metering Infrastructure (AMI) meters as sensors, in near real-time, to improve power flow accuracy and advanced application performance within ADMS. Full realization of smart grid technology benefits is only leveraged in an integrated system. Currently, technologies implemented at Xcel Energy are stand-alone, so full realization of smart grid technology benefits cannot be leveraged.

  ADMS enables the optimization of each smart grid technology by using a single as-operated network model with accurate load flow calculations. By acting as an integrated distribution control platform, multiple corporate objectives can be achieved in a safe and efficient manner.

- *Safety:* By using an integrated ADMS platform, the Company can ensure safe operations between different technologies operating in the same area. In addition, ADMS provides a single network model which can reduce the workforce miscommunication safety risks associated with having multiple models of the distribution system. Other safety benefits are enabled by ADMS analysis tools.

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[5] Taylor, Tim and Kazemzadeh, Hormoz *Integrated SCADA/DMS/OMS: Increasing Distribution Operations Efficiency* http://assets.fiercemarkets.net/public/smartgridnews/dms_abb_02.pdf

For example, load flow analysis calculates and displays bidirectional load flow which gives distribution operators both visibility and situational awareness for safe operations of the distribution grid with DER present.

- *Cybersecurity*: As Xcel Energy moves forward into the next generation of intelligent electric distribution, each and every facet of the electric network must be scrutinized and evaluated for cybersecurity risk. ADMS has incorporated zone methodologies to layer cybersecurity controls. This includes segmentation of control system communications by function and implementing advanced grid specific security processes and standards to protect, detect, respond and recover from cybersecurity risks of this foundational system. Reliable delivery of electricity is of paramount importance, protecting the integrity and security of this system is included with that responsibility.

- *Asset Optimization:* ADMS utilizes an enhanced network model with real-time load flow calculations. This provides accurate information and representation of the distribution grid, which is necessary for strategic operational planning of existing and future assets.

- *Customer Benefits:* A more intelligent distribution grid will be able to better meet customers' energy needs, while also integrating new sources of energy and delivering power over a network that is increasingly interoperable, efficient and resilient. ADMS will increase visibility and situational awareness on the increasingly complex electric distribution grid so Xcel Energy employees can operate the grid safely, efficiently, and reliably without compromising the needs of any of our customers.

D. Alternatives to ADMS

The industry is moving to ADMS to provide the capabilities necessary for a more integrated grid and Xcel Energy needs to stay at the forefront of what is expected to become the industry standard in the near future. Over the last number of years the Company has looked for alternatives to ADMS, but there are no comparable alternatives. Even so, some of the benefits facilitated by ADMS may be found through targeted improvements beyond the chosen option of purchasing and installing an ADMS across the Xcel Energy grid.

For instance, increasing the size of the cables would increase capacity on the electric distribution grid. Although this improvement could allow for an increased amount of

DER, it would only serve that one objective. In contrast, an ADMS allows for an increased amount of DER in addition to enabling DER Management. Increasing capacity on the grid, in comparison to ADMS, does not best support the Commission's vision to effectively modernize the grid because it fails to provide a real-time awareness of load flow which assists the Company in the management of DER.

Another way for the Company to achieve some of the benefits facilitated by ADMS is to install separate, autonomous systems that would integrate with existing SCADA and OMS systems instead of installing a fully integrated ADMS. This alternative does not provide the platform for smart grid technologies that is necessary to enable a fully integrated grid. Devices would operate on their own at individual sites in the field without awareness of each other. The Company has pursued implementing some autonomous systems (i.e. SmartVAR pilot,); however, these systems are isolated and aren't able work together. If the Company wants multiple corporate objectives on the same distribution grid, ADMS is the necessary integrated distribution control platform that enables safe and efficient operation of multiple corporate objectives in the same area.

A final alternative would be for Xcel Energy to do nothing in way of grid enhancement, maintaining the status quo of current grid capabilities. This option limits the ability to integrate higher levels of DER and other advanced technologies and limits the ability to improve grid efficiency and reliability. It would not meet our customers' needs to allow our grid to remain stagnant when there are new technologies that can improve reliability and expand customer options.

ADMS is currently the only comprehensive platform that can accomplish what is necessary to implement the Company's overall Grid Modernization initiative. It provides both situational awareness and automated capabilities that sustain and improve the performance of an increasingly complex grid. ADMS enables integration of DER and other technologies in addition to improving grid efficiency and reliability. ADMS, acting as the comprehensive integrated platform for grid technologies, provides the integrated system that is imperative for a modernized grid to operate efficiently and safely.

II. SELECTION PROCESS FOR CHOOSING AN ADMS PLATFORM

A. Background

To ensure that the ADMS platform is successfully installed and positioned for ongoing functionality on our grid, it was crucial to select a highly qualified vendor who would assist the Company in achieving the core functionalities and benefits discussed above. A detailed list of more than 3,000 system requirements was defined and included in an RFP that was sent to potential ADMS vendors. In addition to requirements that addressed the goals of the foundational ADMS platform, requirements defining future goals of the system were included in the RFP so that the functionality of the selected ADMS is scalable and can grow. The selected vendor will provide a system that meets the requirements specified and also will act as a long-term partner in support of our Company mission to "provide our customers the safe, clean, reliable energy services they want and value at a competitive price."

We desired a vendor that had experience in developing, implementing, and supporting electric distribution real-time SCADA and ADMS control systems. Our ideal vendor would also have a successful track record in the implementation of ADMS applications, specifically Distribution Load Flow, State Estimation, DER Integration, and Fault Locate Isolation and Service Restoration (FLISR). Lastly, it was important for our vendor to have pre-existing, excellent customer support for the ADMS control systems they have already implemented on large electric distribution grids.

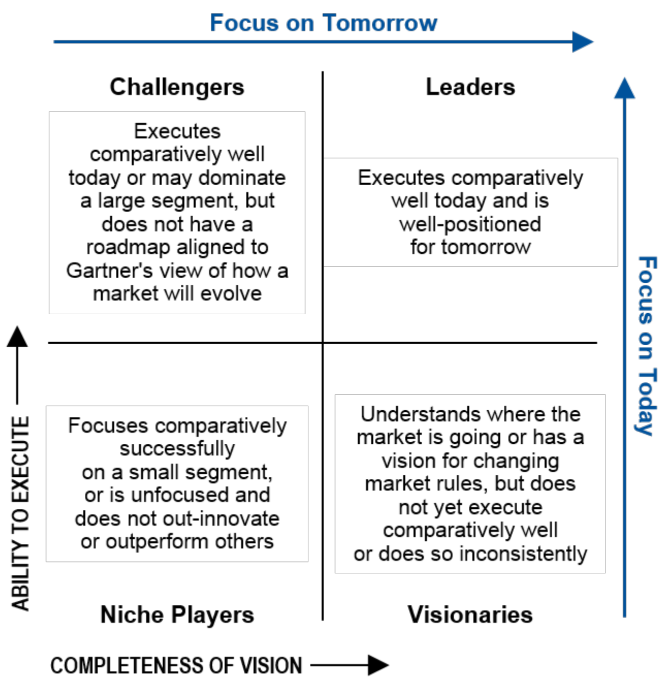
We used the following five-stage process which we discuss in more detail below.

Chart 1:
Five-Stage Project Development Process

B. Market Analysis

When the Company began the process of selecting and installing an ADMS, one of the first steps was to research the ADMS market, including potential vendors. The Company utilized Gartner Research[6] to get an unbiased, research-based view of the existing ADMS market. A very useful resource from Gartner was the Magic Quadrant for the ADMS Market.[7] This report helped the Company understand the existing ADMS market by visually providing four quadrants and identifying where each competitive vendor in the market was positioned. Chart 2 shows the four generic quadrants: Challengers, Niche Players, Leaders and Visionaries. Chart 2 identifies that a vendor who has the strongest ability to execute and the most complete vision would fall in the Leaders quadrant. The Company used up-to-date Gartner Magic Quadrants throughout the RFP Process in order to identify the current leading vendors in the ADMS market.

Chart 2:
Gartner Magic Quadrant for the ADMS Market



[6] Gartner Research is an IT research company that provides tools to help companies make decisions about technology. They provide a reliable, actionable, unbiased, and informative insight on current industry trends.
[7] *How Markets and Vendors Are Evaluated in Gartner Magic Quadrants.* Gartner Research. January 2016. https://www.gartner.com/doc/3188318?ref=SiteSearch&sthkw=magic&fnl=search&srcId=1-3478922254

The next step in the Market Analysis stage of the RFP process was to gather information from other utilities' experience with ADMS implementation and ongoing functionality to inform our own process. To that end, key Company personnel visited several other companies' Distribution Control Centers in 2013 as we began developing our own system requirements. These site visits allowed us to observe two different ADMS systems in action. During these site visits we analyzed use, implementation, costs, surprises, and lessons learned.

We learned a great deal from studying these utilities' implementation processes and from conversations with the personnel directly involved in the selection and implementation of ADMS at those utilities. We paid particular attention to their lessons learned as we developed our own requirements assessment. For example, two utilities emphasized the importance of having accurate GIS data and how transitioning the workforce mentality concerning GIS data accuracy is now essential to the operation of the electric distribution grid. Because of this lesson learned, in our requirements assessment the Company addressed incorporating and verifying GIS data in the Program Development System (PDS) Environment, which is the environment that supports the initial testing stages of ADMS.

We also looked specifically at why each utility had chosen its ADMS vendor. These utilities chose their vendor for reasons such as: the vendor had the most functionality, the vendor was the only that could do certain advanced applications at the time, and the vendor had the most highly qualified technical resources creating their ADMS product, including the number of staff with advanced degrees. Understanding other utilities' reasons for selecting their vendors helped the Company create an RFP that would highlight the vendor's ability to accomplish specific goals.

As part of the Market Analysis stage in the RFP process, we also considered whether it was a better option for Xcel Energy to build our own customized ADMS platform instead of purchasing an "Out-of-the-Box"[8] product. However, the Company would better be able to control costs by choosing a system that has already been developed with the functionality we need. The Company determined that the vendor selected should provide an "Out-of-the-Box" product which is beneficial for many reasons, including: ease in installation, ease in upgrading software, simpler integration of other systems, and better support. For example, when installing an "Out-of-the-Box" product, the testing is more predictable because of the minimal amount of

[8] An "Out-of-the-Box: product means the vendor's product should meet the Company's needs with their existing solution and minimal customizations.

customization, there is a lower cost in installation because the vendor doesn't have to customize their code, and the process of implementation can run more efficiently because both the Company and vendor would be working with software that has already been through the implementation process.

C. Develop Business Requirements

Near the beginning of our ADMS project, the Company hired The Structure Group, now a part of Accenture, to assist in the RFP creation and vendor selection process. The Structure Group is an industry expert specializing in large smart grid implementations and proved to be a very useful resource in the ADMS planning phase. They supported Xcel Energy throughout the entire vendor selection process. In particular, The Structure Group assisted a cross-functional ADMS Core Team from Xcel Energy in developing and finalizing a list of detailed requirements.

D. Request for Proposal (RFP) & Vendor Evaluation

The RFP process is a standard Xcel Energy business practice when selecting a software product. Additionally, when looking at other utilities' experiences, we found that almost all companies with an ADMS product used an RFP process for vendor selection. This observation confirmed that an RFP process was the best course of action for Xcel Energy in order to fully evaluate the vendor options and their products. The primary objectives of the RFP was to create a contract foundation, get easily comparable vendor information in order to select the vendor of best fit, and to obtain fixed pricing. This process ultimately assisted the Company in selecting a vendor's software product that was optimal in regards to cost and functionality.

The RFP consisted of several components, all of which were detailed. This ensured that each of the vendor's proposals would align with Xcel Energy's mission and timeline, and also prevented surprise costs when it came time to sign the contract. The RFP began by introducing the existing Xcel Energy distribution grid and then went into detail about each of the specific components of our ideal ADMS Platform.

Once the RFP was developed, we targeted its dissemination to vendors identified as best aligning with our needs and goals. Research that provided an independent insight in our decision making, along with looking to other leading utilities, helped Xcel Energy identify the eight leading vendors in the ADMS market. We used resources such as Gartner Research, lessons learned from other utilities, industry benchmarking, and attending the DistribuTECH[9] conference to assist us in creating the initial ADMS vendor pool. The RFP was sent to these vendors in March 2014 with specific instructions for their proposal format and important deadlines to meet if they wanted to be considered. An addendum was sent out in August 2014 to include technical requirements and specifications for an ADMS-SCADA system.

Xcel Energy's ADMS Core Team developed and agreed upon a scoring methodology for the eight vendor proposals. The proposals submitted underwent an evaluation process which included vendor self-assessment of requirements, scoring done by Xcel Energy individual employees and teams, and an evaluation of the software cost. Based on the scoring, a shortlist of three vendors was selected and they then had opportunity to present their proposals through demonstrating their solutions and recommended customer site visits.

The demonstrations were done in-house, lasting three and a half days each. Three months prior to the demonstrations, the vendors received select electric distribution model data and a detailed demonstration agenda from Xcel Energy. Using Xcel Energy-specific data was key to the demonstrations because it proved if the vendor's product would work with Company data. These shortlisted vendors were then evaluated and scored.

D. Recommend Final Vendor

Based on the final scoring, Schneider Electric proved to be the vendor that could best meet Xcel Energy's requirements and be our long-term partner. We chose a vendor that we believed was compatible with Xcel Energy and the Company's long-term goals, and the company that is seen as the industry leader. Schneider Electric was founded in 1836, with ADMS available since 1995. The company's headquarters is in Paris, France but they have a strong presence around the world with more than 150,000 employees in more than 100 countries. Around 20 percent of the employees are located in more than 225 offices around the U.S., several of which are leaders in Schneider Electric's Smart Grid IT.

Schneider Electric provides a system that meets the specified requirements and has the ability to act as a long-term partner and support mechanism for years to come.

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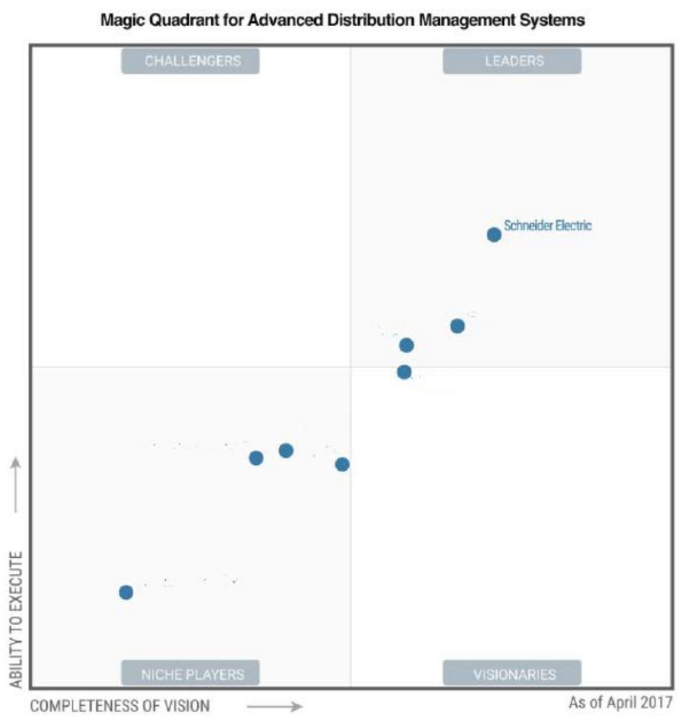
[9] The DistribuTECH conference and exhibition event is collaboration amongst leading companies in the electric power transmission and distribution industry. This event is essential for companies in the power industry to learn about new technologies and to network with colleagues.

Amongst the eight vendors who submitted an RFP, Schneider Electric scored the highest in our evaluated scoring criteria. In other words, Schneider Electric met the most of our established requirements and had the most comprehensive and mature software.

Schneider Electric's ADMS has been rated by Gartner Research as the market leader since 2014. This rating was based on the ADMS completeness of vision, number of functional components in production, and ability to execute. Chart 3 below shows Schneider Electric to be the current market leader in 2017. Their position has increased in both vision and execution since 2014, which contrasts to the other leading vendor who have advanced only slightly between 2014 and 2017.[10]

Chart 3:



In choosing a vendor, we desired past experience in developing, implementing, and supporting electric distribution real-time SCADA and ADMS control systems, a successful track record in the implementation of ADMS applications, and a pre-existing, excellent customer support for the ADMS control systems they have already implemented on large electric distribution grids. We are confident that Schneider

[10] The March 2014 Magic Quadrant for Advanced Distribution Management Systems has not been published publically. The April 2017 Magic Quadrant was made public in April 2017 on LinkedIn.

Electric meets these criteria and is the vendor that provides the highest level of benefit under our various requirements.

III. INSTALLATION OF THE ADMS PLATFORM

A. Initial System Roll-out

The Company began detailed design for implementation of ADMS in 2016. We first examined our service territories across all of the Xcel Energy jurisdictions to assess how to best roll out ADMS. We determined that the Public Service Company of Colorado (PSCo) would be ideal for the initial ADMS roll-out, owing to its varied nature, increasing penetration of DER, and Commission implementation requirements.

Implementation of the ADMS platform will consist of detailed design, installation, testing and verification of the network impedance model and of the functionality of the core applications of ADMS. As part of this process we will also verify connectivity to the SCADA field devices. Other existing devices that lack advanced communication or control capabilities will be unable to remotely interact with ADMS.

ADMS software development, configuration and integration building began in 2017 across all operating companies. Testing and deployment of the ADMS software will begin in the PSCo jurisdictions in 2019 followed by implementation in the NSP jurisdictions and the other operating companies.[11] The initial schedule for deployment in NSP was estimated to occur in 2019 after the PSCo implementation. Subsequent to completing the detail design phase in 2017, the schedule for deployment in the NSP jurisdictions is now planned to occur in 2020. This schedule change was made based on Schneider Electric's implementation methodology and schedule which includes rigorous testing and training activities to be performed for each operating company's implementation.

The expected in-service date of the NSPM ADMS software is the first quarter of 2020. The software in-service date is based on the partial network impedance model, which consists of around 80 feeders, making up 7 percent of all NSPM feeders. This network model includes a representative sample of feeders and substations that enable us to test the software and its capabilities against a minimal set of feeders by providing

[11] The NSP Companies include Northern States Power Company Minnesota (NSPM) and Northern States Power Company Wisconsin (NSPW).

a diverse set of operating and grid conditions. The partial network impedance model consists of a select set of substations and feeders that were chosen based on the following set of criteria:

1. The selected substations and feeders were a good representative sample of the distribution grid of NSP.
2. The selected feeders were identified as having the most benefit of running the FLISR application.
3. The remaining selected feeders have automated devices that are already installed which provide the necessary visibility needed to manage the grid.

When the Company has determined that ADMS is properly functioning on the partial network impedance model, the software will be placed in-service. The core and advanced functionality of ADMS will then be deployed to the other feeders. The full network impedance model, which is required to enable full use of advanced applications, is expected in late 2025. In addition to the full network impedance model, intelligent devices must be installed and operational to realize the full benefits of ADMS advanced applications.

B. Geospatial Information System (GIS) Data Collection Effort

As mentioned in our 2015 certification request, the Geospatial Information System (GIS) is a critical system that will need to be integrated with ADMS. Accordingly, concurrent to the roll-out of the hardware and software components of the ADMS system, we will carry out a critical GIS data collection effort. As mentioned above, GIS data is critical to the ADMS to provide location and specification information for all of the physical assets that make up the distribution system. ADMS will use that information to maintain the as-operated electrical model and advanced applications. While the Company has good asset records, we have not tracked all to the level of detail that ADMS will require in order to operate effectively. Therefore, the Company needs to review all of its physical asset records to ensure that the information available complies with the necessary level of detail needed for ADMS.

The GIS data collection effort is comprised of three components. The first is collecting data that will validate the physical characteristics of the current system. Since the ADMS is dependent on a robust dataset, we will leverage system and data knowledge and confirm the accuracy and completeness of the electric distribution grid model. This is accomplished by verifying the information contained in the corporate GIS via the performance of a physical data verification and capture effort with the goal of determining the level of readiness to support the ADMS application. We will also ensure the representations of customer load profiles and distributed generation are accurate to meet the needs of advanced applications.

The second is collecting the additional data that defines the electrical characteristics necessary to enable the ADMS model. We will collect any missing data such as the size of wiring, the size and location of equipment such as transformers, switches, poles, phasing and connectivity, and device control settings. This process validates the various data attributes contained in the corporate GIS system. As a result, the physical plant versus the electrically connected model are reflective of one another. The data collection effort exceeds the capacity of the current workforce to complete. To accomplish this effort over the next several years, the Company hired a data collection vendor. An RFP process and a performance comparison methodology was used to select the most accurate and cost effective vendor.

The third is implementation of select intelligent field devices in order to test ADMS and ensure it has the necessary operating information. In order to ensure that ADMS is operating efficiently and effectively the Company must complete end to end testing of the system and that cannot be done without field devices to gather the information that is needed for ADMS to operate and demonstrate it functions appropriately. As a result, some intelligent field devices will be implemented early for purposes of this testing. These devices are permanent and will be used as part of the intelligent field device deployment. ADMS processes the information provided by these devices in near real-time and then uses the information in its application algorithms. ADMS then sends control commands from the advanced applications to the intelligent field devices to effect the necessary change in power flow on the grid.

The Company has entered in to a Technology Partnering Agreement with the National Renewable Energy Laboratory (NREL) and our ADMS vendor, Schneider Electric, to perform a study that will assist in determining the optimal mix of field device sensor data and asset data quality necessary to cost-effectively realize desired ADMS benefits. This study will use four substations and six feeders with real data from Xcel Energy. A member of the Department of Energy sponsored ADMS "Testbed," a consortium of national laboratories; NREL has the ability to assist the Company in this effort because it maintains a demonstration laboratory that will allow the Company to model how ADMS will interact with various levels of data.

C. Training Plan

We have developed and will implement a formal training plan for Xcel Energy employees and contractors who will operate and maintaining the ADMS. Our contract with Schneider includes formal training on the software and included applications. Schneider's formal training process uses an approach based on previous training experience with more than 80 utilities. We will use a "train the trainer" approach. This model has been proven an excellent method to transfer knowledge to Company employees and ensure the Company can maintain an effective training program. Online training modules will be built as well to ensure both refreshment and new user training.

The Operator Training Simulator is an advanced application of ADMS that will be used regularly for operators and operating engineers. The operator training simulator has the following capabilities:

- Mimic the real-time distribution grid
- Training scenarios that operators can interact with
- Replay of past events
- Restoration drill scenarios support
- Regional drill support

We believe this initial training lays the right groundwork for the launch of the ADMS platform on our system, and the ongoing training ensures sustainable and long-lasting usability at Xcel Energy.

D. Ongoing Maintenance Plan

As discussed above, we were interested in choosing a long-term partner when we selected Schneider Electric as our vendor for the ADMS platform. Part of this long-term partnership is ongoing support and maintenance from Schneider Electric. The rates, support, and maintenance commitment were all topics of negotiation in the contract development process. Terms for both the warranty and maintenance service agreements are in place.

IV. PROJECT BUDGET

To ensure success and prudent spend related to the AGIS initiative, the Company has taken and will continue to take the following steps: engage in benchmarking with peer utilities in the industry; leverage industry leading technology experts; utilize key business partners in robust sourcing processes; establish formal internal governance structure that includes senior business leadership executives; establish rigid decision processes and financial governance including rigorous project change request and approval processes; and select an initiative level business management consultant to further support the overall governance and management of the projects.

Xcel Energy employs standard processes and procedures for selecting technologies to be deployed in the Company's environment as well as the execution of large capital projects. These processes are designed to ensure that the Company is both containing costs appropriately and spending money on the items necessary to achieve the desired outcomes and overall reasonable costs. These standard processes have been, and will continue to be, utilized within the ADMS project and the wider AGIS initiative we are pursuing. These standard processes include:

- **Product Selection** through an RFP process, as described in detail above, which is intended to ensure the most optimal solution for the Company's needs was selected and the price was negotiated to optimal costs to the Company.
- **Project and Initiative Governance Processes** which follow the Company's ULC (Universal Life Cycle) processes for all aspects of the project. This includes managing scope, risks, issues, milestones and financials. All changes to scope that have an impact on project costs, schedules, risk and benefits are reviewed through clearly defined levels of governance including project steering committees, AGIS Leadership, Integration Council (Cross-function Senior Leaders) and executive sponsors. This process, called PCR (Project Change Request), follows formal documentation and approval processes and limits at each level and are reviewed and documented in bi-weekly Change Board meetings with AGIS Leadership.
- **Contingency** that will be refined as the project progresses and more details are identified, which is prudent to present an anticipated cost level that is achievable. The use of the contingency is closely managed and subject to internal approvals.

A. Budget Development

Our preliminary ADMS project cost estimate, as previewed in our 2015 Grid Modernization Biennial Report, was $9 million per year for three years (2016, 2017 and 2018), for a total of $27 million. As noted at that time, this was a high level estimate based on preliminary vendor cost estimates and industry partner experience due to the timing of the grid modernization amendment being passed in June and the submission of our certification request in November.

After the conclusion of the RFP and vendor selection processes, a more detailed project estimate was created from the pricing and contract verbiage as well as internal labor and hardware to support the overall ADMS project.

Upon completion of detail design work, a detailed implementation plan was developed and the project estimates were updated. The final ADMS project budget for Minnesota is $69.1 million.[12] The cost estimate includes five key components: Labor, Software, Hardware, GIS Data Collection Efforts, and contingency. Because the ADMS is being developed as one software system across the Xcel Energy enterprise system and will be implemented in each specific operating company on a different timeline, the ADMS costs will be allocated to specific utilities and jurisdictions. The allocation process is discussed further below.

Table 1: Project Capital Budget Summary (Dollars in Millions, on a MN basis)[13]

	Pre-2016	2016	2017	2018	2019	2020+	Total
Labor	2.1	2.7	6.3	6.8	10.1	1.4	29.4
Software	0.0	0.0	1.9	1.3	0.0	0.0	3.2
GIS	0.0	0.0	0.1	0.4	1.5	28.9	31.0
Sub-total	2.1	2.7	8.3	8.5	11.6	30.3	63.5
Hardware	0.0	0.0	3.1	2.3	0.2	0.0	5.6
TOTAL	2.1	2.7	11.4	10.8	11.8	30.3	69.1

i. Labor

The ADMS labor estimate was developed from a bottoms-up forecast of all resources required to complete the Implementation phase. The bottoms-up labor estimate includes labor costs already incurred (2016 and 2017) through the detail design phase along with estimates to complete the work for the build, test and implementation phases. Labor components for the implementation phase include external vendors (Schneider, General Electric and Oracle), Xcel Energy employees, and contractors. Vendor cost estimates are based on contractual agreements with each vendor. Employee and contractors include resources from Distribution, IT and program

[12] The total budget for Xcel Energy is $208.9 million.
[13] Please see Attachment 3B for the NSPM Total Company CWIP Expenditures for the ADMS project costs being requested in this TCR Petition.

management. The employee and contractor labor forecast was based on a roll-up of all resources required to perform the project work and the estimate durations for each.

Consistent with the Commission's decision in our 2012 TCR proceeding, we have excluded internal labor costs from the ADMS project costs requested in the TCR.

ii. Software

The software portion of the ADMS budget consists of license agreement and various third-party infrastructure. The Schneider license agreement is a fixed cost and has been fully executed. The third-party software consists of licenses for the operating systems, databases and security products to operate and secure the ADMS system. The cost estimates were based on the number of hardware environments, servers, and processors based on existing license agreement costs with the third-party companies.

iii. Hardware

Detail system processing requirements were gathered through the RFP process as well as the contract process with the selected vendor for the ADMS system. These detailed requirements were used by the project team and the Company's infrastructure team, in conjunction with the ADMS vendor's technical experts, to determine size, scale and costs for all aspects of the infrastructure needed to adequately, securely and reliably operate the ADMS system for the Company. The types of hardware required include processors, data storage, security hardware/software, network devices such as firewalls and core switches, as well as critical data center infrastructure including power, cooling and cabling.

Hardware costs have been excluded from the project revenue requirements requested in the TCR as discussed further below in the Cost Allocations section.

iv. GIS

In order to create a GIS project budget the Company engaged in the following scoping activities:

- A gap analysis was conducted to determine the information currently available in the Company's GIS data model and what additional information is needed for ADMS to run successfully.
- Identification of changes required to the GIS data model to support ADMS.

- Identification of data that is to be captured from other sources (such as substation equipment databases) and how this will be provided to ADMS.
- Assessment of the quality of data currently held in the GIS and external sources and determine if additional data cleanup activities are required.
- Identification of data attributes that are to be field verified and updated in the GIS.

Two vendors participated in a Colorado data collection pilot effort in 2017. Their RFP responses provided expected costs for data collection by pole and substation. We used those per unit costs and extrapolated them using greater Public Service system information.

B. Allocation

As described in the Company's most recent electric rate case, O&M costs for preliminary planning related to capital software projects that benefit more than one operating company are allocated consistent with the Cost Assignment and Allocation Manual (CAAM) and the Service Agreement between Xcel Energy Services Inc. (XES) and NSPM.[14] As described above, the ADMS project will be implemented across all operating companies of Xcel Energy.

When a new shared asset software system is in construction work in progress (CWIP), the accumulating charges will be collected under one work order for Xcel Energy Services. Since the Service Company will not own software, the appropriate percentage of ownership for each participating legal company would be identified at the time of the initial development of the project. Each company's share of the cost would be charged to that company's CWIP monthly while under development and ultimately classified to their own books. Each owner will depreciate their respective share of the asset and as such no allocation is usually necessary. Care is taken to identify all beneficiaries at the beginning of the project so as not to allow later users a free service. In the case of ADMS, all operating companies and jurisdictions will benefit.

Investment in hardware for ADMS is being made in both PSCo and NSPM to support the system in all operating companies. There are primary and back-up servers located in data centers in both Minnesota and Colorado that will serve the NSP,

[14] See the Direct Testimony of Company Witness Mr. Adam R. Dietenberger in Docket No. E002/GR-15-826, pages 9-10.

PSCo, and SPS systems. Due to the flexible use of the various hardware components to support all the instances of ADMS, the Company determined that these investments would be purchased as network equipment and therefore charged out to all operating companies through our standard shared asset allocation process, similar to other data center network equipment. A carrying cost on this hardware investment is further allocated to the various operating companies. As a result of this allocation process, we do not believe it is practicable to recover the hardware costs of the ADMS through a rate rider. Therefore, we have shown the detailed hardware costs above for completeness in describing the project, but do not include these costs in the TCR revenue requirement. ADMS hardware costs will be included in a future rate case.

C. O&M and Service Life

The Company's approved depreciation in Minnesota for communication equipment software and hardware is 9 years. However, in Docket No. E,G002/D-17-581, the Company proposed a 10 year life for communication equipment. The Department of Commerce, in their initial comments, has recommended approval of the depreciation rates the Company proposed. The docket is awaiting Commission order. The ADMS project components will have either a 9 or a 10 year life depending on the outcome of the pending depreciation docket. Each Xcel Energy operating company will in-service the ADMS components separately as they are completed. As noted above, we anticipate in-servicing the NSPM ADMS software components in 2020.

At this time, we estimate that once placed in-service, the Minnesota ADMS system should cost about $1.9 million per year in O&M costs to pay for external software support and maintenance, hardware support, wide-area network costs and internal labor supporting the application and technical infrastructure. As discussed above, our contract with Schneider includes an ongoing agreement to provide support. We have also budgeted for both capital & O&M labor for the engineering and support expenses anticipated to maintain and operate the system.

Table 2:
Minnesota Project O&M Summary
(Dollars in Millions, MN Basis)

	2016	2017	2018	2019	2020+
Labor – Distribution and Internal Support	0.0	0.0	0.0	0.3	5.9
Training & Communications	0.0	0.0	0.1	0.1	0.6
I/T Hardware Support and Network	0.0	0.0	0.0	0.1	1.4
Software Maintenance Agreements	0.0	0.0	0.1	0.4	5.5
TOTAL	0.0	0.0	0.2	0.9	13.4

D. ADMS Costs in Base Rates

Company witnesses Mr. David Harkness and Ms. Kelly Bloch briefly discuss the ADMS project in their direct testimony in our recently concluded electric rate case.[15] Approximately $4.4 million in capital additions related to the information technology component of the ADMS project was included in the 2018 multi-year rate plan revenue requirement. This cost is only a limited portion of the full ADMS system. Attachment 4A shows the removal of this limited portion of the ADMS from the revenue requirements requested in the TCR Rider at this time.

CONCLUSION

The Company has gone through an extensive process to select an ADMS vendor that will be able to deliver the overall business requirements that have been determined as necessary to provide the capabilities required to operate a modern electric distribution grid. ADMS is not only a foundation tool; it is a critical part—the "engine"—of the overall package of tools necessary to deliver reliability energy efficiency measures and to enable the integration of increasing quantities of distributed energy resources without compromising reliability and power quality. The budget for ADMS components were developed using this extensive process in which information was collected from other utilities, industry experts, consultants and a rigorous sourcing

[15] Docket No. E002/GR-15-826

process. We believe that these careful vendor selection and budgeting processes support cost recovery for this important project.

Identification of Impedance Model Improvements Needed to Implement ADMS Applications in Xcel Energy Territory

National Renewable Energy Laboratory

Revision 14

June 30 2017

1. Purpose

Xcel Energy is making a major investment in deploying an Advanced Distribution Management System (ADMS) on their system and is planning to have the first deployment of the system by early 2019. Xcel Energy and the National Renewable Energy Laboratory (NREL) have held discussions on the effort needed to identify the depth of impedance model improvements needed by Xcel Energy to maximize the benefit of various ADMS advanced applications, such as Fault Location, Isolation and Service (Supply) Restoration (FLISR), Integrated Volt-VAR Optimization (IVVO) and Fault Location Prediction (FLP). It may prove to be prohibitively expensive for Xcel Energy to invest in a pilot deployment of an ADMS on their system for the sole benefit of understanding the data improvement needs. The parties also held discussions to evaluate the functionality of the Schneider Electric ADMS along with field measurements to identify the trade-offs between measurement density and impedance model improvement needs, and determine if more field measurements decrease the necessity for extensive field data collection. If so, what types of data and feeder locations may not need field data collection. As a result of these discussions, it has been determined that Xcel Energy would like assistance in assessing the value of impedance model improvements, versus measure density, by testing various network models and simulations with the VVO functionality on the ADMS system along with intelligent devices on the distribution feeders.

Work under this Modification will address the needs identified and reviewed by Xcel Energy at the Energy Systems Integration Facility (ESIF) at NREL. This effort will be complementary to the Department of Energy (DOE)-funded parallel project to establish an ADMS testbed at ESIF.

2. Methodology

NREL's ADMS Testbed

The ADMS Testbed at NREL's ESIF (Figure 1) is at the core of the abilities/competencies required for achieving the project objectives. The figure also shows the two phases of this project: Phase 1 will make use of a software-based distribution system simulation and a separate instance of ADMS (under test). Phase 2 will use the same methodology plus adding power hardware connected to the software simulation and/or directly connected to the ADMS under test.

As shown in the figure below, the testbed will deploy Schneider Electric's ADMS with IVVO and SCADA applications. The ADMS will contain the models of the selected feeders (4 metro & 2 rural) that will be provided by Xcel. The other blocks in the figure show the testbed components that will mimic a part of

Xcel's actual distribution system. The distribution power flow block will perform computations required to simulate the behavior of the distribution network through the power flow solver. The solver will be loaded with the real ADMS distribution feeder models consisting of detailed representation of power system assets such as cables, transformers and relevant secondary assets such as protection relays, voltage control devices, etc. There are two options available for the power flow solver:

Simulation Engines: An array of power system simulation engines is capable of mimicking distribution system behavior. The most common tool for distribution system simulation is OpenDSS , a Quasi-Static Time Series Simulation (QSTS) platform that allows simulation of power system phenomena in the time scale of a few seconds to seasonal and yearly patterns. Real-time simulation platforms such as RTDS and Opal-RT are highly sophisticated platforms capable of running real-time simulations. They are used for performing transient and phasor domain simulations – they capture power system phenomena spanning microseconds to a few seconds. These platforms are also most suitable for performing evaluations involving power hardware due to their real-time capabilities.

ADMS Power Flow Engine: An alternate approach to simulation engines will be to utilize the ADMS's intrinsic power flow engine. In this approach, an instance of the ADMS power flow Engine will be created outside of the ADMS and will be loaded with feeder models. There would be two instances of the ADMS power flow solver – an Internal Instance for the use of ADMS's internal applications like IVVO and FLISR and an External Instance to replicate distribution power flow outside the applications. These two power flows will carry independent sets of distribution models. While the External Instance carries the most-curated model dataset, the Internal Instance will be embedded with model data of different levels of impedance model improvement (Impedance Model Improvement Levels are discussed in the next section).

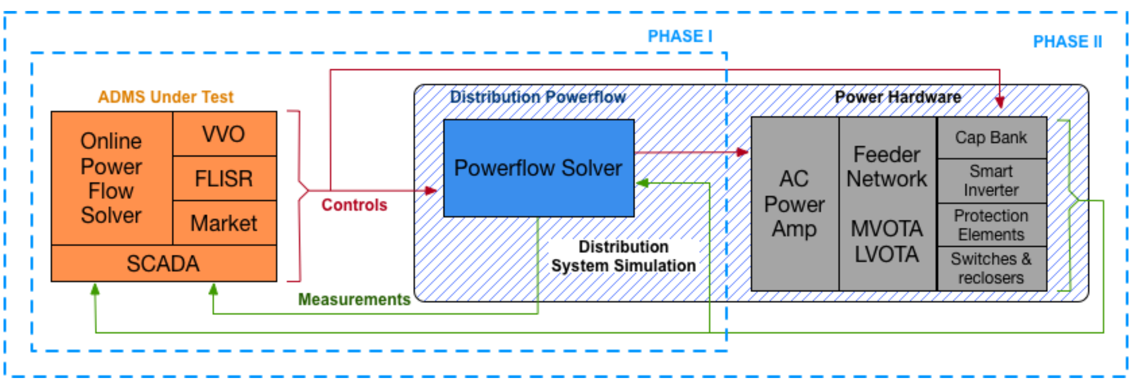


Figure 1: Illustration of ADMS Testbed at NREL

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https://sourceforge.net/p/electricdss/wiki/Home/
https://www.rtds.com/real-time-power-system-simulation/
http://www.opal-rt.com/power-systems-overview/

Phase I plans to use the second option for the power flow solver and Phase II plans to use the first option. The ADMS under test will interact with the "distribution power flow" through two paths – control and SCADA. Through the control path, the ADMS through its applications will send control set points to the different components inside the power flow block as if it were interacting with real power system assets. The SCADA path will allow the ADMS to receive inputs from the distribution power flow as if it were receiving measurements from real field devices. During Phase 2 of the project, the testbed will enable the ADMS to interact with power hardware directly or through the software simulation. The objective is to represent the distribution system as realistically as possible for testing the ADMS. Integration of power hardware in the testbed enables studying the interaction of the ADMS with actual hardware devices. The power hardware could consist of a multitude of field assets that are used for control and measurement or hardware like battery, PV and grid simulators and Distribution Generation (DG) assets. The selected hardware will be interfaced with the testbed through power amplifiers such that these hardware controllers interact with the testbed identical to their performance in the field.

Impedance Model Improvement Levels

Xcel Energy has identified four different impedance model improvement levels for which the performance of the ADMS applications will be evaluated. The data quality and availability improve progressively as we move from Level 1 to Level 4. The impedance model improvement levels are described below:

Level 1 – This is base level data extracted from the Xcel Energy GIS with some defaulting in order to perform minimum power flow.

Level 2 – This will include the scope of work in Level 1. In addition, field verification will occur at select locations to obtain wire size where unknown, obtain or confirm step transformer attributes, and collect capacitor, regulator and recloser attributes. These asset locations will be non-contiguous.

Level 3 – This will include the scope of work in Level 2, in addition to tap phase verifications.

Level 4 – This will include the scope of work in Level 3, in addition to field confirming each primary pole line by circuit to obtain distribution transformer attributes, phasing, and using Xcel Energy GIS data: (a) identifying new assets not shown in GIS or (b) identifying assets no longer existing in the field.

Measurement Data Levels

In addition to the impact of impedance model improvement levels, the performance of the applications will be evaluated with the inclusion of different sensor data. Xcel Energy will specify the levels of measurement density. This sensor data will be obtained from different field measurements and autonomous control devices like S&C switches, G&W/SEL reclosers, and Cooper capacitor controllers. In the simulation environment these will be obtained using simulated devices on the ADMS power flow host utility instance. To quantify the impact of sensor data, Xcel Energy has identified four different measurement levels on the representative feeder. The measurement levels are described below:

Level 1 – Feeder head measurements.

Level 2 – Measurements from Level 1, voltage regulators, capacitor banks, reclosers, and 1 tail-end voltage sensor (AMI sensor) per feeder with communications.

Level 3 – Measurements from Level 2 and a total of 10 AMI sensors per feeder

Level 4 – Measurements from Level 3 and a total of 20 AMI sensors per feeder.

AMI sensors will be placed on the secondary side. It is anticipated that evaluating the above possibilities can identify a trade-off of the impedance model improvement and grid measurements needed to successfully implement ADMS applications. As an outcome, NREL will provide an ADMS model/application matrix heat map (As show in Figure 2). This matrix will show the number of field measurement devices increasing on the horizontal axis, with the level of impedance model improvement increasing on the vertical axis. The performance of the application will then be determined at each coordinate point on the chart, which will correspond to the Z-axis of the chart. The performance will be evaluated based on the relative error of the application results as compared against the results at the highest level of both impedance model improvements and field measurement devices. The intent is to illustrate/validate that more field measurements decreases the necessity for field data collection. A heat map will be provided for the different IVVO performance metrics. The heat map below is for illustration purposes only and does not specify actual ADMS model/application performance.

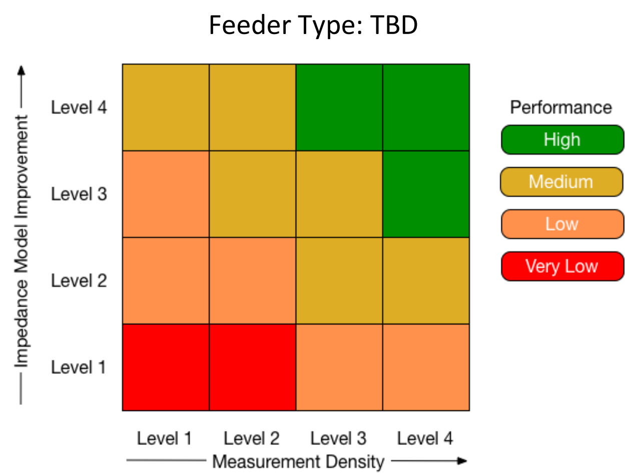

Figure 2: Heat map of data availability and measurement density

3. Approach

The project will test the impedance model improvement and grid intelligence needed for successful Integrated Volt/VAR optimization (IVVO) operations with ADMS. To achieve this, NREL will work with Schneider Electric to install their ADMS at NREL and train NREL staff to exercise the ADMS for the necessary use cases. NREL will also work with Schneider Electric to create a utility host environment replicative of six Xcel distribution feeders.

Phase I

Phase I will use software simulation components of NREL's ADMS Testbed as described in Section 2 Methodology: NREL's ADMS Testbed. NREL will work with Schneider Electric to run the ADMS power flow, IVVO and SCADA applications faster than real-time to be able to run simulations at a faster rate for analysis purposes. This will enable NREL researchers to run different ADMS applications that will analyze days' to weeks' worth of data over the course of several hours. Additionally, these applications will run across multiple use cases that vary in terms of the data that is fed to the ADMS system. Schneider Electric engineers will implement representative networks identified by Xcel Energy on Schneider Electric ADMS for simulation purposes.

Task 1: Install Schneider ADMS at NREL and Identify feeders

Subtask 1.1 – Identify Xcel Energy feeders for simulation: Xcel Energy will identify the utility feeders and impedance model improvement scenarios needed for evaluations. There will be four metro feeders and 2 rural feeders provided by Xcel Energy to NREL for analysis.

Subtask 1.2 – ADMS licensing and Training: In this task, NREL will establish a sub contract with Schneider Electric to obtain an ADMS license, install Schneider ADMS at NREL and train NREL staff to run the ADMS. ADMS testing will primarily use IVVO along with supporting applications such as Power Flow, State Estimation, SCADA, DG Monitoring, etc. Also as part of this subtask, NREL will enter into a three-party NDA between Schneider, Xcel Energy and NREL to exchange proprietary data needed to run the studies.

Subtask 1.3 – Import ADMS Feeder Models: Schneider Electric will prepare the design for importing different sets of data, implementing different levels of measurement density and simulating different load levels. SE will also import and build network model into the ADMS and perform data tuning.

Task 2: Implement Xcel Energy system models, establish a host utility environment and initialize ADMS application engines at NREL

Subtask 2.1 – Model Xcel Energy feeders in the ADMS: In this task, Xcel Energy will provide impedance model improvement levels 1 & 4 CIM files for each of the chosen feeders (4 metro and 2 rural). Xcel Energy will also provide feeder data representing impedance model improvement levels 2 and 3 in GML file format. Alternately, Schneider Electric may edit the feeder models in the ADMS to obtain levels 2 and 3, as necessary. Xcel Energy will provide load allocation factors for all the selected feeders. Xcel Energy will provide feeder-head and other measurements (as available) for the selected feeders. The measurements will cover four "representative" days – peak summer day, peak winter day, and two "shoulder" days.

Subtask 2.2 – Establish a host utility environment at NREL using multiple instances of Schneider Electric power flow application: In this task the team will use a second instance of the existing integrated power flow solver of the ADMS to establish a closed-loop Quasi-Static Time Series (QSTS) simulation replicating the utility network as a host system for evaluating ADMS applications. This setup will be capable of simulating the ADMS/distribution system combination either using historical data or allowing the ADMS to implement a set of advanced functions that can be tested in QSTS, which include local control modes and IVVO. The team will establish a model baseline for the IVVO application on the representative circuit at a faster than real-time scale. The team will work with Xcel Energy to implement Xcel Energy system load profile data in the ADMS for the baseline implementation.

Subtask 2.3 – Offsite and Onsite Testing of virtual machine (VM) and model improvement functionality: Schneider Electric will perform offsite testing of VM and model improvement functionality. SE will also deploy and test the VM onsite in NREL premises (lab) and local onsite testing. SE will establish the link between SE ADMS and SE simulator platform for performing the model improvement tests and enable NREL researchers to collect data from these tests. SE will train NREL staff to run the ADMS using different models and measurement densities.

Task 3 – ADMS GIS impedance model improvement level analysis

Subtask 3.1 – Illustrate incremental accuracy benefit for each proposed GIS static impedance model improvement level. Xcel Energy has four potential levels of possible GIS impedance model improvement as discussed in Section 2. NREL will quantify the difference in application performance between the impedance model improvement levels using the Schneider ADMS power system model for IVVO. Analysis will be done over the full feeder load range of -400 A to + 800 A by identifying different load profiles. The purpose of using minus 400 amps is to test for DER power flow from the distribution feeder into the substation.

Subtask 3.2 – Evaluate impedance model improvement using field measurements: NREL will evaluate and recommend defaulting and inference rules and values to improve model accuracy with reduced data collection efforts. In this task, NREL will re-evaluate all the impedance model improvement levels by including field measurements simulated on the host utility power flow instance.

Subtask 3.3 – Analyze the results: In this task, NREL will provide an ADMS model/application matrix heat map (shown in Figure 2) to show where additional field monitoring devices could potentially reduce the need for GIS data collection. A few iterations of possible field measurement locations will be identified in discussion with Xcel and the impact will be evaluated against different impedance model improvement levels to generate a tradeoff Matrix as shown in Figure 2. Heat maps will be provided for IVVO performance metrics.

Subtask 3.4 – Execution Support: SE will provide execution support for Task 3 including model updates, system tuning, test execution, and results interpretation.

Task 4: Project Management, Reporting & Results Dissemination

This task will ensure that all project deliverables are provided on time and within budget. NREL will provide Xcel with verbal updates on project status during the regularly scheduled weekly project meetings, including a summary of activities to date, and planned activities for the next period. NREL will also provide a project report at the end of the project as part of this task. The team will document all assumptions, including: defaulting of GIS attribute values, inferences of GIS attribute values, substation model attributes, dynamic topology (typically from DSCADA, TSCADA, OMS), Transmission system state (Source impedance, voltage, current, Voltage angle, etc.), dynamic device states (Load Tap changers, voltage regulators, capacitors), DER (Distributed Energy Resource) output, customer load profiles, customer generation profiles, feeder device SCADA values, etc., in the reports. NREL will summarize and publish the results from this work in an industry-available paper with the consent from Xcel Energy. Table 1 shows the roles and responsibilities of each participant as part of the phase I.

Table 1: Roles and Responsibilities of Each Participant

Xcel Energy	Identify 4 metro and 2 rural feeders and provide data for data evaluation of IVVO application. Provide impedance model improvement level 1 & 4 CIM files to be uploaded into ADMS. Provide impedance model improvement levels 2 & 3 models in GML format. Provide load and measurement data for the close feeders to run the baseline simulations. Assist NREL in identifying the sensor deployment scenarios for using measurement Data. Assist NREL in identifying the use cases that have different impedance model improvement levels as needed.
NREL	Create a utility host environment at ESIF using two different instances of Schneider ADMS power flow applications. Identify performance metrics, develop test plan and perform test design for measuring the performance metrics. Set up the test bed, perform multiple experiments and collect test data. Analyze the data and provide heat map for IVVO application performance for different levels of measurement density and impedance model improvement for the different performance metrics. Manage subcontract with Schneider Electric.
Schneider Electric	Facilitate design sessions to document and align on project specific use cases, data requirements, deployment environments, teat plans, etc. Import or manually create 4 impedance models into the ADMS database. Configure and tune environments and perform onsite readiness testing of VVO and other applications to support simulations of varying measure densities and load factors. Install ADMS at NREL and perform onsite validation tests. Train NREL staff to operate the ADMS, change impedance model and measure density levels, execute tests, and collect data. Support project execution, project management, and results dissemination

Phase II

During a subsequent Phase II of the project, the team will evaluate the device interoperability and implementation of the ADMS applications using NREL's ADMS Hardware testbed, described in Section 2.2. The project teams will develop the SOW for Phase II at a future time.

4. Deliverables

Table 2 shows the list of deliverables for the project.

Table 2: Schedule of Deliverables

Deliverables Phase 1:	Due
Application results quantification of four impedance model improvement levels.	7 months from delivery of test feeder information
Recommended defaulting and inference rules and values.	8 months from delivery of test feeder information
Application performance matrix heat map of new field monitoring devices vs. impedance model improvement levels. One for IVVO, one for FLISR (time and budget permitting), and one for combined overall ADMS model.	9 months from delivery of test feeder information

5. Schedule

The proposed schedule for the tasks and deliverables is given below in Table 3.

Table 3: Schedule for Completing Tasks

Tasks	Q1	Q2	Q3	Q4
Phase 1: Task 1 – Install Schneider ADMS at NREL and Identify feeders				
Phase 1: Task 2: Implement Xcel Energy system models, establish a host utility environment and initialize ADMS application engines at NREL				
Phase 1: Task 3 – ADMS GIS impedance model improvement level analysis				
Phase 1: Task 4 – Project Management and Results Dissemination				

Bubble Diagram Translation Table

Core Applications	
General Term	*Schneider Software Item*
Distribution Network Modeling	Network Model
Impedance Calculation	
Network Topology Processor	Topology Analyzer
	Temporary Elements
	Tracing
	Dynamic Equipment Rating
D-SCADA	Switching Validation
	Volt/Var Optimization
	Voltage Reduction
	Basic Switching Management (SOM)
Unbalanced Load Flow	Load Flow
Unbalanced Load Allocation	Load Profile Generator

Short-Term Applications	
General Term	*Schneider Software Item*
Unbalanced State Estimation	State Estimation
Integrated Voltage & VAr Optimization	Closed Loop VVO
	Volt/Var Optimization
	Model Readiness
Fault Location Prediction	Fault Location
Fault Location Isolation & Service Restoration	Closed Loop FLISR
	Integrated FLISR
	Element Isolation
	Supply Restoration
	Return to Normal State
	Basic Switching Management (SOM)
Study Mode & Engineering Analysis	Fault Calculation
	Snapshot
	Playback
	Thevenin Equivalent
DER Monitoring	DG Monitoring
	Electric Vehicle Monitoring
Operator Training Simulator	DMS Advanced Simulation
	Dispatcher Training Simulator

Historical Information Storage & Reporting (HISR)	Historical Trending
	Snapshot
	Playback
Medium-Term and Long-Term Applications	
General Term	*Schneider Software Item*
Network Planning	Capacitor Placement
	Voltage Regulator Placement
Contingency Analysis	Contingency Analysis
Switching, Analysis, Planning, and Execution	Work Order Management (WOM)
Mobility- Maps, Switch Management, etc.	
Forecasts of Load and Distributed Generation	Near-Term Load Forecast
	Short-Term Load Forecast
	Medium-Term Load Forecast
	Long-Term Load Forecast
Outage Management System	Core OMS
	OMS Reliability Analysis
Protection Coordination	Relay Protection
	Protection Coordination
Integration to Demand Response	Load Management (Demand Response)
	Customer Connection
Load Shedding	Load Shedding
Load Relief Load Balancing	Network Reconfiguration
	Load Relief
	Phase Balancing
Not Identified in Bubble Diagram	Large Area Restoration

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	MISO Approval
CAPX2020 Brookings	 ET-2/TL-08-1474 EL10-016	 12/29/2008 11/23/2010	Certificate of Need 5/22/2009 Route Permit MN 9/14/2010 Route Permit SD 6/14/2011	November 2011	November 2011	October 2011	March 2015	Project is in-service.	
CAPX2020 – Fargo	 E002, ET2/TL-09-246 E002, ET2/TL-09-1056	 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 is in-service.	
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	Project is in-service.	N/A

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**	**MISO Approval**
Big Stone – Brookings	EL12-063 (SD) EL13-020 (SD)	12/19/2012 6/3/2013	Facility Permit for 35 miles of planned line issued January 2007 (recertified May 10, 2013) Facility Permit for 40 miles of planned line issued February 20, 2014	June 2014	December 2016	August 2015	September 2017	Project is in-service.	December 2011 (MTEP11)
La Crosse – Madison	5-CE-142 (WI) 137-CE-160 (WI)	08/19/2013	WI Certificate of Public Convenience and Necessity 4/23/2015	May 2014	Start-June 2015 End-May 2018	August 2016	December 2018	Project is under Construction	December 2011 (MTEP11)
ADMS	E002/M-15-962	11/1/2015	6/28/2016 Certified through Biennial Grid Modification Report process	2016	N/A	2017	First quarter 2020	software development, building, and testing	N/A

CWIP Expenditures With Internal Labor Removed

NSPM Rider Project	NSPM Rider Sub Project	Eligibility Date	Pre Eligible AFUDC	Pre-2016	2016	2017	2018	2019	2020	2021	2022	Total	Internal Labor Removed		
													Previous Filing Expenditures	Dollar Variance	% Variance
ADMS	Capital	1/1/2016	-	2,351,575	2,545,495	11,275,867	12,405,796	13,562,892	2,552,541	1,980,000	1,980,000	48,654,167			
ADMS	Sub-Total ADMS			2,351,575	2,545,495	11,275,867	12,405,796	13,562,892	2,552,541	1,980,000	1,980,000	48,654,167		48,654,167	100%
Big Stone-Brookings	Land	1/1/2016		3,502,116	17,484	(62)						3,519,538			
Big Stone-Brookings	Line	1/1/2016	421,972	8,399,737	32,460,773	15,874,790	(535,799)					56,621,473			
Big Stone-Brookings	Sub	1/1/2016	4,225	3,473	3,868,759	484,267						4,360,724			
Big Stone-Brookings	Sub-Total Big Stone-Brookings		426,197	11,905,326	36,347,016	16,358,995	(535,799)					64,501,736	76,108,732	(11,606,996)	-18%
CAPX2020 Brookings	Land	1/1/2012		38,606,188	309,086	748,612						39,663,887			
CAPX2020 Brookings	Line	1/1/2012	4,092,148	356,992,977	604,229	281,315	7,032					361,977,700			
CAPX2020 Brookings	Sub	1/1/2012	38,858	53,493,601	129,583	1,493						53,663,535			
CAPX2020 Brookings	Sub-Total CAPX2020 Brookings		4,131,006	449,092,766	1,042,898	1,031,420	7,032					455,305,122	451,954,401	3,350,720	1%
CAPX2020 - La Crosse Local	Land	5/1/2009		9,753,394	(251,459)	287,377	1,114,430					10,903,742			
CAPX2020 - La Crosse Local	Line	5/1/2009		50,519,838	12,838,450	(959,953)	26,516					62,424,850			
CAPX2020 - La Crosse Local	Sub	5/1/2009		2,875,371	54,244	2,078						2,931,692			
CAPX2020 - La Crosse Local	Sub-Total CAPX2020 - La Crosse Local			63,148,603	12,641,234	(670,498)	1,140,945					76,260,285	88,008,596	(11,748,311)	-15%
CAPX2020 - La Crosse MISO	Land	5/1/2009		5,521,498	1,266,474	39,717						6,827,690			
CAPX2020 - La Crosse MISO	Line	5/1/2009	365,693	55,797,427	(499,007)	(1,435,994)						54,228,120			
CAPX2020 - La Crosse MISO	Sub	5/1/2009		14,010,725	87,679							14,098,404			
CAPX2020 - La Crosse MISO	Sub-Total CAPX2020 - La Crosse MISO		365,693	75,329,650	855,147	(1,396,276)						75,154,213	77,387,510	(2,233,297)	-3%
CAPX2020 - La Crosse MISO - WI	Land	5/1/2009		8,650,598	730,629	18,970						9,400,196			
CAPX2020 - La Crosse MISO - WI	Line	5/1/2009		108,112,599	306,237	1,435,754						109,854,589			
CAPX2020 - La Crosse MISO - WI	Sub	5/1/2009		18,379,528	11,327	3,569						18,394,425			
CAPX2020 - La Crosse MISO - WI	Sub-Total CAPX2020 - La Crosse MISO - WI			135,142,725	1,048,192	1,458,293						137,649,210	143,708,148	(6,058,938)	-4%
CAPX2020 Fargo	Land	5/1/2009		19,851,858	(81,798)	98,476						19,868,537			
CAPX2020 Fargo	Line	5/1/2009	239,382	155,778,616	198,263	24,396						156,240,657			
CAPX2020 Fargo	Sub	5/1/2009		31,343,850	(30,869)							31,312,982			
CAPX2020 Fargo	Sub-Total CAPX2020 Fargo		239,382	206,974,325	85,596	122,872						207,422,176	208,989,344	(1,567,169)	-1%
LaCrosse - Madison	Land	1/1/2016		2,099,457	2,133,474	3,940,680	1,220,378	636				9,394,625			
LaCrosse - Madison	Line	1/1/2016	1,190,165	14,814,794	18,864,689	58,870,166	46,373,418	5,785,495	128,064			146,026,793			
LaCrosse - Madison	Sub	1/1/2016	2	(3,735)	(82,976)	1,008,413	7,521,050	80,229				8,522,983			
LaCrosse - Madison	Sub-Total LaCrosse - Madison		1,190,168	16,910,517	20,915,187	63,819,259	55,114,846	5,866,359	128,064			163,944,401	181,268,259	(17,323,858)	-11%
	Total		6,352,445	960,855,487	75,480,767	91,999,933	68,132,821	19,429,251	2,680,605	1,980,000	1,980,000	1,228,891,309	1,227,424,991	1,466,318	0%

CWIP Expenditures Including Internal Labor

NSPM Rider Project	NSPM Rider Sub Project	Eligibility Date	Pre Eligible AFUDC	Pre-2016	2016	2017	2018	2019	2020	2021	2022	Total	Previous Filing Expenditures	Dollar Variance	% Variance
ADMS	Capital	1/1/2016	-	2,459,289	3,057,875	11,748,726	12,405,796	13,562,892	2,552,541	1,980,000	1,980,000	49,747,118			
ADMS	Sub-Total ADMS			2,459,289	3,057,875	11,748,726	12,405,796	13,562,892	2,552,541	1,980,000	1,980,000	49,747,118		49,747,118	100%
Big Stone-Brookings	Land	1/1/2016		3,525,565	25,421	(66)						3,550,920			
Big Stone-Brookings	Line	1/1/2016	421,972	10,312,065	36,640,914	17,368,813	(569,000)					64,174,764			
Big Stone-Brookings	Sub	1/1/2016	4,225	47,732	5,098,899	1,531,210						6,682,067			
Big Stone-Brookings	Sub-Total Big Stone-Brookings		426,197	13,885,363	41,765,234	18,899,957	(569,000)					74,407,751	81,292,182	(6,884,431)	-9%
CAPX2020 Brookings	Land	1/1/2012		38,611,622	309,086	779,480						39,700,187			
CAPX2020 Brookings	Line	1/1/2012	4,092,148	359,227,702	631,268	300,236						364,251,354			
CAPX2020 Brookings	Sub	1/1/2012	38,858	72,495,273	20,848	1,555						72,556,534			
CAPX2020 Brookings	Sub-Total CAPX2020 Brookings		4,131,006	470,334,597	961,203	1,081,270						476,508,075	477,117,871	(609,795)	0%
CAPX2020 - La Crosse Local	Land	5/1/2009		9,904,019	(199,333)	314,093	1,153,000					11,171,779			
CAPX2020 - La Crosse Local	Line	5/1/2009		52,385,795	13,242,256	(976,910)						64,651,141			
CAPX2020 - La Crosse Local	Sub	5/1/2009		3,995,326	171,011	2,175						4,168,511			
CAPX2020 - La Crosse Local	Sub-Total CAPX2020 - La Crosse Local			66,285,140	13,213,933	(660,643)	1,153,000					79,991,431	90,961,787	(10,970,357)	-14%
CAPX2020 - La Crosse MISO	Land	5/1/2009		5,581,436	1,269,010	42,145						6,892,591			
CAPX2020 - La Crosse MISO	Line	5/1/2009	365,693	59,036,750	(483,521)	(1,523,762)						57,395,159			
CAPX2020 - La Crosse MISO	Sub	5/1/2009		16,942,687								16,942,687			
CAPX2020 - La Crosse MISO	Sub-Total CAPX2020 - La Crosse MISO		365,693	81,560,873	785,489	(1,481,618)						81,230,437	82,901,602	(1,671,165)	-2%
CAPX2020 - La Crosse MISO - WI	Land	5/1/2009		8,789,159	764,338	25,214						9,578,711			
CAPX2020 - La Crosse MISO - WI	Line	5/1/2009		113,752,874	616,057	1,756,479						116,125,410			
CAPX2020 - La Crosse MISO - WI	Sub	5/1/2009		22,989,735	42,367	3,693						23,035,795			
CAPX2020 - La Crosse MISO - WI	Sub-Total CAPX2020 - La Crosse MISO - WI			145,531,768	1,422,763	1,785,386						148,739,916	152,860,011	(4,120,095)	-3%
CAPX2020 Fargo	Land	5/1/2009		19,952,549	(69,725)	107,735						19,990,560			
CAPX2020 Fargo	Line	5/1/2009	239,382	167,953,791	149,087	26,689						168,368,949			
CAPX2020 Fargo	Sub	5/1/2009		36,099,905	7,987							36,107,892			
CAPX2020 Fargo	Sub-Total CAPX2020 Fargo		239,382	224,006,246	87,349	134,424						224,467,401	226,201,829	(1,734,428)	-1%
LaCrosse - Madison	Land	1/1/2016		2,099,457	2,136,882	4,186,100	1,296,000					9,718,440			
LaCrosse - Madison	Line	1/1/2016	1,190,165	15,608,323	18,882,660	62,531,474	49,247,000	6,144,000	136,000			153,739,622			
LaCrosse - Madison	Sub	1/1/2016	2	(4,076)	(24,711)	1,105,840	7,987,100	85,200				9,149,356			
LaCrosse - Madison	Sub-Total LaCrosse - Madison		1,190,168	17,703,704	20,994,831	67,823,414	58,530,100	6,229,200	136,000			172,607,418	192,212,082	(19,604,664)	-11%
	Total		6,352,445	1,021,766,979	82,288,677	99,330,917	71,519,896	19,792,092	2,688,541	1,980,000	1,980,000	1,307,699,547	1,303,547,364	4,152,183	0%

Annual Tracker Summary

Line No:	Amounts in dollars	2016 Actual	2017 Mixed	2018 Forecast	2019 Forecast
1	ADMS	-	961,655	2,658,840	3,758,091
2	Big Stone-Brookings	2,035,350	3,639,881	5,875,499	5,693,521
3	CAPX2020 Brookings	40,530,371	39,876,460	38,797,148	37,716,564
4	CAPX2020 - La Crosse Local	4,725,929	5,209,627	5,185,816	5,069,319
5	CAPX2020 - La Crosse MISO	6,916,302	6,683,364	6,441,097	6,259,007
6	CAPX2020 - La Crosse MISO - WI	12,411,998	12,200,382	11,922,824	11,580,399
7	CAPX2020 Fargo	18,441,337	18,212,210	17,610,096	17,049,344
8	LaCrosse - Madison	1,900,767	5,751,456	10,007,548	15,388,885
9	MISO RECB Sch.26/26a	(16,092,283)	941,551	368,171	(10,957,930)
10	RES Study	-	298,509	-	-
11	ADIT Pro-Rate	-	99,981	627,974	241,014
12	Transmission Projects	70,869,772	93,875,075	99,495,014	91,798,213
13	Revenue Requirement in Base Rates (ADMS)*	-	(25,000)	(40,000)	(1,136,000)
14	TCR True-up Carryover	9,656,056	1,393,750	10,094,865	(168,768)
15	**Revenue Requirement (RR)**	**80,525,828**	**95,243,825**	**109,549,879**	**90,493,445**
16	Revenue Collections (RC)	79,132,079	85,148,960	109,718,647	90,493,445
17	**Carry Over Balance**	1,393,750	10,094,865	(168,768)	-

ADMS Software In Base Rates
Annual Revenue Requirement
2017-2019 Test Years
(000's)

		Total Company			MN Jurisdiction			
	Rate Analysis	2017	2018	2019	2017	2018	2019	
1	Average Balances:							
2	Plant Investment	-	2,217	4,434	-	1,936	3,873	
3	Depreciation Reserve	-	18	480	-	16	420	
4	CWIP	3,967	2,060	-	3,465	1,799	-	
5	Accumulated Deferred Taxes	68	434	772	59	379	674	
6	Average Rate Base = line 2 - line 3 + line 4 - line 5	3,899	3,825	3,181	3,405	3,341	2,779	
7								
8	Revenues:							
9	Interchange Agreement offset = -line 40 x line 52 x line 53				-	-	-	
10								
11	Expenses:							
12	Book Depreciation	-	37	887	-	32	775	
13	Annual Deferred Tax	40	691	(14)	35	604	(12)	
14	ITC Flow Thru	-	-	-	-	-	-	
15	Property Taxes	-	-	-	-	-	-	
16	subtotal expense = lines 12 thru 15	40	728	873	35	636	762	
17								
18	Tax Preference Items:							
19	Tax Depreciation & Removal Expense	-	1,613	740	-	1,409	647	
20	Tax Credits (enter as negative)	-	-	-	-	-	-	
21	Avoided Tax Interest	-	-	-	-	-	-	
22					-	-	-	
23	AFUDC	263	269	-	230	235	-	
24								
25	Returns:							
26	Debt Return = line 6 x (line 44 + line 45)	88	86	72	77	76	63	
27	Equity Return = line 6 x (line 46 + line 47)	188	185	154	164	161	134	
28								
29	Tax Calculations:							
30	Equity Return = line 27	188	185	154	164	161	134	
31	Taxable Expenses = lines 12 thru 14	40	728	873	35	636	762	
32	plus Tax Additions = line 21	-	-	-	-	-	-	
33	less Tax Deductions = (line 19 + line 23)	(263)	(1,882)	(740)	(230)	(1,644)	(647)	
34	subtotal	(35)	(969)	286	(30)	(847)	250	
35	Tax gross-up factor = t / (1-t) from line 50	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	
36	Current Income Tax Requirement = line 34 x line 35	(24)	(684)	202	(21)	(597)	176	
37	Tax Credit Revenue Requirement = line 20 x line 35 + line 20	-	-	-	-	-	-	
38	Total Current Tax Revenue Requirement = line 36+ line 37	(24)	(684)	202	(21)	(597)	176	
39								
40	Total Capital Revenue Requirements	29	46	1,300	25	40	1,136	
41	= line 16 + line 26 + line 27 + line 38 - line 23 + line 9							
42	O&M Expense	-	-	-	-	-	-	
43	Total Revenue Requirements	29	46	1,300	25	40	1,136	(1)

	Capital Structure	Weighted Cost	Weighted Cost	Weighted Cost	Weighted Cost	Weighted Cost	Weighted Cost
44	**Long Term Debt**	**2.2100%**	**2.2100%**	**2.1800%**	**2.2100%**	**2.2100%**	**2.1800%**
45	**Short Term Debt**	**0.0500%**	**0.0500%**	**0.0700%**	**0.0500%**	**0.0500%**	**0.0700%**
46	**Preferred Stock**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
47	**Common Equity**	**4.8300%**	**4.8300%**	**4.8300%**	**4.8300%**	**4.8300%**	**4.8300%**
48	**Required Rate of Return**	**7.0900%**	**7.0900%**	**7.0800%**	**7.0900%**	**7.0900%**	**7.0800%**
49	**PT Rate**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
50	**Tax Rate (MN)**	**41.3700%**	**41.3700%**	**41.3700%**	**41.3700%**	**41.3700%**	**41.3700%**
51	**MN JUR Electric Intangible Composite**	**87.3467%**	**87.3467%**	**87.3467%**	**87.3467%**	**87.3467%**	**87.3467%**
52	**IA Demand**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**

(1) Revenue Requirements are spread evenly across 12 months in Attachments 6-9

2016 Tracker

Line No	Amounts in dollars	Carryover	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
			Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual
1	ADMS		-	-	-	-	-	-	-	-	-	-	-	-	-
2	Big Stone-Brookings		60,400	64,417	85,756	111,102	125,790	141,985	164,223	203,671	239,235	259,778	281,195	297,799	2,035,350
3	CAPX2020 Brookings		3,368,803	3,367,154	3,367,571	3,671,063	3,652,675	3,326,456	3,315,209	3,306,648	3,295,668	3,287,729	3,287,284	3,284,112	40,530,371
4	CAPX2020 - La Crosse Local		361,340	370,874	380,027	390,772	396,660	406,035	412,185	411,840	414,103	407,757	393,732	380,603	4,725,929
5	CAPX2020 - La Crosse MISO		578,893	578,251	578,872	579,117	577,942	578,304	578,667	577,764	576,745	574,861	570,388	566,500	6,916,302
6	CAPX2020 - La Crosse MISO - WI		1,038,184	1,034,670	1,033,402	1,035,389	1,035,161	1,037,954	1,041,719	1,038,812	1,039,671	1,038,648	1,024,675	1,013,713	12,411,998
7	CAPX2020 Fargo		1,566,098	1,560,753	1,540,603	1,542,528	1,542,981	1,539,206	1,536,618	1,534,981	1,530,998	1,522,946	1,515,939	1,507,686	18,441,337
8	LaCrosse - Madison		109,871	103,303	111,347	123,530	133,335	140,024	146,658	159,711	177,299	206,264	235,943	253,482	1,900,767
9	MISO RECB Sch.26/26a		(1,854,736)	(1,710,572)	(1,715,530)	(1,260,289)	(931,525)	(1,370,589)	(965,333)	(84,442)	(1,941,590)	(1,383,834)	(1,030,419)	(1,843,425)	(16,092,283)
10	RES Study		-	-	-	-	-	-	-	-	-	-	-	-	-
11	ADIT Pro-Rate		-	-	-	-	-	-	-	-	-	-	-	-	-
12	Transmission Projects		5,228,851	5,368,850	5,382,048	6,193,212	6,533,019	5,799,375	6,229,947	7,148,985	5,332,129	5,914,149	6,278,738	5,460,470	70,869,772
13	Revenue Requirement in Base Rates (ADMS)		-	-	-	-	-	-	-	-	-	-	-	-	-
14	TCR True-up Carryover	9,656,056	9,656,056												9,656,056
15	**Revenue Requirement (RR)**		**14,884,907**	**5,368,850**	**5,382,048**	**6,193,212**	**6,533,019**	**5,799,375**	**6,229,947**	**7,148,985**	**5,332,129**	**5,914,149**	**6,278,738**	**5,460,470**	**80,525,828**
16	Revenue Collections (RC)		6,417,656	6,174,765	6,542,002	5,693,721	6,144,809	6,873,154	7,300,626	8,457,529	7,204,395	6,311,529	5,781,628	6,230,265	79,132,079
17	Monthly RR - RC		8,467,251	(805,915)	(1,159,954)	499,491	388,210	(1,073,779)	(1,070,679)	(1,308,544)	(1,872,266)	(397,380)	497,110	(769,795)	
18	Balance (RR - RC + Cumulative CC)		8,467,251	7,661,336	6,501,381	7,000,872	7,389,083	6,315,304	5,244,624	3,936,081	2,063,815	1,666,435	2,163,545	1,393,750	

2017 Tracker

Line No	Amounts in dollars	Carryover	Jan-17 Actual	Feb-17 Actual	Mar-17 Actual	Apr-17 Actual	May-17 Actual	Jun-17 Actual	Jul-17 Actual	Aug-17 Forecast	Sep-17 Forecast	Oct-17 Forecast	Nov-17 Forecast	Dec-17 Forecast	Annual Total Mixed
1	ADMS		41,687	42,590	45,965	49,090	51,652	61,842	72,727	92,097	114,978	124,302	130,760	133,966	961,655
2	Big Stone-Brookings		279,720	269,741	265,365	262,425	263,452	256,507	322,461	334,821	337,489	334,391	329,816	383,693	3,639,881
3	CAPX2020 Brookings		3,366,327	3,352,523	3,342,034	3,337,513	3,330,662	3,322,657	3,315,629	3,313,445	3,310,734	3,302,913	3,294,947	3,287,077	39,876,460
4	CAPX2020 - La Crosse Local		447,046	443,943	441,569	436,508	431,163	430,086	430,261	430,592	429,589	428,788	429,706	430,377	5,209,627
5	CAPX2020 - La Crosse MISO		572,708	571,424	570,146	562,452	554,816	553,774	552,673	551,473	550,274	549,074	547,874	546,675	6,683,364
6	CAPX2020 - La Crosse MISO - WI		1,027,733	1,028,583	1,028,598	1,024,175	1,019,335	1,016,372	1,013,393	1,010,717	1,008,149	1,008,020	1,007,777	1,007,530	12,200,382
7	CAPX2020 Fargo		1,539,316	1,535,236	1,531,440	1,527,739	1,523,968	1,520,090	1,516,006	1,511,915	1,507,799	1,503,683	1,499,567	1,495,451	18,212,210
8	LaCrosse - Madison		254,169	271,119	311,361	355,558	389,973	439,915	484,747	531,996	592,122	656,852	710,029	753,616	5,751,456
9	MISO RECB Sch.26/26a		3,471,262	(200,263)	95,629	(432,006)	(305,657)	301,642	(139,915)	(299,321)	(632,601)	(279,850)	(761,419)	124,049	941,551
10	RES Study		24,876	24,876	24,876	24,876	24,876	24,876	24,876	24,876	24,876	24,876	24,876	24,876	298,509
11	ADIT Pro-Rate		-	-	-	-	-	-	33,112	26,447	19,996	13,331	6,880	215	99,981
12	Transmission Projects		11,024,844	7,339,771	7,656,984	7,148,329	7,284,241	7,927,761	7,625,970	7,529,058	7,263,404	7,666,379	7,220,812	8,187,523	93,875,075
13	Revenue Requirement in Base Rates (ADMS)		(2,083)	(2,083)	(2,083)	(2,083)	(2,083)	(2,083)	(2,083)	(2,083)	(2,083)	(2,083)	(2,083)	(2,083)	(25,000)
14	TCR True-up Carryover	1,393,750	1,393,750	-	-	-	-	-	-	-	-	-	-	-	1,393,750
15	**Revenue Requirement (RR)**		**12,416,511**	**7,337,688**	**7,654,900**	**7,146,246**	**7,282,157**	**7,925,678**	**7,623,886**	**7,526,975**	**7,261,321**	**7,664,295**	**7,218,729**	**8,185,440**	**95,243,825**
16	Revenue Collections (RC)		6,919,421	5,979,677	7,155,930	6,117,190	6,739,039	7,683,379	7,992,768	8,492,753	7,245,801	6,857,095	6,629,901	7,336,005	85,148,960
17	Monthly RR - RC		5,497,090	1,358,011	498,970	1,029,057	543,118	242,299	(368,882)	(965,779)	15,520	807,200	588,828	849,435	
18	Balance (RR - RC + Cumulative CC)		5,497,090	6,855,100	7,354,070	8,383,127	8,926,245	9,168,543	8,799,661	7,833,882	7,849,402	8,656,602	9,245,430	10,094,865	

2018 Tracker

Line No	Amounts in dollars	Carryover	Jan-18 Forecast	Feb-18 Forecast	Mar-18 Forecast	Apr-18 Forecast	May-18 Forecast	Jun-18 Forecast	Jul-18 Forecast	Aug-18 Forecast	Sep-18 Forecast	Oct-18 Forecast	Nov-18 Forecast	Dec-18 Forecast	Annual Total Forecast
1	ADMS		175,391	207,568	210,970	214,568	218,279	221,713	224,931	228,172	232,897	237,709	241,418	245,225	2,658,840
2	Big Stone-Brookings		499,433	496,699	493,920	491,903	490,745	489,588	488,430	487,272	486,114	484,956	483,799	482,641	5,875,499
3	CAPX2020 Brookings		3,274,883	3,267,305	3,259,704	3,252,102	3,244,500	3,236,899	3,229,297	3,221,695	3,214,093	3,206,492	3,198,890	3,191,288	38,797,148
4	CAPX2020 - La Crosse Local		434,518	433,415	432,220	431,026	429,832	432,448	435,056	433,845	432,633	431,463	430,289	429,071	5,185,816
5	CAPX2020 - La Crosse MISO		543,795	542,516	541,236	539,957	538,677	537,398	536,118	534,839	533,560	532,280	531,001	529,721	6,441,097
6	CAPX2020 - La Crosse MISO - WI		1,006,807	1,004,400	1,001,993	999,586	997,179	994,772	992,365	989,958	987,551	985,144	982,737	980,330	11,922,824
7	CAPX2020 Fargo		1,489,094	1,485,169	1,481,244	1,477,320	1,473,395	1,469,470	1,465,546	1,461,621	1,457,696	1,453,772	1,449,847	1,445,922	17,610,096
8	LaCrosse - Madison		661,892	702,777	735,374	763,233	788,084	821,253	859,865	892,140	916,681	936,024	949,342	980,882	10,007,548
9	MISO RECB Sch.26/26a		71,166	(179,227)	362,682	(124,518)	395,014	174,005	253,722	(164,858)	158,382	(2,029)	(271,397)	(304,771)	368,171
10	RES Study		-	-	-	-	-	-	-	-	-	-	-	-	-
11	ADIT Pro-Rate		103,682	95,016	85,422	76,137	66,542	57,257	47,663	38,068	28,783	19,189	9,904	309	627,974
12	Transmission Projects		8,260,661	8,055,638	8,604,765	8,121,314	8,642,249	8,434,803	8,532,992	8,122,752	8,448,391	8,285,000	8,005,829	7,980,620	99,495,014
13	Revenue Requirement in Base Rates (ADMS)		(3,333)	(3,333)	(3,333)	(3,333)	(3,333)	(3,333)	(3,333)	(3,333)	(3,333)	(3,333)	(3,333)	(3,333)	(40,000)
14	TCR True-up Carryover	10,094,865	10,094,865	-	-	-	-	-	-	-	-	-	-	-	10,094,865
15	**Revenue Requirement (RR)**		**18,352,193**	**8,052,305**	**8,601,432**	**8,117,981**	**8,638,916**	**8,431,469**	**8,529,659**	**8,119,419**	**8,445,058**	**8,281,666**	**8,002,496**	**7,977,286**	**109,549,879**
16	Revenue Collections (RC)		9,609,467	8,302,620	8,833,476	7,698,833	8,516,858	9,568,839	11,113,143	10,734,865	9,109,125	8,610,379	8,344,567	9,276,475	109,718,647
17	Monthly RR - RC		8,742,726	(250,315)	(232,044)	419,148	122,058	(1,137,370)	(2,583,484)	(2,615,446)	(664,067)	(328,713)	(342,071)	(1,299,189)	
18	Balance (RR - RC + Cumulative CC)		8,742,726	8,492,411	8,260,367	8,679,514	8,801,572	7,664,203	5,080,718	2,465,272	1,801,205	1,472,492	1,130,421	(168,768)	

2019 Tracker

Line No	Amounts in dollars	Carryover	Jan-19 Forecast	Feb-19 Forecast	Mar-19 Forecast	Apr-19 Forecast	May-19 Forecast	Jun-19 Forecast	Jul-19 Forecast	Aug-19 Forecast	Sep-19 Forecast	Oct-19 Forecast	Nov-19 Forecast	Dec-19 Forecast	Annual Total Forecast
1	ADMS		261,188	270,458	279,642	289,522	299,837	309,546	318,734	327,488	336,156	345,085	354,970	365,465	3,758,091
2	Big Stone-Brookings		480,741	479,599	478,457	477,315	476,173	475,031	473,889	472,747	471,605	470,463	469,322	468,180	5,693,521
3	CAPX2020 Brookings		3,182,785	3,175,560	3,168,335	3,161,110	3,153,885	3,146,660	3,139,435	3,132,210	3,124,984	3,117,759	3,110,534	3,103,309	37,716,564
4	CAPX2020 - La Crosse Local		428,454	427,361	426,268	425,175	424,083	422,990	421,897	420,804	419,711	418,618	417,525	416,432	5,069,319
5	CAPX2020 - La Crosse MISO		528,285	527,067	525,848	524,630	523,412	522,193	520,975	519,756	518,538	517,319	516,101	514,883	6,259,007
6	CAPX2020 - La Crosse MISO - WI		977,641	975,349	973,056	970,764	968,472	966,179	963,887	961,595	959,303	957,010	954,718	952,426	11,580,399
7	CAPX2020 Fargo		1,441,546	1,437,770	1,433,994	1,430,218	1,426,442	1,422,667	1,418,891	1,415,115	1,411,339	1,407,563	1,403,787	1,400,011	17,049,344
8	LaCrosse - Madison		1,277,732	1,280,463	1,280,450	1,279,067	1,277,976	1,279,330	1,282,412	1,285,486	1,287,680	1,288,207	1,286,518	1,283,563	15,388,885
9	MISO RECB Sch.26/26a		(907,968)	(1,064,752)	(481,343)	(954,133)	(462,649)	(865,825)	(891,199)	(1,329,017)	(801,063)	(889,050)	(1,139,617)	(1,171,314)	(10,957,930)
10	RES Study		-	-	-	-	-	-	-	-	-	-	-	-	-
11	ADIT Pro-Rate		39,793	36,467	32,784	29,221	25,539	21,975	18,293	14,610	11,047	7,365	3,801	119	241,014
12	Transmission Projects		7,710,196	7,545,341	8,117,492	7,632,889	8,113,169	7,700,745	7,667,213	7,220,795	7,739,300	7,640,340	7,377,659	7,333,073	91,798,213
13	Revenue Requirement in Base Rates (ADMS)		(94,667)	(94,667)	(94,667)	(94,667)	(94,667)	(94,667)	(94,667)	(94,667)	(94,667)	(94,667)	(94,667)	(94,667)	(1,136,000)
14	TCR True-up Carryover	(168,768)	(168,768)	-	-	-	-	-	-	-	-	-	-	-	(168,768)
15	**Revenue Requirement (RR)**		**7,446,762**	**7,450,674**	**8,022,825**	**7,538,222**	**8,018,502**	**7,606,079**	**7,572,547**	**7,126,128**	**7,644,634**	**7,545,673**	**7,282,993**	**7,238,407**	**90,493,445**
16	Revenue Collections (RC)		7,446,762	7,450,674	8,022,825	7,538,222	8,018,502	7,606,079	7,572,547	7,126,128	7,644,634	7,545,673	7,282,993	7,238,407	90,493,445
17	Monthly RR - RC		-	-	-	-	-	-	-	-	-	-	-	-	
18	Balance (RR - RC + Cumulative CC)		-	-	-	-	-	-	-	-	-	-	-	-	

Northern States Power Company
State of Minnesota
Transmission Cost Recovery Rider
2017 Revenue Calculation

		Forecast Revenue (2)					kWh Sales by Customer Group (3)					kW Demand
			Customer Groups					Customer Groups				
		Total Revenue	Residential	Commercial Non-Demand	Demand	Street Lighting	Retail Sales	Residential	Commercial Non-Demand	Demand	Street Lighting	Demand Group
Adjustment Factors												
2016 TCR Rates (1)			**$0.003503**	**$0.003384**	**$1.017**	**$0.000000**						
17-Jan	**Actual**	6,919,421	2,883,176	281,134	3,755,110	-	2,675,819,972	891,752,579	94,375,354	1,676,593,958	13,098,081	4,288,512
17-Feb	**Actual**	5,979,677	2,170,596	235,704	3,573,377	-	2,216,718,072	649,204,727	76,303,157	1,478,608,584	12,601,604	3,782,091
17-Mar	**Actual**	7,155,930	2,445,242	270,477	4,440,211	-	2,475,235,478	699,082,117	82,565,782	1,681,823,358	11,764,222	4,301,889
17-Apr	**Actual**	6,117,190	1,927,665	218,344	3,971,180	-	2,148,153,892	550,792,029	66,384,206	1,520,426,697	10,550,959	3,889,057
17-May	**Actual**	6,739,039	1,965,986	219,758	4,553,295	-	2,302,589,176	561,696,089	66,651,488	1,665,774,196	8,467,403	4,260,837
17-Jun	**Actual**	7,683,379	2,547,029	238,012	4,898,338	-	2,594,150,703	727,539,841	71,904,305	1,787,334,777	7,371,780	4,571,773
17-Jul	**Actual**	7,992,768	2,844,312	247,774	4,900,682	-	2,856,538,958	812,337,820	74,696,675	1,962,085,537	7,418,926	5,018,763
17-Aug	**Actual**	8,492,753	3,130,969	265,573	5,096,212	-	2,946,312,176	894,244,735	80,084,102	1,963,610,415	8,372,924	5,022,664
17-Sep	**2016 Rate**	7,245,801	2,381,479	233,492	4,630,830	-	2,540,041,437	679,839,854	68,998,777	1,780,160,155	11,042,651	4,553,422
17-Oct	**2016 Rate**	6,857,095	2,135,628	222,437	4,499,030	-	2,417,950,067	609,656,877	65,731,946	1,729,494,562	13,066,681	4,423,825
17-Nov	**2016 Rate**	6,629,901	2,281,806	217,534	4,130,561	-	2,317,239,078	651,386,247	64,283,234	1,587,849,197	13,720,400	4,061,515
17-Dec	**2016 Rate**	7,336,005	2,718,571	258,083	4,359,351	-	2,544,337,859	776,069,403	76,265,605	1,675,799,580	16,203,271	4,286,481
Total Jan-Dec		**$ 85,148,960**	**$ 29,432,459**	**$ 2,908,323**	**$ 52,808,178**	**$ -**	**30,035,086,867**	**8,503,602,316**	**888,244,631**	**20,509,561,018**	**133,678,902**	**52,460,829**

Notes:

(1) 2016 TCR Adjustment Factors by customer group are those approved in Docket No. E002/M-15-891 and implemented on February 1, 2017.

(2) 2017 estimated revenues to be recovered under the TCR Rate Rider are calculated by multiplying the TCR Adjustment Factor, listed above, by the forecast sales for the month by customer group.

(3) Sales by customer group are based on the 2017 State of Minnesota budget sales for 2017 by billing month including Interdepartmental in the Demand Group.

Northern States Power Company
State of Minnesota
Transmission Cost Recovery Rider
2018 Revenue Calculation

	Forecast Revenue (2)					kWh Sales by Customer Group (3)					kW Demand
		Customer Groups					Customer Groups				
	Total Revenue	Residential	Commercial Non-Demand	Demand	Street Lighting	Retail Sales	Residential	Commercial Non-Demand	Demand	Street Lighting	Demand Group
Adjustment Factors											
2018 TCR Rates (1)		**$0.004645**	**$0.004102**	**$1.274**	**$0.000000**						
18-Jan	9,609,467	3,801,973	352,589	5,454,905	-	2,594,773,497	818,508,806	85,955,395	1,673,936,483	16,372,813	4,281,715
18-Feb	8,302,620	3,073,872	300,877	4,927,871	-	2,261,065,424	661,759,303	73,348,737	1,512,206,515	13,750,869	3,868,030
18-Mar	8,833,476	3,033,772	333,841	5,465,863	-	2,425,331,531	653,126,386	81,384,927	1,677,299,071	13,521,148	4,290,316
18-Apr	7,698,833	2,486,100	266,120	4,946,613	-	2,129,340,361	535,220,710	64,875,562	1,517,957,791	11,286,297	3,882,742
18-May	8,516,858	2,764,520	277,609	5,474,729	-	2,352,992,540	595,160,352	67,676,560	1,680,019,852	10,135,777	4,297,275
18-Jun	9,568,839	3,556,218	295,343	5,717,278	-	2,601,408,184	765,601,365	71,999,783	1,754,450,316	9,356,721	4,487,659
18-Jul	11,113,143	4,398,917	334,242	6,379,984	-	2,995,556,055	947,021,910	81,482,622	1,957,813,653	9,237,870	5,007,836
18-Aug	10,734,865	4,127,685	327,591	6,279,589	-	2,904,155,190	888,629,692	79,861,212	1,927,005,753	8,658,533	4,929,034
18-Sep	9,109,125	3,142,272	283,726	5,683,127	-	2,499,917,009	676,484,827	69,167,743	1,743,970,532	10,293,906	4,460,853
18-Oct	8,610,379	2,817,296	270,611	5,522,472	-	2,378,927,973	606,522,183	65,970,583	1,694,670,516	11,764,691	4,334,750
18-Nov	8,344,567	3,012,731	264,637	5,067,199	-	2,280,766,241	648,596,500	64,514,022	1,554,962,036	12,693,683	3,977,394
18-Dec	9,276,475	3,604,629	313,925	5,357,921	-	2,511,566,955	776,023,415	76,529,775	1,644,175,129	14,838,635	4,205,589
Total Jan-Dec	**$ 109,718,647**	**$ 39,819,985**	**$ 3,621,111**	**$ 66,277,551**	**$ -**	**29,935,800,959**	**8,572,655,449**	**882,766,920**	**20,338,467,648**	**141,910,942**	**52,023,194**

Notes:

(1) 2018 TCR Adjustment Factors by customer group are calculated on Attachment 9, page 3.
(2) 2018 estimated revenues to be recovered under the TCR Rate Rider are calculated by multiplying the TCR Adjustment Factor, listed above, by the forecast sales for the month by customer group.
(3) Sales by customer group are based on the 2017 State of Minnesota budget sales for 2018 by billing month including Interdepartmental in the Demand Group.

			Customer Groups				
		Retail	**Residential**	**Commercial Non-Demand**	**Demand**	**Street Lighting**	**Total**
Transmission Demand Allocator	D10S	100.00%	36.14%	3.28%	60.59%	0.00%	100.00%
Sales Allocator	E99	100.00%	28.47%	2.92%	68.06%	0.55%	100.00%
Group Weighting Factor (1)	**Fixed Ratio**	**1.0000**	**1.2694**	**1.1210**	**0.8902**	**0.0000**	**1.0000**
	MN kWh retail Sales	**29,935,800,959**	8,572,655,449	882,766,920	20,338,467,648	141,910,942	29,935,800,959
	MN kW Demand				52,023,194		
State of Mn Cost per kWh	**Total Sales/Costs**	**$0.003659**					
	MN retail Cost	**$109,549,879**	$39,819,985	$3,621,110	$66,262,728	$0	$109,703,822
		Basis					
TCR Adjustment Factor (2)		**per kWh**	**$0.004645**	**$0.004102**		**$0.000000**	
		per kW			**$1.274**		

Notes:

1) The Group Weighting Factors are calculated by dividing the transmission demand allocation percentage for each customer group, by the corresponding sales allocation percentage for the same customer group. The transmission demand and sales allocation percentages were established in Xcel Energy's last approved electric rate case, Docket No. E002/GR-15-826.

2) The TCR Adjustment Factors by customer group are determined by multiplying each Group Weighting Factor by the average retail cost per kWh. The average retail cost per kWh is calculated by using the Minnesota electric retail cost divided by the annual Minnesota Retail Sales.

Key Inputs

Line No	**Capital Structure**									
1			**2016 Compliance**			**2017**			**2018**	
2	Capital Structure	Cost	Ratio	WACC	Cost	Ratio	WACC	Cost	Ratio	WACC
3	Long Term Debt	4.94%	45.61%	2.25%	4.81%	46.04%	2.21%	4.77%	46.41%	2.21%
4	Short Term Debt	1.12%	1.89%	0.02%	3.57%	1.46%	0.05%	4.45%	1.09%	0.05%
5	Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
6	Common Equity	9.72%	52.50%	5.10%	10.00%	52.50%	5.25%	10.00%	52.50%	5.25%
7	**Required Rate of Return**			7.37%			7.51%			7.51%
8	**(Rates and Ratios from Settlement in Docket E002/GR-15-826, ROE as discussed in TCR petition)**									
9										
10	**Property Tax Rates**									
11	Property Tax Rate			1.714%			1.664%			1.664%
12										
13	**Income Tax Rates**									
14	Federal Tax Rate			35.00%			35.00%			35.00%
15	StateTax Rate			9.80%			9.80%			9.80%
16	State Composite Income Tax Rate			41.3700%			41.3700%			41.3700%
17	Company Composite Income Tax Rate			40.8097%			40.8468%			40.8468%
18										
19	**OATT**									
20	Annual OATT Credit Factor			20.99%			24.00%			22.70%
21										
22	**Allocators (As Approved in Docket E002/GR-15-826)**									
23	MN 12-month CP demand (Electric Demand)			87.3461% *			87.3461% *			87.3461% *
24	NSPM 36-month CP demand (Interchange Electric)			84.1349%			84.2464% **			84.0798%
25	Jurisdictional Allocator			73.4886%			73.5859%			73.4404%
26	* As Approved in Docket E002/GR-15-826									
27	** As Approved in ER17-1377									
28										
29	**Book Depreciation Lives**									
30	Land			0			0			0
31	Line			62.72			62.65			62.65
32	Sub			56.56			56.74			56.74
33	ADMS			n/a			9.00			9.00
34										
35	**Net Salvage %**									
36	Land			0.00%			0.00%			0.00%
37	Line			-32.51%			-32.55%			-32.55%
38	Sub			-9.54%			-9.39%			-9.39%
39	ADMS			n/a			0.00%			0.00%
40										
41	**Book Depreciation Rates**									
42	Land			0			0			0
43	Line			2.11260%			2.1158%			2.1158%
44	Sub			1.9366%			1.9280%			1.9280%
45	ADMS			n/a			11.1110%			11.1110%

Northern States Power Company
Transmission Revenue From Others
NSP Revenue Credits for FERC Account 456

2017 Forecast
Amounts in dollars

Line No.	SAP Account	Description		Total 2017	Revenue included in OATT Credit	Revenue Excluded in OATT Credit
1	4140001	PTP - Firm	MISO	9,900,615		9,900,615
2	4140001	PTP - Non Firm	MISO	331,567		331,567
3	4140051	Network	MISO	31,228,420	31,228,420	
4	4140051	Network - Whls	MISO	-	-	
5	4140201	Sch 1 - Sch, Sys Ctrl & D	MISO	1,245,766	1,245,766	
6	4140201	Sch 1 - Sch, Sys Ctrl & D - Whls	MISO		-	
7	4140211	Sch 2 - Reactive Supply	MISO	8,585,862	8,585,862	
8	4140211	Sch 2 - Reactive Supply - Whls	MISO			
9	4140251	Sch 24 - Bal Auth	MISO	1,124,971	1,124,971	
10		Other RTO GFA Revenue	MISO			
11	4140351	Trans Expansion Plan Att GG	MISO	80,005,520		80,005,520
13	4140351	Trans Expansion Plan Att GG - True Up	MISO		-	
12	4140351	Trans Expansion Plan Att MM Brookings	MISO	61,152,510		61,152,510
14	4140351	Trans Expansion Plan Att MM - True Up	MISO		-	
15	4140051	Joint Pricing Zone - GRE	JPZ	39,530,908	39,530,908	
16	4140051	Joint Pricing Zone - SMMPA	JPZ	6,927,940	6,927,940	
17	4140051	Joint Pricing Zone - MRES	JPZ	4,233,741	4,233,741	
18	4140211	Sch 2 - Reactive Supply	JPZ		-	
19	4140211	Firm Transmission	GFA's			
20	4140211	Sch 1-Sch, Sys Ctrl & D	GFA's			
21	4140211	Sch 2 - Reactive Supply	GFA's			
22		MISO Schedule 10 Passthrough	GFA's			
23	4140101	Facilities	MISO			-
24	4140101	Facilities				-
25	4140101	Contracts - SD State Pen		13,532		13,532
26	4140101	Contracts - WPPI		40,320		40,320
27	4140101	Contracts - UND		61,499		61,499
28	4140101	Contracts - Granite Falls		15,527		15,527
29	4140101	Contracts - EGF		48,735		48,735
30	4140101	Contracts - Sioux Falls		176,870		176,870
31		GRE 500kV tsmn O&M				
32		Marshall TOPS				
33		Total NSP Revenue		244,624,304	92,877,609	151,746,695

Line 36 Attachment O - 2017 Forecast	92,877,609
Line 1 Attachment O - 2017 Forecast	387,025,425
2016 OATT Credit Factor = Line 36 / Line 1	24.00%

2018 - 2022 Forecast

Amounts in dollars

Line No.	SAP Account	Description		Total 2018	Revenue included in OATT Credit	Revenue Excluded in OATT Credit
1	4140001	PTP - Firm	MISO	10,834,950		10,834,950
2	4140001	PTP - Non Firm	MISO	337,703		337,703
3	4140051	Network	MISO	33,362,758	33,362,758	
4	4140051	Network - Whls	MISO	-	-	
5	4140201	Sch 1 - Sch, Sys Ctrl & D	MISO	1,323,065	1,323,065	
6	4140201	Sch 1 - Sch, Sys Ctrl & D - Whls	MISO		-	
7	4140211	Sch 2 - Reactive Supply	MISO	8,548,880	8,548,880	
8	4140211	Sch 2 - Reactive Supply - Whls	MISO			
9	4140251	Sch 24 - Bal Auth	MISO	1,155,697	1,155,697	
10		Other RTO GFA Revenue	MISO			
11	4140351	Trans Expansion Plan Att GG	MISO	73,982,101		73,982,101
13	4140351	Trans Expansion Plan Att GG - True Up	MISO		-	
12	4140351	Trans Expansion Plan Att MM Brookings	MISO	71,496,170		71,496,170
14	4140351	Trans Expansion Plan Att MM - True Up	MISO		-	
15	4140051	Joint Pricing Zone - GRE	JPZ	36,989,516	36,989,516	
16	4140051	Joint Pricing Zone - SMMPA	JPZ	6,438,881	6,438,881	
17	4140051	Joint Pricing Zone - MRES	JPZ	3,939,460	3,939,460	
18	4140211	Sch 2 - Reactive Supply	JPZ	126,983	126,983	
19	4140211	Firm Transmission	GFA's			
20	4140211	Sch 1-Sch, Sys Ctrl & D	GFA's			
21	4140211	Sch 2 - Reactive Supply	GFA's			
22		MISO Schedule 10 Passthrough	GFA's			
23	4140101	Facilities	MISO			-
24	4140101	Facilities				-
25	4140101	Contracts - SD State Pen		13,532		13,532
26	4140101	Contracts - WPPI		40,320		40,320
27	4140101	Contracts - UND		63,984		63,984
28	4140101	Contracts - Granite Falls		16,477		16,477
29	4140101	Contracts - EGF		51,717		51,717
30	4140101	Contracts - Sioux Falls		188,556		188,556
31		Other (Kasota,Shakopee,St James)		46,888	46,888	
32		Marshall TOPS				
33		Total NSP Revenue		248,957,639	91,932,129	157,025,510

Line 36 Attachment O - 2018 - 2022 Fcst	91,932,129
Line 1 Attachment O - 2018 - 2022 Fcst	404,934,927
2016 OATT Credit Factor = Line 36 / Line 1	22.70%

Regional Expansion Criteria and Benefits

Amounts in dollars

Line No.		2016 Actual	Jan-17 Actual	Feb-17 Actual	Mar-17 Actual	Apr-17 Actual	May-17 Actual	Jun-17 Actual	Jul-17 Actual	Aug-17 Actual	Sep-17 Forecast	Oct-17 Forecast	Nov-17 Forecast	Dec-17 Forecast	2017 Mixed
	Revenue														
1	Schedule 26	88,851,417	(666,456)	5,846,547	4,560,540	5,538,128	6,520,883	7,146,771	8,721,867	7,774,463	7,516,785	5,586,051	5,731,857	6,319,852	70,597,289
2	Schedule 26(a)	61,483,437	(660,405)	4,111,633	4,426,067	4,133,142	3,816,951	5,104,005	5,585,601	5,675,185	5,260,393	4,755,329	4,699,257	4,032,060	50,939,219
3	Total Revenue	150,334,855	(1,326,861)	9,958,180	8,986,607	9,671,270	10,337,835	12,250,777	14,307,468	13,449,649	12,777,178	10,341,380	10,431,114	10,351,912	121,536,508
4															
5															
6	**Expense**														
7	Schedule 26	84,414,607	866,177	5,426,218	4,993,143	5,108,739	6,006,077	7,826,231	8,804,289	7,689,228	7,571,848	5,933,250	5,476,460	6,828,873	72,530,533
8	Schedule 26(a)	44,022,575	2,524,252	4,259,813	4,123,420	3,975,455	3,916,383	4,834,464	5,313,040	5,353,657	4,345,654	4,027,827	3,919,920	3,691,616	50,285,500
9	Total Expense	128,437,182	3,390,429	9,686,032	9,116,563	9,084,194	9,922,461	12,660,695	14,117,330	13,042,884	11,917,501	9,961,077	9,396,380	10,520,488	122,816,033
10															
11															
12	Total	(21,897,673)	4,717,290	(272,148)	129,955	(587,077)	(415,374)	409,918	(190,138)	(406,764)	(859,676)	(380,303)	(1,034,734)	168,577	1,279,525
13	Demand Allocator - State of MN Jur.	73.4886%	73.5859%	73.5859%	73.5859%	73.5859%	73.5859%	73.5859%	73.5859%	73.5859%	73.5859%	73.5859%	73.5859%	73.5859%	73.5859%
14	RECB Revenue Requirement	(16,092,283)	3,471,262	(200,263)	95,629	(432,006)	(305,657)	301,642	(139,915)	(299,321)	(632,601)	(279,850)	(761,419)	124,049	941,551
15	RECB in Base Rates	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	**Net RECB Revenue Requirements**	**(16,092,283)**	**3,471,262**	**(200,263)**	**95,629**	**(432,006)**	**(305,657)**	**301,642**	**(139,915)**	**(299,321)**	**(632,601)**	**(279,850)**	**(761,419)**	**124,049**	**941,551**

Regional Expansion Criteria and Benefits

Amounts in dollars

Line No.		Jan-18 Forecast	Feb-18 Forecast	Mar-18 Forecast	Apr-18 Forecast	May-18 Forecast	Jun-18 Forecast	Jul-18 Forecast	Aug-18 Forecast	Sep-18 Forecast	Oct-18 Forecast	Nov-18 Forecast	Dec-18 Forecast	2018 Forecast
	Revenue													
1	Schedule 26	5,971,215	5,728,453	5,362,921	5,102,213	5,898,754	6,956,676	7,843,061	7,676,191	6,796,509	5,218,923	5,533,116	5,894,070	73,982,101
2	Schedule 26(a)	6,091,027	5,487,848	5,245,434	4,934,363	5,208,124	6,054,538	6,650,977	6,791,827	5,722,527	5,303,999	5,161,904	4,861,264	67,513,833
3	Total Revenue	12,062,242	11,216,301	10,608,355	10,036,575	11,106,879	13,011,214	14,494,038	14,468,019	12,519,036	10,522,922	10,695,020	10,755,334	141,495,934
4														
5														
6	**Expense**													
7	Schedule 26	5,869,510	5,094,740	5,438,856	4,857,980	6,333,307	7,478,419	8,388,297	8,023,363	6,954,951	5,295,343	5,162,265	5,910,202	74,807,232
8	Schedule 26(a)	6,289,634	5,877,518	5,663,343	5,009,046	5,311,442	5,769,728	6,451,221	6,220,177	5,779,745	5,224,817	5,163,208	4,430,141	67,190,021
9	Total Expense	12,159,145	10,972,258	11,102,199	9,867,026	11,644,749	13,248,147	14,839,518	14,243,540	12,734,696	10,520,160	10,325,473	10,340,343	141,997,253
10														
11														
12	Total	96,902	(244,043)	493,845	(169,550)	537,870	236,933	345,480	(224,479)	215,660	(2,763)	(369,547)	(414,991)	501,319
13	Demand Allocator - State of MN Jur.	73.4404%	73.4404%	73.4404%	73.4404%	73.4404%	73.4404%	73.4404%	73.4404%	73.4404%	73.4404%	73.4404%	73.4404%	73.4404%
14	RECB Revenue Requirement	71,166	(179,227)	362,682	(124,518)	395,014	174,005	253,722	(164,858)	158,382	(2,029)	(271,397)	(304,771)	368,171
15	RECB in Base Rates	-	-	-	-	-	-	-	-	-	-	-	-	-
16	**Net RECB Revenue Requirements**	**71,166**	**(179,227)**	**362,682**	**(124,518)**	**395,014**	**174,005**	**253,722**	**(164,858)**	**158,382**	**(2,029)**	**(271,397)**	**(304,771)**	**368,171**

Regional Expansion Criteria and Benefits

Amounts in dollars

Line No.		Jan-19 Forecast	Feb-19 Forecast	Mar-19 Forecast	Apr-19 Forecast	May-19 Forecast	Jun-19 Forecast	Jul-19 Forecast	Aug-19 Forecast	Sep-19 Forecast	Oct-19 Forecast	Nov-19 Forecast	Dec-19 Forecast	2019 Forecast
	Revenue													
1	Schedule 26	6,292,976	6,037,132	5,651,903	5,377,147	6,216,611	7,331,538	8,265,686	8,089,825	7,162,741	5,500,146	5,831,270	6,211,674	77,968,650
2	Schedule 26(a)	7,839,792	7,063,437	6,751,424	6,351,043	6,703,403	7,792,826	8,560,507	8,741,795	7,365,493	6,826,804	6,643,912	6,256,957	86,897,395
3	Total Revenue	14,132,768	13,100,570	12,403,328	11,728,190	12,920,014	15,124,365	16,826,193	16,831,621	14,528,234	12,326,951	12,475,182	12,468,631	164,866,045
4														
5														
6	**Expense**													
7	Schedule 26	5,926,375	5,137,392	5,471,892	4,878,062	6,404,004	7,551,507	8,463,566	8,128,880	7,032,458	5,326,329	5,201,650	5,964,310	75,486,424
8	Schedule 26(a)	6,970,060	6,513,360	6,276,016	5,550,935	5,886,045	6,393,909	7,149,128	6,893,088	6,405,010	5,790,049	5,721,775	4,909,403	74,458,779
9	Total Expense	12,896,435	11,650,752	11,747,908	10,428,996	12,290,049	13,945,416	15,612,694	15,021,968	13,437,468	11,116,378	10,923,425	10,873,713	149,945,202
10														
11														
12	Total	(1,236,333)	(1,449,818)	(655,420)	(1,299,193)	(629,965)	(1,178,949)	(1,213,499)	(1,809,652)	(1,090,765)	(1,210,573)	(1,551,757)	(1,594,918)	(14,920,842)
13	Demand Allocator - State of MN Jur.	73.4404%	73.4404%	73.4404%	73.4404%	73.4404%	73.4404%	73.4404%	73.4404%	73.4404%	73.4404%	73.4404%	73.4404%	73.4404%
14	RECB Revenue Requirement	(907,968)	(1,064,752)	(481,343)	(954,133)	(462,649)	(865,825)	(891,199)	(1,329,017)	(801,063)	(889,050)	(1,139,617)	(1,171,314)	(10,957,930)
15	RECB in Base Rates	-	-	-	-	-	-	-	-	-	-	-	-	-
16	**Net RECB Revenue Requirements**	**(907,968)**	**(1,064,752)**	**(481,343)**	**(954,133)**	**(462,649)**	**(865,825)**	**(891,199)**	**(1,329,017)**	**(801,063)**	**(889,050)**	**(1,139,617)**	**(1,171,314)**	**(10,957,930)**

Amounts in dollars

NSPM Rider Rev Req by Rider Project	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Annual 2017	
ADMS														
CWIP Balance	5,050,173	5,489,242	5,877,795	6,255,409	6,505,967	8,753,714	9,174,808	13,503,052	14,784,842	15,789,256	16,368,175	16,543,904	16,543,904	
Plant In-Service														
Depreciation Reserve														
Accumulated Deferred Taxes	47,204	47,196	47,189	47,182	47,175	47,168	47,161	47,154	47,147	47,140	47,133	47,126	47,126	
Average Rate Base	5,111,898	5,222,508	5,636,325	6,019,416	6,333,509	7,582,668	8,917,096	11,291,773	14,096,796	15,239,905	16,031,579	16,408,910	16,408,910	
Tax Depreciation Expense														
CPI-TAX INTEREST												208	208	
Debt Return	9,627	9,836	10,615	11,337	11,928	14,281	16,794	21,266	26,549	28,702	30,193	30,903	222,031	
Equity Return	22,365	22,848	24,659	26,335	27,709	33,174	39,012	49,402	61,673	66,675	70,138	71,789	515,779	
Current Income Tax Requirement	15,776	16,117	17,395	18,577	19,547	23,403	27,523	34,853	43,513	47,041	49,485	50,797	364,026	
Book Depreciation														
AFUDC														
Deferred Taxes	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(85)	
Operating Expenses														
Property Tax Expense														
Total Revenue Requirement	47,761	48,794	52,662	56,242	59,177	70,851	83,322	105,514	131,728	142,411	149,809	153,482	1,101,751	
Rider Revenue Requirement	41,687	42,590	45,965	49,090	51,652	61,842	72,727	92,097	114,978	124,302	130,760	133,966	961,655	Line 1 Att 4
Big Stone-Brookings														
CWIP Balance	44,559,840	44,624,596	44,839,206	45,742,581	47,229,985	46,164,396	49,005,353	50,895,243	47,136,425	47,654,332	47,814,413	(0)	(0)	
Plant In-Service	3,519,601	3,519,538	3,519,538	3,519,538	3,519,538	3,519,538	3,519,538	3,519,538	7,881,012	7,881,012	7,881,012	65,037,531	65,037,531	
Depreciation Reserve									3,507	10,520	17,533	74,934	74,934	
Accumulated Deferred Taxes	1,039,629	2,138,837	3,238,044	4,337,252	5,436,460	6,535,668	7,634,876	8,734,084	9,833,292	10,932,500	12,031,708	13,130,916	13,130,916	
Average Rate Base	47,888,964	46,522,555	45,562,999	45,022,784	45,118,965	44,230,665	44,019,140	45,285,356	45,430,668	44,886,482	44,119,255	47,738,933	47,738,933	
Tax Depreciation Expense	2,775,647	2,775,647	2,775,647	2,775,647	2,775,647	2,775,647	2,775,647	2,775,647	2,775,647	2,775,647	2,775,647	2,775,647	33,307,767	
CPI-TAX INTEREST	16,179	15,056	19,335	20,826	21,531	19,920	149,743	156,778	151,521	144,293	145,644	79,670	940,498	
Debt Return	90,191	87,617	85,810	84,793	84,974	83,301	82,903	85,287	85,561	84,536	83,091	89,908	1,027,974	
Equity Return	209,514	203,536	199,338	196,975	197,395	193,509	192,584	198,123	198,759	196,378	193,022	208,858	2,387,992	
Current Income Tax Requirement	(1,023,663)	(1,028,673)	(1,028,616)	(1,029,232)	(1,028,437)	(1,032,317)	(941,365)	(932,492)	(933,278)	(937,585)	(938,999)	(938,823)	(11,793,482)	
Book Depreciation									3,507	7,013	7,013	57,401	74,934	
AFUDC														
Deferred Taxes	1,099,208	1,099,208	1,099,208	1,099,208	1,099,208	1,099,208	1,099,208	1,099,208	1,099,208	1,099,208	1,099,208	1,099,208	13,190,495	
Property Tax Expense	4,881	4,881	4,881	4,881	4,881	4,881	4,881	4,881	4,881	4,881	4,881	4,881	58,566	
Total Revenue Requirement	380,131	366,569	360,621	356,624	358,021	348,582	438,210	455,007	458,637	454,431	448,215	521,433	4,946,480	
Rider Revenue Requirement	279,720	269,741	265,365	262,425	263,452	256,507	322,461	334,821	337,489	334,391	329,816	383,693	3,639,881	Line 2 Att 4
CAPX2020 Brookings														
CWIP Balance	118,619	118,699	(2,473)	(3,833)	(4,845)	(4,450)	(7,032)	(7,032)	(7,032)	(7,032)	(7,032)	(7,032)	(7,032)	
Plant In-Service	453,785,411	452,454,754	453,139,051	453,540,328	453,464,933	453,527,016	453,745,849	455,218,891	455,279,367	455,268,222	455,288,666	455,305,522	455,305,522	
Depreciation Reserve	21,747,231	22,474,054	23,201,024	23,928,153	24,655,338	25,382,585	26,109,870	26,837,190	27,564,551	28,291,947	29,019,374	29,746,830	29,746,830	
Accumulated Deferred Taxes	87,846,447	88,287,558	88,728,669	89,169,780	89,610,891	90,052,002	90,493,113	90,934,224	91,375,335	91,816,446	92,257,557	92,698,668	92,698,668	
Average Rate Base	345,075,819	343,061,096	341,509,363	340,822,724	339,816,211	338,640,919	337,611,906	337,288,139	336,886,447	335,742,623	334,578,750	333,428,848	333,428,848	
Tax Depreciation Expense	1,802,555	1,802,555	1,802,555	1,802,555	1,802,555	1,802,555	1,802,555	1,802,555	1,802,555	1,802,555	1,802,555	1,802,555	21,630,656	
CPI-TAX INTEREST														
Debt Return	649,893	646,098	643,176	641,883	639,987	637,774	635,836	635,226	634,469	632,315	630,123	627,958	7,654,738	
Equity Return	1,509,707	1,500,892	1,494,103	1,491,099	1,486,696	1,481,554	1,477,052	1,475,636	1,473,878	1,468,874	1,463,782	1,458,751	17,782,025	
Current Income Tax Requirement	617,443	611,252	606,564	604,557	601,490	597,905	594,756	593,780	592,569	589,063	585,492	581,963	7,176,833	
Book Depreciation	726,784	726,824	726,969	727,129	727,185	727,247	727,286	727,320	727,361	727,396	727,426	727,456	8,726,383	
AFUDC														
Deferred Taxes	441,111	441,111	441,111	441,111	441,111	441,111	441,111	441,111	441,111	441,111	441,111	441,111	5,293,332	
Property Tax Expense	629,751	629,751	629,751	629,751	629,751	629,751	629,751	629,751	629,751	629,751	629,751	629,751	7,557,009	
Total Revenue Requirement	4,574,688	4,555,928	4,541,675	4,535,530	4,526,220	4,515,342	4,505,791	4,502,823	4,499,139	4,488,511	4,477,685	4,466,990	54,190,321	
Rider Revenue Requirement	3,366,327	3,352,523	3,342,034	3,337,513	3,330,662	3,322,657	3,315,629	3,313,445	3,310,734	3,302,913	3,294,947	3,287,077	39,876,460	Line 3 Att 4

Amounts in dollars

NSPM Rider Rev Req by Rider Project	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Annual 2017	
CAPX2020 - La Crosse Local														
CWIP Balance	(122,100)	(123,977)	(125,736)	(129,870)	(25,620)	(42,165)	(39,254)	(39,254)	(39,254)	(39,254)	(39,254)	(39,254)	(39,254)	
Plant In-Service	75,825,302	75,343,636	75,470,411	74,214,420	74,135,232	74,125,021	74,525,453	74,543,130	74,560,807	74,637,247	75,152,860	75,158,593	75,158,593	
Depreciation Reserve	1,206,364	1,337,110	1,467,542	1,596,967	1,725,266	1,853,539	1,982,152	2,111,133	2,240,146	2,369,242	2,498,859	2,628,936	2,628,936	
Accumulated Deferred Taxes	14,295,485	14,381,811	14,468,136	14,554,462	14,640,788	14,727,114	14,813,440	14,899,766	14,986,092	15,072,418	15,158,744	15,245,070	15,245,070	
Average Rate Base	60,353,404	59,851,046	59,454,868	58,671,058	57,838,339	57,622,881	57,596,405	57,591,792	57,394,146	57,225,824	57,306,168	57,350,668	57,350,668	
Tax Depreciation Expense	340,817	340,817	340,817	340,817	340,817	340,817	340,817	340,817	340,817	340,817	340,817	340,817	340,817	
CPI-TAX INTEREST														
Debt Return	113,666	112,719	111,973	110,497	108,929	108,523	108,473	108,465	108,092	107,775	107,927	108,010	1,315,050	
Equity Return	264,046	261,848	260,115	256,686	253,043	252,100	251,984	251,964	251,099	250,363	250,714	250,909	3,054,873	
Current Income Tax Requirement	99,276	97,448	96,003	92,873	89,507	88,824	88,982	89,228	88,640	88,179	88,795	89,257	1,097,010	
Book Depreciation	131,139	130,746	130,432	129,426	128,298	128,273	128,613	128,981	129,013	129,096	129,618	130,077	1,553,712	
AFUDC														
Deferred Taxes	86,326	86,326	86,326	86,326	86,326	86,326	86,326	86,326	86,326	86,326	86,326	86,326	1,035,911	
Property Tax Expense	105,093	105,093	105,093	105,093	105,093	105,093	105,093	105,093	105,093	105,093	105,093	105,093	1,261,118	
OATT Credit	192,030	190,883	189,869	187,706	185,265	184,673	184,766	184,902	184,471	184,128	184,522	184,809	2,238,023	
Total Revenue Requirement	607,516	603,298	600,072	593,195	585,931	584,467	584,706	585,155	583,792	582,704	583,951	584,863	7,079,650	
Rider Revenue Requirement	447,046	443,943	441,569	436,508	431,163	430,086	430,261	430,592	429,589	428,788	429,706	430,377	5,209,627	Line 4 Attt 4
CAPX2020 - La Crosse MISO														
CWIP Balance	658,704	637,728	639,357	635,512	638,469	638,470	0	0	0	0	0	0	0	
Plant In-Service	75,527,154	75,527,794	75,529,228	74,107,047	74,121,424	74,150,020	74,788,521	74,788,521	74,788,521	74,788,521	74,788,521	74,788,521	74,788,521	
Depreciation Reserve	2,617,020	2,737,975	2,858,928	2,978,616	3,097,038	3,215,460	3,333,882	3,452,304	3,570,726	3,689,149	3,807,571	3,925,993	3,925,993	
Accumulated Deferred Taxes	14,530,404	14,586,440	14,642,476	14,698,512	14,754,548	14,810,584	14,866,619	14,922,655	14,978,691	15,034,727	15,090,763	15,146,799	15,146,799	
Average Rate Base	59,126,398	58,939,770	58,754,144	57,866,306	56,986,870	56,835,377	56,675,232	56,500,790	56,326,332	56,151,874	55,977,416	55,802,958	55,802,958	
Tax Depreciation Expense	256,346	256,346	256,346	256,346	256,346	256,346	256,346	256,346	256,346	256,346	256,346	256,346	3,076,152	
CPI-TAX INTEREST														
Debt Return	111,355	111,003	110,654	108,982	107,325	107,040	106,738	106,410	106,081	105,753	105,424	105,096	1,291,860	
Equity Return	258,678	257,861	257,049	253,165	249,318	248,655	247,954	247,191	246,428	245,664	244,901	244,138	3,001,003	
Current Income Tax Requirement	126,532	125,955	125,382	121,748	118,140	117,673	117,178	116,640	116,101	115,563	115,024	114,485	1,430,421	
Book Depreciation	120,954	120,954	120,953	119,688	118,422	118,422	118,422	118,422	118,422	118,422	118,422	118,422	1,429,927	
AFUDC														
Deferred Taxes	56,036	56,036	56,036	56,036	56,036	56,036	56,036	56,036	56,036	56,036	56,036	56,036	672,430	
Property Tax Expense	104,729	104,729	104,729	104,729	104,729	104,729	104,729	104,729	104,729	104,729	104,729	104,729	1,256,750	
Total Revenue Requirement	778,284	776,539	774,803	764,347	753,970	752,555	751,058	749,428	747,797	746,167	744,537	742,906	9,082,391	
Rider Revenue Requirement	572,708	571,424	570,146	562,452	554,816	553,774	552,673	551,473	550,274	549,074	547,874	546,675	6,683,364	Line 5 Att 4
CAPX2020 - La Crosse MISO - WI														
CWIP Balance	0	0	0	0	0	0	0	0	0	0	0	0	0	
Plant In-Service	136,468,092	136,967,924	137,066,214	136,590,206	136,596,297	136,534,410	136,536,410	136,539,410	136,568,210	137,108,210	137,109,210	137,649,210	137,649,210	
Depreciation Reserve	3,704,114	3,926,875	4,150,161	4,373,109	4,595,639	4,818,109	5,040,517	5,262,929	5,485,354	5,708,268	5,931,657	6,155,523	6,155,523	
Accumulated Deferred Taxes	26,892,570	27,062,183	27,231,795	27,401,408	27,571,021	27,740,634	27,910,247	28,079,860	28,249,473	28,419,085	28,588,698	28,758,311	28,758,311	
Average Rate Base	105,928,660	105,925,137	105,831,562	105,249,974	104,622,663	104,202,652	103,780,656	103,391,134	103,015,002	102,907,120	102,784,856	102,662,115	102,662,115	
Tax Depreciation Expense	638,031	638,031	638,031	638,031	638,031	638,031	638,031	638,031	638,031	638,031	638,031	638,031	7,656,371	
CPI-TAX INTEREST														
Debt Return	199,499	199,492	199,316	198,221	197,039	196,248	195,454	194,720	194,012	193,808	193,578	193,347	2,354,735	
Equity Return	463,438	463,422	463,013	460,469	457,724	455,887	454,040	452,336	450,691	450,219	449,684	449,147	5,470,069	
Current Income Tax Requirement	153,177	153,658	153,739	151,706	149,474	148,135	146,789	145,588	144,437	144,449	144,407	144,364	1,779,923	
Book Depreciation	222,064	222,761	223,286	222,949	222,530	222,470	222,408	222,411	222,426	222,914	223,390	223,866	2,673,474	
AFUDC														
Deferred Taxes	169,613	169,613	169,613	169,613	169,613	169,613	169,613	169,613	169,613	169,613	169,613	169,613	2,035,354	
Property Tax Expense	188,851	188,851	188,851	188,851	188,851	188,851	188,851	188,851	188,851	188,851	188,851	188,851	2,266,217	
Total Revenue Requirement	1,396,643	1,397,798	1,397,819	1,391,808	1,385,231	1,381,205	1,377,156	1,373,520	1,370,029	1,369,853	1,369,523	1,369,188	16,579,772	
Rider Revenue Requirement	1,027,733	1,028,583	1,028,598	1,024,175	1,019,335	1,016,372	1,013,393	1,010,717	1,008,149	1,008,020	1,007,777	1,007,530	12,200,382	Line 6 Att 4

Amounts in dollars

NSPM Rider Rev Req by Rider Project	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Annual 2017	
CAPX2020 Fargo														
CWIP Balance	131,757	131,225	130,186	128,463	(6,746)	(7,551)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
Plant In-Service	207,169,874	207,174,575	207,240,816	207,267,417	207,420,110	207,422,489	207,422,176	207,422,176	207,422,176	207,422,176	207,422,176	207,422,176	207,422,176	
Depreciation Reserve	11,888,431	12,248,738	12,609,108	12,969,559	13,330,169	13,690,915	14,051,664	14,412,412	14,773,160	15,133,908	15,494,656	15,855,404	15,855,404	
Accumulated Deferred Taxes	40,604,595	40,842,377	41,080,160	41,317,942	41,555,725	41,793,507	42,031,290	42,269,072	42,506,855	42,744,637	42,982,420	43,220,202	43,220,202	
Average Rate Base	155,106,483	154,511,646	153,948,210	153,395,056	152,817,924	152,228,993	151,634,869	151,039,958	150,441,427	149,842,897	149,244,366	148,645,836	148,645,836	
Tax Depreciation Expense	942,489	942,489	942,489	942,489	942,489	942,489	942,489	942,489	942,489	942,489	942,489	942,489	11,309,863	
CPI-TAX INTEREST														
Debt Return	292,117	290,997	289,936	288,894	287,807	286,698	285,579	284,459	283,331	282,204	281,077	279,950	3,433,049	
Equity Return	678,591	675,988	673,523	671,103	668,578	666,002	663,403	660,800	658,181	655,563	652,944	650,326	7,975,002	
Current Income Tax Requirement	235,804	233,973	232,278	230,628	228,958	227,237	225,404	223,567	221,719	219,872	218,024	216,176	2,713,641	
Book Depreciation	360,299	360,307	360,370	360,452	360,610	360,746	360,748	360,748	360,748	360,748	360,748	360,748	4,327,272	
AFUDC														
Deferred Taxes	237,782	237,782	237,782	237,782	237,782	237,782	237,782	237,782	237,782	237,782	237,782	237,782	2,853,390	
Property Tax Expense	287,269	287,269	287,269	287,269	287,269	287,269	287,269	287,269	287,269	287,269	287,269	287,269	3,447,223	
Total Revenue Requirement	2,091,862	2,086,317	2,081,158	2,076,129	2,071,005	2,065,734	2,060,185	2,054,625	2,049,031	2,043,438	2,037,844	2,032,251	24,749,577	
Rider Revenue Requirement	1,539,316	1,535,236	1,531,440	1,527,739	1,523,968	1,520,090	1,516,006	1,511,915	1,507,799	1,503,683	1,499,567	1,495,451	18,212,210	Line 7 Att 4
LaCrosse - Madison														
CWIP Balance	44,275,301	48,601,038	47,029,255	49,829,583	55,123,875	59,852,050	64,812,197	70,485,447	78,371,574	85,124,897	90,271,765	94,751,004	94,751,004	
Plant In-Service			4,948,774	5,366,240	5,992,411	6,518,827	6,704,608	6,980,512	7,256,415	7,532,318	7,808,222	8,084,125	8,084,125	
Depreciation Reserve							(72)	(217)	(362)	(507)	(651)	(796)	(796)	
Accumulated Deferred Taxes	(482,992)	(560,467)	(637,942)	(715,417)	(792,892)	(870,367)	(947,842)	(1,025,317)	(1,102,792)	(1,180,268)	(1,257,743)	(1,335,218)	(1,335,218)	
Average Rate Base	42,089,839	46,959,898	50,888,738	54,263,606	58,910,209	64,575,211	69,852,982	75,478,106	82,611,318	90,284,566	96,588,185	101,754,762	101,754,762	
Tax Depreciation Expense	(3,174)	(3,174)	(3,174)	(3,174)	(3,174)	(3,174)	(3,174)	(3,174)	(3,174)	(3,174)	(3,174)	(3,174)	(38,093)	
CPI-TAX INTEREST	116,155	84,300	109,768	150,191	154,929	176,084	192,701	209,373	230,697	253,734	272,662	288,178	2,238,772	
Debt Return	79,269	88,441	95,840	102,196	110,948	121,617	131,556	142,150	155,585	170,036	181,908	191,638	1,571,185	
Equity Return	184,143	205,450	222,638	237,403	257,732	282,517	305,607	330,217	361,425	394,995	422,573	445,177	3,649,876	
Current Income Tax Requirement	159,466	152,023	182,122	221,063	238,751	271,166	299,133	328,211	365,278	405,221	438,036	464,934	3,525,407	
Book Depreciation							(72)	(145)	(145)	(145)	(145)	(145)	(796)	
AFUDC														
Deferred Taxes	(77,475)	(77,475)	(77,475)	(77,475)	(77,475)	(77,475)	(77,475)	(77,475)	(77,475)	(77,475)	(77,475)	(77,475)	(929,701)	
Property Tax Expense														
Total Revenue Requirement	345,404	368,439	423,126	483,188	529,956	597,824	658,749	722,959	804,668	892,632	964,897	1,024,130	7,815,971	
Rider Revenue Requirement	254,169	271,119	311,361	355,558	389,973	439,915	484,747	531,996	592,122	656,852	710,029	753,616	5,751,456	Line 8 Att 4
ADIT Pro-Rate														
Total Revenue Requirement							44,998	35,940	27,174	18,116	9,350	292	135,869	
Rider Revenue Requirement							33,112	26,447	19,996	13,331	6,880	215	99,981	Line 11 Att 4
MISO RECB Sch.26/26a														
Total Revenue Requirement	4,717,290	(272,148)	129,955	(587,077)	(415,374)	409,918	(190,138)	(406,764)	(859,676)	(380,303)	(1,034,734)	168,577	1,279,525	
Rider Revenue Requirement	3,471,262	(200,263)	95,629	(432,006)	(305,657)	301,642	(139,915)	(299,321)	(632,601)	(279,850)	(761,419)	124,049	941,551	Line 9 Att 4
RES Study														
Total Revenue Requirement	24,876	24,876	24,876	24,876	24,876	24,876	24,876	24,876	24,876	24,876	24,876	24,876	298,509	
Rider Revenue Requirement	24,876	24,876	24,876	24,876	24,876	24,876	24,876	24,876	24,876	24,876	24,876	24,876	298,509	Line 10 Att 4

Amounts in dollars

NSPM Rider Rev Req by Rider Project	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Annual 2018	
ADMS														
CWIP Balance	24,000,165	24,417,046	24,819,078	25,275,560	25,699,620	26,095,568	26,473,215	26,880,304	27,622,627	28,047,876	28,507,776	28,949,700	28,949,700	
Plant In-Service														
Depreciation Reserve														
Accumulated Deferred Taxes	46,670	46,214	45,758	45,303	44,847	44,391	43,935	43,479	43,024	42,568	42,112	41,656	41,656	
Average Rate Base	20,225,136	24,162,163	24,572,076	25,001,788	25,442,515	25,852,975	26,240,228	26,633,052	27,208,214	27,792,456	28,235,486	28,686,854	28,686,854	
Tax Depreciation Expense														
CPI-TAX INTEREST	472	573	667	819	1,007	1,146	1,242	1,302	1,356	1,431	1,585	1,790	13,390	
Debt Return	38,091	45,505	46,277	47,087	47,917	48,690	49,419	50,159	51,242	52,342	53,177	54,027	583,933	
Equity Return	88,485	105,709	107,503	109,383	111,311	113,107	114,801	116,520	119,036	121,592	123,530	125,505	1,356,482	
Current Income Tax Requirement	62,447	74,672	76,005	77,438	78,931	80,296	81,559	82,815	84,628	86,485	87,961	89,499	962,738	
Book Depreciation														
AFUDC														
Deferred Taxes	(456)	(456)	(456)	(456)	(456)	(456)	(456)	(456)	(456)	(456)	(456)	(456)	(5,469)	
Operating Expenses	12,375	12,375	12,375	12,375	12,375	12,375	12,375	12,375	12,375	12,375	12,375	12,375	148,504	
Property Tax Expense														
Total Revenue Requirement	200,942	237,807	241,704	245,827	250,079	254,012	257,699	261,413	266,826	272,339	276,588	280,950	3,046,187	
Rider Revenue Requirement	175,391	207,568	210,970	214,568	218,279	221,713	224,931	228,172	232,897	237,709	241,418	245,225	2,658,840	Line 1 Att 4
Big Stone-Brookings														
CWIP Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
Plant In-Service	64,858,618	64,691,004	64,501,732	64,501,732	64,501,732	64,501,732	64,501,732	64,501,732	64,501,732	64,501,732	64,501,732	64,501,732	64,501,732	
Depreciation Reserve	182,566	289,893	396,905	503,750	610,595	717,439	824,284	931,129	1,037,974	1,144,819	1,251,664	1,358,509	1,358,509	
Accumulated Deferred Taxes	13,192,785	13,254,653	13,316,522	13,378,391	13,440,260	13,502,129	13,563,998	13,625,866	13,687,735	13,749,604	13,811,473	13,873,342	13,873,342	
Average Rate Base	51,657,474	51,314,862	50,967,382	50,703,948	50,535,235	50,366,521	50,197,807	50,029,093	49,860,379	49,691,666	49,522,952	49,354,238	49,354,238	
Tax Depreciation Expense	257,919	257,919	257,919	257,919	257,919	257,919	257,919	257,919	257,919	257,919	257,919	257,919	3,095,026	
CPI-TAX INTEREST														
Debt Return	97,288	96,643	95,989	95,492	95,175	94,857	94,539	94,221	93,904	93,586	93,268	92,950	1,137,913	
Equity Return	226,001	224,503	222,982	221,830	221,092	220,354	219,615	218,877	218,139	217,401	216,663	215,925	2,643,382	
Current Income Tax Requirement	97,080	95,807	94,512	93,582	93,061	92,540	92,019	91,498	90,977	90,457	89,936	89,415	1,110,884	
Book Depreciation	107,632	107,326	107,012	106,845	106,845	106,845	106,845	106,845	106,845	106,845	106,845	106,845	1,283,575	
AFUDC														
Deferred Taxes	61,869	61,869	61,869	61,869	61,869	61,869	61,869	61,869	61,869	61,869	61,869	61,869	742,426	
Property Tax Expense	90,185	90,185	90,185	90,185	90,185	90,185	90,185	90,185	90,185	90,185	90,185	90,185	1,082,225	
Total Revenue Requirement	680,056	676,333	672,549	669,803	668,226	666,650	665,073	663,496	661,919	660,343	658,766	657,189	8,000,404	
Rider Revenue Requirement	499,433	496,699	493,920	491,903	490,745	489,588	488,430	487,272	486,114	484,956	483,799	482,641	5,875,499	Line 2 Att 4
CAPX2020 Brookings														
CWIP Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
Plant In-Service	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	
Depreciation Reserve	30,474,301	31,201,773	31,929,244	32,656,715	33,384,186	34,111,658	34,839,129	35,566,600	36,294,071	37,021,543	37,749,014	38,476,485	38,476,485	
Accumulated Deferred Taxes	93,078,787	93,458,906	93,839,024	94,219,143	94,599,262	94,979,381	95,359,500	95,739,619	96,119,737	96,499,856	96,879,975	97,260,094	97,260,094	
Average Rate Base	332,302,713	331,198,639	330,091,049	328,983,459	327,875,868	326,768,278	325,660,688	324,553,098	323,445,508	322,337,918	321,230,328	320,122,738	320,122,738	
Tax Depreciation Expense	1,653,508	1,653,508	1,653,508	1,653,508	1,653,508	1,653,508	1,653,508	1,653,508	1,653,508	1,653,508	1,653,508	1,653,508	19,842,096	
CPI-TAX INTEREST														
Debt Return	625,837	623,757	621,671	619,586	617,500	615,414	613,328	611,242	609,156	607,070	604,984	602,898	7,372,441	
Equity Return	1,453,824	1,448,994	1,444,148	1,439,303	1,434,457	1,429,611	1,424,766	1,419,920	1,415,074	1,410,228	1,405,383	1,400,537	17,126,245	
Current Income Tax Requirement	640,629	637,221	633,802	630,383	626,963	623,544	620,125	616,706	613,287	609,867	606,448	603,029	7,462,004	
Book Depreciation	727,471	727,471	727,471	727,471	727,471	727,471	727,471	727,471	727,471	727,471	727,471	727,471	8,729,655	
AFUDC														
Deferred Taxes	380,119	380,119	380,119	380,119	380,119	380,119	380,119	380,119	380,119	380,119	380,119	380,119	4,561,426	
Property Tax Expense	631,357	631,357	631,357	631,357	631,357	631,357	631,357	631,357	631,357	631,357	631,357	631,357	7,576,284	
Total Revenue Requirement	4,459,237	4,448,919	4,438,569	4,428,218	4,417,867	4,407,516	4,397,165	4,386,814	4,376,463	4,366,113	4,355,762	4,345,411	52,828,055	
Rider Revenue Requirement	3,274,883	3,267,305	3,259,704	3,252,102	3,244,500	3,236,899	3,229,297	3,221,695	3,214,093	3,206,492	3,198,890	3,191,288	38,797,148	Line 3 Att 4

Amounts in dollars

NSPM Rider Rev Req by Rider Project	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Annual 2018	
CAPX2020 - La Crosse Local														
CWIP Balance	(12,738)	(12,738)	(12,738)	(12,738)	(12,738)	(12,738)	(12,738)	(12,738)	(12,738)					
Plant In-Service	75,160,504	75,162,415	75,164,326	75,166,237	75,168,148	76,257,418	76,258,374	76,259,329	76,260,285	76,260,285	76,260,285	76,260,285	76,260,285	
Depreciation Reserve	2,759,020	2,889,107	3,019,198	3,149,292	3,279,389	3,410,449	3,542,469	3,674,491	3,806,515	3,938,540	4,070,565	4,202,589	4,202,589	
Accumulated Deferred Taxes	15,342,580	15,440,090	15,537,600	15,635,110	15,732,620	15,830,130	15,927,640	16,025,151	16,122,661	16,220,171	16,317,681	16,415,191	16,415,191	
Average Rate Base	57,145,750	56,933,323	56,707,635	56,481,943	56,256,249	56,573,751	56,889,813	56,661,238	56,432,660	56,209,972	55,986,807	55,757,272	55,757,272	
Tax Depreciation Expense	369,859	369,859	369,859	369,859	369,859	369,859	369,859	369,859	369,859	369,859	369,859	369,859	369,859	
CPI-TAX INTEREST														
Debt Return	107,624	107,224	106,799	106,374	105,949	106,547	107,142	106,712	106,282	105,862	105,442	105,010	1,276,969	
Equity Return	250,013	249,083	248,096	247,109	246,121	247,510	248,893	247,893	246,893	245,919	244,942	243,938	2,966,409	
Current Income Tax Requirement	76,028	75,374	74,680	73,986	73,291	74,950	76,604	75,900	75,195	74,508	73,820	73,111	897,448	
Book Depreciation	130,084	130,087	130,091	130,094	130,097	131,059	132,020	132,022	132,024	132,025	132,025	132,025	1,573,653	
AFUDC														
Deferred Taxes	97,510	97,510	97,510	97,510	97,510	97,510	97,510	97,510	97,510	97,510	97,510	97,510	1,170,121	
Property Tax Expense	104,220	104,220	104,220	104,220	104,220	104,220	104,220	104,220	104,220	104,220	104,220	104,220	1,250,639	
OATT Credit	173,819	173,341	172,864	172,386	171,909	172,955	173,998	173,513	173,029	172,543	172,057	171,570	2,073,984	
Total Revenue Requirement	591,660	590,158	588,532	586,906	585,280	588,842	592,392	590,743	589,094	587,500	585,902	584,244	7,061,255	
Rider Revenue Requirement	434,518	433,415	432,220	431,026	429,832	432,448	435,056	433,845	432,633	431,463	430,289	429,071	5,185,816	Line 4 Attt 4
CAPX2020 - La Crosse MISO														
CWIP Balance	0	0	0	0	0	0	0	0	0	0	0	0	0	
Plant In-Service	74,788,521	74,788,521	74,788,521	74,788,521	74,788,521	74,788,521	74,788,521	74,788,521	74,788,521	74,788,521	74,788,521	74,788,521	74,788,521	
Depreciation Reserve	4,044,415	4,162,837	4,281,259	4,399,682	4,518,104	4,636,526	4,754,948	4,873,370	4,991,792	5,110,215	5,228,637	5,347,059	5,347,059	
Accumulated Deferred Taxes	15,214,793	15,282,787	15,350,781	15,418,775	15,486,769	15,554,763	15,622,757	15,690,751	15,758,745	15,826,739	15,894,733	15,962,727	15,962,727	
Average Rate Base	55,622,521	55,436,105	55,249,689	55,063,272	54,876,856	54,690,440	54,504,024	54,317,608	54,131,192	53,944,776	53,758,359	53,571,943	53,571,943	
Tax Depreciation Expense	284,883	284,883	284,883	284,883	284,883	284,883	284,883	284,883	284,883	284,883	284,883	284,883	3,418,598	
CPI-TAX INTEREST														
Debt Return	104,756	104,405	104,054	103,702	103,351	103,000	102,649	102,298	101,947	101,596	101,245	100,894	1,233,897	
Equity Return	243,349	242,533	241,717	240,902	240,086	239,271	238,455	237,640	236,824	236,008	235,193	234,377	2,866,355	
Current Income Tax Requirement	102,230	101,655	101,079	100,504	99,928	99,353	98,777	98,202	97,626	97,051	96,475	95,900	1,188,779	
Book Depreciation	118,422	118,422	118,422	118,422	118,422	118,422	118,422	118,422	118,422	118,422	118,422	118,422	1,421,066	
AFUDC														
Deferred Taxes	67,994	67,994	67,994	67,994	67,994	67,994	67,994	67,994	67,994	67,994	67,994	67,994	815,928	
Property Tax Expense	103,707	103,707	103,707	103,707	103,707	103,707	103,707	103,707	103,707	103,707	103,707	103,707	1,244,481	
Total Revenue Requirement	740,457	738,715	736,973	735,231	733,489	731,747	730,004	728,262	726,520	724,778	723,036	721,294	8,770,506	
Rider Revenue Requirement	543,795	542,516	541,236	539,957	538,677	537,398	536,118	534,839	533,560	532,280	531,001	529,721	6,441,097	Line 5 Att 4
CAPX2020 - La Crosse MISO - WI														
CWIP Balance	0	0	0	0	0	0	0	0	0	0	0	0	0	
Plant In-Service	137,649,210	137,649,210	137,649,210	137,649,210	137,649,210	137,649,210	137,649,210	137,649,210	137,649,210	137,649,210	137,649,210	137,649,210	137,649,210	
Depreciation Reserve	6,379,865	6,604,206	6,828,547	7,052,889	7,277,230	7,501,571	7,725,913	7,950,254	8,174,595	8,398,936	8,623,278	8,847,619	8,847,619	
Accumulated Deferred Taxes	28,884,677	29,011,043	29,137,408	29,263,774	29,390,140	29,516,506	29,642,872	29,769,237	29,895,603	30,021,969	30,148,335	30,274,700	30,274,700	
Average Rate Base	102,560,022	102,209,315	101,858,608	101,507,901	101,157,194	100,806,487	100,455,779	100,105,072	99,754,365	99,403,658	99,052,951	98,702,244	98,702,244	
Tax Depreciation Expense	533,706	533,706	533,706	533,706	533,706	533,706	533,706	533,706	533,706	533,706	533,706	533,706	6,404,478	
CPI-TAX INTEREST														
Debt Return	193,155	192,494	191,834	191,173	190,513	189,852	189,192	188,531	187,871	187,210	186,550	185,889	2,274,264	
Equity Return	448,700	447,166	445,631	444,097	442,563	441,028	439,494	437,960	436,425	434,891	433,357	431,822	5,283,134	
Current Income Tax Requirement	187,481	186,399	185,316	184,234	183,151	182,068	180,986	179,903	178,820	177,738	176,655	175,572	2,178,323	
Book Depreciation	224,341	224,341	224,341	224,341	224,341	224,341	224,341	224,341	224,341	224,341	224,341	224,341	2,692,096	
AFUDC														
Deferred Taxes	126,366	126,366	126,366	126,366	126,366	126,366	126,366	126,366	126,366	126,366	126,366	126,366	1,516,389	
Property Tax Expense	190,874	190,874	190,874	190,874	190,874	190,874	190,874	190,874	190,874	190,874	190,874	190,874	2,290,483	
Total Revenue Requirement	1,370,917	1,367,639	1,364,362	1,361,084	1,357,807	1,354,529	1,351,252	1,347,974	1,344,697	1,341,419	1,338,142	1,334,865	16,234,688	
Rider Revenue Requirement	1,006,807	1,004,400	1,001,993	999,586	997,179	994,772	992,365	989,958	987,551	985,144	982,737	980,330	11,922,824	Line 6 Att 4

Amounts in dollars

NSPM Rider Rev Req by Rider Project	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Annual 2018	
CAPX2020 Fargo														
CWIP Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
Plant In-Service	207,422,176	207,422,176	207,422,176	207,422,176	207,422,176	207,422,176	207,422,176	207,422,176	207,422,176	207,422,176	207,422,176	207,422,176	207,422,176	
Depreciation Reserve	16,216,152	16,576,900	16,937,648	17,298,395	17,659,143	18,019,891	18,380,639	18,741,387	19,102,135	19,462,883	19,823,631	20,184,379	20,184,379	
Accumulated Deferred Taxes	43,431,295	43,642,388	43,853,481	44,064,574	44,275,667	44,486,760	44,697,853	44,908,946	45,120,039	45,331,133	45,542,226	45,753,319	45,753,319	
Average Rate Base	148,060,650	147,488,809	146,916,968	146,345,127	145,773,286	145,201,445	144,629,604	144,057,763	143,485,922	142,914,081	142,342,240	141,770,399	141,770,399	
Tax Depreciation Expense	877,290	877,290	877,290	877,290	877,290	877,290	877,290	877,290	877,290	877,290	877,290	877,290	10,527,482	
CPI-TAX INTEREST														
Debt Return	278,848	277,771	276,694	275,617	274,540	273,463	272,386	271,309	270,232	269,155	268,078	267,001	3,275,091	
Equity Return	647,765	645,264	642,762	640,260	637,758	635,256	632,755	630,253	627,751	625,249	622,747	620,245	7,608,065	
Current Income Tax Requirement	241,542	239,777	238,012	236,246	234,481	232,716	230,950	229,185	227,420	225,654	223,889	222,124	2,781,997	
Book Depreciation	360,748	360,748	360,748	360,748	360,748	360,748	360,748	360,748	360,748	360,748	360,748	360,748	4,328,976	
AFUDC														
Deferred Taxes	211,093	211,093	211,093	211,093	211,093	211,093	211,093	211,093	211,093	211,093	211,093	211,093	2,533,116	
Property Tax Expense	287,625	287,625	287,625	287,625	287,625	287,625	287,625	287,625	287,625	287,625	287,625	287,625	3,451,505	
Total Revenue Requirement	2,027,622	2,022,277	2,016,933	2,011,589	2,006,245	2,000,901	1,995,557	1,990,213	1,984,869	1,979,525	1,974,181	1,968,837	23,978,750	
Rider Revenue Requirement	1,489,094	1,485,169	1,481,244	1,477,320	1,473,395	1,469,470	1,465,546	1,461,621	1,457,696	1,453,772	1,449,847	1,445,922	17,610,096	Line 7 Att 4
LaCrosse - Madison														
CWIP Balance	101,722,790	106,971,921	112,023,118	116,171,273	120,521,694	126,581,398	132,178,751	136,767,881	140,573,463	143,957,187	146,367,245	(636)	(636)	
Plant In-Service	8,185,823	8,287,521	8,389,219	8,490,917	8,592,616	8,694,314	8,796,012	8,897,710	8,999,408	9,101,106	9,202,805	157,950,611	157,950,611	
Depreciation Reserve	(941)	(1,086)	(1,230)	(1,375)	(1,520)	(1,664)	(1,809)	(1,954)	(2,099)	(2,243)	(2,388)	127,843	127,843	
Accumulated Deferred Taxes	623,053	2,581,324	4,539,595	6,497,866	8,456,137	10,414,408	12,372,679	14,330,950	16,289,221	18,247,492	20,205,763	22,164,034	22,164,034	
Average Rate Base	106,728,822	110,982,852	114,276,588	117,019,836	119,412,696	122,761,330	126,733,431	129,970,244	132,311,172	134,049,397	135,089,860	135,512,386	135,512,386	
Tax Depreciation Expense	5,236,075	5,236,075	5,236,075	5,236,075	5,236,075	5,236,075	5,236,075	5,236,075	5,236,075	5,236,075	5,236,075	5,236,075	62,832,903	
CPI-TAX INTEREST	350,709	373,264	392,545	409,972	426,237	445,895	467,797	487,210	503,563	517,869	529,789	269,911	5,174,762	
Debt Return	201,006	209,018	215,221	220,387	224,894	231,201	238,681	244,777	249,186	252,460	254,419	255,215	2,796,465	
Equity Return	466,939	485,550	499,960	511,962	522,431	537,081	554,459	568,620	578,861	586,466	591,018	592,867	6,496,213	
Current Income Tax Requirement	(1,736,017)	(1,706,969)	(1,683,196)	(1,662,431)	(1,643,568)	(1,619,360)	(1,591,643)	(1,567,953)	(1,549,187)	(1,533,727)	(1,522,104)	(1,612,178)	(19,428,332)	
Book Depreciation	(145)	(145)	(145)	(145)	(145)	(145)	(145)	(145)	(145)	(145)	(145)	130,231	128,639	
AFUDC														
Deferred Taxes	1,958,271	1,958,271	1,958,271	1,958,271	1,958,271	1,958,271	1,958,271	1,958,271	1,958,271	1,958,271	1,958,271	1,958,271	23,499,252	
Property Tax Expense	11,210	11,210	11,210	11,210	11,210	11,210	11,210	11,210	11,210	11,210	11,210	11,210	134,520	
Total Revenue Requirement	901,264	956,935	1,001,321	1,039,254	1,073,093	1,118,258	1,170,834	1,214,781	1,248,196	1,274,535	1,292,670	1,335,616	13,626,756	
Rider Revenue Requirement	661,892	702,777	735,374	763,233	788,084	821,253	859,865	892,140	916,681	936,024	949,342	980,882	10,007,548	Line 8 Att 4
ADIT Pro-Rate														
Total Revenue Requirement	141,179	129,379	116,314	103,672	90,607	77,964	64,900	51,836	39,193	26,129	13,486	421	855,080	
Rider Revenue Requirement	103,682	95,016	85,422	76,137	66,542	57,257	47,663	38,068	28,783	19,189	9,904	309	627,974	Line 11 Att 4
MISO RECB Sch.26/26a														
Total Revenue Requirement	96,902	(244,043)	493,845	(169,550)	537,870	236,933	345,480	(224,479)	215,660	(2,763)	(369,547)	(414,991)	501,319	
Rider Revenue Requirement	71,166	(179,227)	362,682	(124,518)	395,014	174,005	253,722	(164,858)	158,382	(2,029)	(271,397)	(304,771)	368,171	Line 9 Att 4
RES Study														
Total Revenue Requirement														
Rider Revenue Requirement														Line 10 Att 4

Amounts in dollars

NSPM Rider Rev Req by Rider Project	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Annual 2019	
ADMS														
CWIP Balance	30,039,516	31,163,982	32,236,473	33,499,539	34,658,655	35,800,446	36,855,612	37,910,778	38,948,619	40,055,760	41,284,176	42,512,592	42,512,592	
Plant In-Service														
Depreciation Reserve														
Accumulated Deferred Taxes	39,793	37,929	36,065	34,202	32,338	30,474	28,611	26,747	24,883	23,019	21,156	19,292	19,292	
Average Rate Base	29,453,884	30,562,888	31,663,231	32,832,873	34,045,827	35,198,145	36,298,487	37,355,517	38,403,884	39,478,238	40,647,881	41,878,160	41,878,160	
Tax Depreciation Expense														
CPI-TAX INTEREST	2,165	2,542	2,894	3,458	4,156	4,671	5,029	5,256	5,458	5,739	6,312	7,072	54,751	
Debt Return	55,226	57,305	59,369	61,562	63,836	65,997	68,060	70,042	72,007	74,022	76,215	78,522	802,161	
Equity Return	128,861	133,713	138,527	143,644	148,950	153,992	158,806	163,430	168,017	172,717	177,834	183,217	1,871,708	
Current Income Tax Requirement	91,138	94,828	98,473	102,482	106,719	110,640	114,289	117,712	121,091	124,606	128,621	132,955	1,343,552	
Book Depreciation														
AFUDC														
Deferred Taxes	(1,864)	(1,864)	(1,864)	(1,864)	(1,864)	(1,864)	(1,864)	(1,864)	(1,864)	(1,864)	(1,864)	(1,864)	(22,364)	
Operating Expenses	25,877	25,877	25,877	25,877	25,877	25,877	25,877	25,877	25,877	25,877	25,877	25,877	310,523	
Property Tax Expense														
Total Revenue Requirement	299,238	309,859	320,381	331,700	343,518	354,641	365,168	375,198	385,128	395,358	406,683	418,706	4,305,579	
Rider Revenue Requirement	261,188	270,458	279,642	289,522	299,837	309,546	318,734	327,488	336,156	345,085	354,970	365,465	3,758,091	Line 1 Att 4
Big Stone-Brookings														
CWIP Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
Plant In-Service	64,501,732	64,501,732	64,501,732	64,501,732	64,501,732	64,501,732	64,501,732	64,501,732	64,501,732	64,501,732	64,501,732	64,501,732	64,501,732	
Depreciation Reserve	1,465,354	1,572,199	1,679,044	1,785,889	1,892,734	1,999,579	2,106,424	2,213,269	2,320,114	2,426,959	2,533,804	2,640,649	2,640,649	
Accumulated Deferred Taxes	13,933,035	13,992,729	14,052,422	14,112,116	14,171,810	14,231,503	14,291,197	14,350,890	14,410,584	14,470,277	14,529,971	14,589,664	14,589,664	
Average Rate Base	49,186,612	49,020,073	48,853,535	48,686,996	48,520,458	48,353,919	48,187,381	48,020,842	47,854,304	47,687,765	47,521,227	47,354,688	47,354,688	
Tax Depreciation Expense	252,474	252,474	252,474	252,474	252,474	252,474	252,474	252,474	252,474	252,474	252,474	252,474	3,029,685	
CPI-TAX INTEREST														
Debt Return	92,225	91,913	91,600	91,288	90,976	90,664	90,351	90,039	89,727	89,415	89,102	88,790	1,086,090	
Equity Return	215,191	214,463	213,734	213,006	212,277	211,548	210,820	210,091	209,363	208,634	207,905	207,177	2,534,209	
Current Income Tax Requirement	91,205	90,691	90,176	89,662	89,148	88,634	88,120	87,606	87,092	86,578	86,064	85,549	1,060,524	
Book Depreciation	106,845	106,845	106,845	106,845	106,845	106,845	106,845	106,845	106,845	106,845	106,845	106,845	1,282,140	
AFUDC														
Deferred Taxes	59,694	59,694	59,694	59,694	59,694	59,694	59,694	59,694	59,694	59,694	59,694	59,694	716,323	
Property Tax Expense	89,442	89,442	89,442	89,442	89,442	89,442	89,442	89,442	89,442	89,442	89,442	89,442	1,073,309	
Total Revenue Requirement	654,602	653,047	651,492	649,937	648,382	646,827	645,272	643,717	642,162	640,607	639,052	637,497	7,752,594	
Rider Revenue Requirement	480,741	479,599	478,457	477,315	476,173	475,031	473,889	472,747	471,605	470,463	469,322	468,180	5,693,521	Line 2 Att 4
CAPX2020 Brookings														
CWIP Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
Plant In-Service	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	
Depreciation Reserve	39,203,957	39,931,428	40,658,899	41,386,370	42,113,842	42,841,313	43,568,784	44,296,256	45,023,727	45,751,198	46,478,669	47,206,141	47,206,141	
Accumulated Deferred Taxes	97,586,268	97,912,442	98,238,616	98,564,790	98,890,964	99,217,138	99,543,312	99,869,486	100,195,660	100,521,834	100,848,008	101,174,182	101,174,182	
Average Rate Base	319,042,120	317,988,475	316,934,829	315,881,184	314,827,539	313,773,893	312,720,248	311,666,603	310,612,957	309,559,312	308,505,667	307,452,021	307,452,021	
Tax Depreciation Expense	1,521,442	1,521,442	1,521,442	1,521,442	1,521,442	1,521,442	1,521,442	1,521,442	1,521,442	1,521,442	1,521,442	1,521,442	18,257,303	
CPI-TAX INTEREST														
Debt Return	598,204	596,228	594,253	592,277	590,302	588,326	586,350	584,375	582,399	580,424	578,448	576,473	7,048,059	
Equity Return	1,395,809	1,391,200	1,386,590	1,381,980	1,377,370	1,372,761	1,368,151	1,363,541	1,358,932	1,354,322	1,349,712	1,345,103	16,445,471	
Current Income Tax Requirement	654,816	651,564	648,311	645,058	641,806	638,553	635,300	632,048	628,795	625,543	622,290	619,037	7,643,122	
Book Depreciation	727,471	727,471	727,471	727,471	727,471	727,471	727,471	727,471	727,471	727,471	727,471	727,471	8,729,655	
AFUDC														
Deferred Taxes	326,174	326,174	326,174	326,174	326,174	326,174	326,174	326,174	326,174	326,174	326,174	326,174	3,914,088	
Property Tax Expense	631,357	631,357	631,357	631,357	631,357	631,357	631,357	631,357	631,357	631,357	631,357	631,357	7,576,284	
Total Revenue Requirement	4,333,832	4,323,994	4,314,156	4,304,318	4,294,480	4,284,642	4,274,804	4,264,966	4,255,128	4,245,291	4,235,453	4,225,615	51,356,680	
Rider Revenue Requirement	3,182,785	3,175,560	3,168,335	3,161,110	3,153,885	3,146,660	3,139,435	3,132,210	3,124,984	3,117,759	3,110,534	3,103,309	37,716,564	Line 3 Att 4

Amounts in dollars

NSPM Rider Rev Req by Rider Project	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Annual 2019	
CAPX2020 - La Crosse Local														
CWIP Balance														
Plant In-Service	76,260,285	76,260,285	76,260,285	76,260,285	76,260,285	76,260,285	76,260,285	76,260,285	76,260,285	76,260,285	76,260,285	76,260,285	76,260,285	
Depreciation Reserve	4,334,614	4,466,639	4,598,663	4,730,688	4,862,713	4,994,737	5,126,762	5,258,787	5,390,811	5,522,836	5,654,861	5,786,885	5,786,885	
Accumulated Deferred Taxes	16,489,347	16,563,503	16,637,659	16,711,815	16,785,971	16,860,128	16,934,284	17,008,440	17,082,596	17,156,752	17,230,908	17,305,064	17,305,064	
Average Rate Base	55,539,414	55,333,233	55,127,053	54,920,872	54,714,691	54,508,510	54,302,329	54,096,149	53,889,968	53,683,787	53,477,606	53,271,426	53,271,426	
Tax Depreciation Expense	313,572	313,572	313,572	313,572	313,572	313,572	313,572	313,572	313,572	313,572	313,572	313,572	313,572	
CPI-TAX INTEREST														
Debt Return	104,136	103,750	103,363	102,977	102,590	102,203	101,817	101,430	101,044	100,657	100,271	99,884	1,224,122	
Equity Return	242,985	242,083	241,181	240,279	239,377	238,475	237,573	236,671	235,769	234,867	233,965	233,062	2,856,285	
Current Income Tax Requirement	95,677	95,040	94,404	93,767	93,131	92,494	91,858	91,221	90,585	89,948	89,312	88,675	1,106,113	
Book Depreciation	132,025	132,025	132,025	132,025	132,025	132,025	132,025	132,025	132,025	132,025	132,025	132,025	1,584,296	
AFUDC														
Deferred Taxes	74,156	74,156	74,156	74,156	74,156	74,156	74,156	74,156	74,156	74,156	74,156	74,156	889,873	
Property Tax Expense	105,748	105,748	105,748	105,748	105,748	105,748	105,748	105,748	105,748	105,748	105,748	105,748	1,268,971	
OATT Credit	171,323	170,886	170,449	170,012	169,575	169,138	168,701	168,264	167,827	167,390	166,953	166,516	2,027,033	
Total Revenue Requirement	583,404	581,915	580,427	578,939	577,451	575,963	574,475	572,987	571,499	570,011	568,522	567,034	6,902,627	
Rider Revenue Requirement	428,454	427,361	426,268	425,175	424,083	422,990	421,897	420,804	419,711	418,618	417,525	416,432	5,069,319	Line 4 Attt 4
CAPX2020 - La Crosse MISO														
CWIP Balance	0	0	0	0	0	0	0	0	0	0	0	0	0	
Plant In-Service	74,788,521	74,788,521	74,788,521	74,788,521	74,788,521	74,788,521	74,788,521	74,788,521	74,788,521	74,788,521	74,788,521	74,788,521	74,788,521	
Depreciation Reserve	5,465,481	5,583,903	5,702,325	5,820,748	5,939,170	6,057,592	6,176,014	6,294,436	6,412,858	6,531,280	6,649,703	6,768,125	6,768,125	
Accumulated Deferred Taxes	16,021,988	16,081,249	16,140,511	16,199,772	16,259,034	16,318,295	16,377,556	16,436,818	16,496,079	16,555,341	16,614,602	16,673,863	16,673,863	
Average Rate Base	53,389,893	53,212,210	53,034,526	52,856,843	52,679,159	52,501,476	52,323,792	52,146,108	51,968,425	51,790,741	51,613,058	51,435,374	51,435,374	
Tax Depreciation Expense	263,504	263,504	263,504	263,504	263,504	263,504	263,504	263,504	263,504	263,504	263,504	263,504	3,162,051	
CPI-TAX INTEREST														
Debt Return	100,106	99,773	99,440	99,107	98,773	98,440	98,107	97,774	97,441	97,108	96,774	96,441	1,179,284	
Equity Return	233,581	232,803	232,026	231,249	230,471	229,694	228,917	228,139	227,362	226,584	225,807	225,030	2,751,663	
Current Income Tax Requirement	104,261	103,713	103,164	102,616	102,067	101,519	100,970	100,422	99,873	99,325	98,776	98,228	1,214,932	
Book Depreciation	118,422	118,422	118,422	118,422	118,422	118,422	118,422	118,422	118,422	118,422	118,422	118,422	1,421,066	
AFUDC														
Deferred Taxes	59,261	59,261	59,261	59,261	59,261	59,261	59,261	59,261	59,261	59,261	59,261	59,261	711,137	
Property Tax Expense	103,707	103,707	103,707	103,707	103,707	103,707	103,707	103,707	103,707	103,707	103,707	103,707	1,244,481	
Total Revenue Requirement	719,338	717,679	716,020	714,361	712,702	711,043	709,384	707,725	706,066	704,407	702,748	701,089	8,522,563	
Rider Revenue Requirement	528,285	527,067	525,848	524,630	523,412	522,193	520,975	519,756	518,538	517,319	516,101	514,883	6,259,007	Line 5 Att 4
CAPX2020 - La Crosse MISO - WI														
CWIP Balance	0	0	0	0	0	0	0	0	0	0	0	0	0	
Plant In-Service	137,649,210	137,649,210	137,649,210	137,649,210	137,649,210	137,649,210	137,649,210	137,649,210	137,649,210	137,649,210	137,649,210	137,649,210	137,649,210	
Depreciation Reserve	9,071,960	9,296,302	9,520,643	9,744,984	9,969,326	10,193,667	10,418,008	10,642,350	10,866,691	11,091,032	11,315,373	11,539,715	11,539,715	
Accumulated Deferred Taxes	30,384,651	30,494,602	30,604,553	30,714,504	30,824,455	30,934,406	31,044,357	31,154,308	31,264,259	31,374,210	31,484,161	31,594,112	31,594,112	
Average Rate Base	98,359,744	98,025,452	97,691,160	97,356,867	97,022,575	96,688,283	96,353,991	96,019,698	95,685,406	95,351,114	95,016,822	94,682,529	94,682,529	
Tax Depreciation Expense	493,520	493,520	493,520	493,520	493,520	493,520	493,520	493,520	493,520	493,520	493,520	493,520	5,922,243	
CPI-TAX INTEREST														
Debt Return	184,425	183,798	183,171	182,544	181,917	181,291	180,664	180,037	179,410	178,783	178,157	177,530	2,171,726	
Equity Return	430,324	428,861	427,399	425,936	424,474	423,011	421,549	420,086	418,624	417,161	415,699	414,236	5,067,360	
Current Income Tax Requirement	191,288	190,256	189,224	188,192	187,160	186,129	185,097	184,065	183,033	182,001	180,969	179,937	2,227,350	
Book Depreciation	224,341	224,341	224,341	224,341	224,341	224,341	224,341	224,341	224,341	224,341	224,341	224,341	2,692,096	
AFUDC														
Deferred Taxes	109,951	109,951	109,951	109,951	109,951	109,951	109,951	109,951	109,951	109,951	109,951	109,951	1,319,412	
Property Tax Expense	190,874	190,874	190,874	190,874	190,874	190,874	190,874	190,874	190,874	190,874	190,874	190,874	2,290,483	
Total Revenue Requirement	1,331,203	1,328,081	1,324,960	1,321,839	1,318,717	1,315,596	1,312,475	1,309,354	1,306,232	1,303,111	1,299,990	1,296,868	15,768,426	
Rider Revenue Requirement	977,641	975,349	973,056	970,764	968,472	966,179	963,887	961,595	959,303	957,010	954,718	952,426	11,580,399	Line 6 Att 4

Amounts in dollars

NSPM Rider Rev Req by Rider Project	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Annual 2019	
CAPX2020 Fargo														
CWIP Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
Plant In-Service	207,422,176	207,422,176	207,422,176	207,422,176	207,422,176	207,422,176	207,422,176	207,422,176	207,422,176	207,422,176	207,422,176	207,422,176	207,422,176	
Depreciation Reserve	20,545,127	20,905,875	21,266,623	21,627,371	21,988,119	22,348,867	22,709,615	23,070,363	23,431,111	23,791,859	24,152,607	24,513,355	24,513,355	
Accumulated Deferred Taxes	45,943,217	46,133,116	46,323,014	46,512,913	46,702,811	46,892,710	47,082,608	47,272,507	47,462,405	47,652,304	47,842,202	48,032,101	48,032,101	
Average Rate Base	141,209,155	140,658,509	140,107,862	139,557,216	139,006,569	138,455,923	137,905,276	137,354,630	136,803,983	136,253,337	135,702,690	135,152,044	135,152,044	
Tax Depreciation Expense	825,402	825,402	825,402	825,402	825,402	825,402	825,402	825,402	825,402	825,402	825,402	825,402	9,904,828	
CPI-TAX INTEREST														
Debt Return	264,767	263,735	262,702	261,670	260,637	259,605	258,572	257,540	256,507	255,475	254,443	253,410	3,109,063	
Equity Return	617,790	615,381	612,972	610,563	608,154	605,745	603,336	600,927	598,517	596,108	593,699	591,290	7,254,481	
Current Income Tax Requirement	242,049	240,349	238,649	236,949	235,249	233,549	231,850	230,150	228,450	226,750	225,050	223,350	2,792,395	
Book Depreciation	360,748	360,748	360,748	360,748	360,748	360,748	360,748	360,748	360,748	360,748	360,748	360,748	4,328,976	
AFUDC														
Deferred Taxes	189,898	189,898	189,898	189,898	189,898	189,898	189,898	189,898	189,898	189,898	189,898	189,898	2,278,782	
Property Tax Expense	287,625	287,625	287,625	287,625	287,625	287,625	287,625	287,625	287,625	287,625	287,625	287,625	3,451,505	
Total Revenue Requirement	1,962,878	1,957,737	1,952,595	1,947,454	1,942,312	1,937,171	1,932,029	1,926,888	1,921,747	1,916,605	1,911,464	1,906,322	23,215,202	
Rider Revenue Requirement	1,441,546	1,437,770	1,433,994	1,430,218	1,426,442	1,422,667	1,418,891	1,415,115	1,411,339	1,407,563	1,403,787	1,400,011	17,049,344	Line 7 Att 4
LaCrosse - Madison														
CWIP Balance														
Plant In-Service	158,890,753	159,401,504	159,738,050	159,947,096	160,348,239	161,097,792	161,882,186	162,631,739	163,224,037	163,607,288	163,711,811	163,816,334	163,816,334	
Depreciation Reserve	389,277	651,986	915,437	1,179,368	1,443,837	1,709,320	1,976,156	2,244,344	2,513,715	2,783,946	3,054,607	3,325,452	3,325,452	
Accumulated Deferred Taxes	22,462,316	22,760,598	23,058,880	23,357,162	23,655,444	23,953,726	24,252,008	24,550,289	24,848,571	25,146,853	25,445,135	25,743,417	25,743,417	
Average Rate Base	135,848,629	136,014,041	135,876,327	135,587,149	135,329,762	135,341,852	135,544,384	135,745,564	135,849,428	135,769,120	135,444,279	134,979,767	134,979,767	
Tax Depreciation Expense	995,288	995,288	995,288	995,288	995,288	995,288	995,288	995,288	995,288	995,288	995,288	995,288	11,943,451	
CPI-TAX INTEREST														
Debt Return	254,716	255,026	254,768	254,226	253,743	253,766	254,146	254,523	254,718	254,567	253,958	253,087	3,051,244	
Equity Return	594,338	595,061	594,459	593,194	592,068	592,121	593,007	593,887	594,341	593,990	592,569	590,536	7,119,570	
Current Income Tax Requirement	112,027	113,437	113,536	112,982	112,567	113,320	114,899	116,475	117,630	117,989	117,290	115,986	1,378,137	
Book Depreciation	261,434	262,708	263,452	263,931	264,469	265,483	266,836	268,188	269,371	270,231	270,661	270,845	3,197,609	
AFUDC														
Deferred Taxes	298,282	298,282	298,282	298,282	298,282	298,282	298,282	298,282	298,282	298,282	298,282	298,282	3,579,383	
Property Tax Expense	219,025	219,025	219,025	219,025	219,025	219,025	219,025	219,025	219,025	219,025	219,025	219,025	2,628,298	
Total Revenue Requirement	1,739,822	1,743,540	1,743,522	1,741,639	1,740,154	1,741,997	1,746,194	1,750,379	1,753,367	1,754,084	1,751,784	1,747,761	20,954,242	
Rider Revenue Requirement	1,277,732	1,280,463	1,280,450	1,279,067	1,277,976	1,279,330	1,282,412	1,285,486	1,287,680	1,288,207	1,286,518	1,283,563	15,388,885	Line 8 Att 4
ADIT Pro-Rate														
Total Revenue Requirement	54,184	49,655	44,641	39,789	34,775	29,922	24,908	19,894	15,042	10,028	5,176	162	328,176	
Rider Revenue Requirement	39,793	36,467	32,784	29,221	25,539	21,975	18,293	14,610	11,047	7,365	3,801	119	241,014	Line 11 Att 4
MISO RECB Sch.26/26a														
Total Revenue Requirement	(1,236,333)	(1,449,818)	(655,420)	(1,299,194)	(629,965)	(1,178,949)	(1,213,499)	(1,809,652)	(1,090,765)	(1,210,573)	(1,551,757)	(1,594,918)	-14,920,842	
Rider Revenue Requirement	(907,968)	(1,064,752)	(481,343)	(954,133)	(462,649)	(865,825)	(891,199)	(1,329,017)	(801,063)	(889,050)	(1,139,617)	(1,171,314)	-10,957,930	Line 9 Att 4
RES Study														
Total Revenue Requirement														
Rider Revenue Requirement														Line 10 Att 4

Revenue Requirement Model Logic

Revenue Requirement Calculation
Amounts in dollars

	CAPX2020 Brookings	Dec 2017	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total 2018 Sum of Jan through Dec 2018
A	Plant In-Service (CAA Input)	455,298,490	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	455,305,522	
B	Depreciation Reserve (CAA Input)	29,746,830	30,474,301	31,201,773	31,929,244	32,656,715	33,384,186	34,111,658	34,839,129	35,566,600	36,294,071	37,021,543	37,749,014	38,476,485	
C	Accumulated Deferred Taxes (CAA Input)	92,698,668	93,078,787	93,458,906	93,839,024	94,219,143	94,599,262	94,979,381	95,359,500	95,739,619	96,119,737	96,499,856	96,879,975	97,260,094	
D	(PIS - Reserve - ADIT)	332,852,992	331,752,434	330,644,844	329,537,254	328,429,663	327,322,073	326,214,483	325,106,893	323,999,303	322,891,713	321,784,123	320,676,533	319,568,943	
E	**Average Rate Base (Prior Mo + Cur Month)/2**		**332,302,713**	**331,198,639**	**330,091,049**	**328,983,459**	**327,875,868**	**326,768,278**	**325,660,688**	**324,553,098**	**323,445,508**	**322,337,918**	**321,230,328**	**320,122,738**	
F	Tax Depreciation Expense (CAA Input)		1,653,508	1,653,508	1,653,508	1,653,508	1,653,508	1,653,508	1,653,508	1,653,508	1,653,508	1,653,508	1,653,508	1,653,508	
G	Debt Return (Ave RB * Wtd Cost of Debt)		625,837	623,757	621,671	619,586	617,500	615,414	613,328	611,242	609,156	607,070	604,984	602,898	
H	Equity Return (Ave RB * Wtd Cost of Equity)		1,453,824	1,448,994	1,444,148	1,439,303	1,434,457	1,429,611	1,424,766	1,419,920	1,415,074	1,410,228	1,405,383	1,400,537	
I	Current Income Tax Requirement (See Below)		640,629	637,221	633,802	630,383	626,963	623,544	620,125	616,706	613,287	609,867	606,448	603,029	
J	Book Depreciation (CAA Input)		727,471	727,471	727,471	727,471	727,471	727,471	727,471	727,471	727,471	727,471	727,471	727,471	
K	Deferred Taxes (CAA Input)		380,119	380,119	380,119	380,119	380,119	380,119	380,119	380,119	380,119	380,119	380,119	380,119	
L	Property Taxes (A * Prop Tax Factor)		631,357	631,357	631,357	631,357	631,357	631,357	631,357	631,357	631,357	631,357	631,357	631,357	
M	Total Revenue Requirement (G+H+I+J+K+L)		4,459,237	4,448,919	4,438,569	4,428,218	4,417,867	4,407,516	4,397,165	4,386,814	4,376,463	4,366,113	4,355,762	4,345,411	
N	Jurisdiction Revenue Requirement (M * ND Jur)		3,274,883	3,267,305	3,259,704	3,252,102	3,244,500	3,236,899	3,229,297	3,221,695	3,214,093	3,206,492	3,198,890	3,191,288	
O	**Rider Revenue Requirement (N)**		**3,274,883**	**3,267,305**	**3,259,704**	**3,252,102**	**3,244,500**	**3,236,899**	**3,229,297**	**3,221,695**	**3,214,093**	**3,206,492**	**3,198,890**	**3,191,288**	**38,797,148**

Reconciliation to Attachment 4	
Line 3 of Annual Tracker Summary	38,797,148
Difference	-

Capital Structure	2018 Weighted Cost
Long Term Debt	2.2100%
Short Term Debt	0.0500%
Preferred Stock	0.0000%
Common Equity	5.2500%
Required Rate of Return	7.5100%
Tax Rate (MN)	41.3700%
MN Jurisdictional Factor	73.44043%

	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Equity Return (Item H)	1,453,824	1,448,994	1,444,148	1,439,303	1,434,457	1,429,611	1,424,766	1,419,920	1,415,074	1,410,228	1,405,383	1,400,537
Book Depreciation (Item J)	727,471	727,471	727,471	727,471	727,471	727,471	727,471	727,471	727,471	727,471	727,471	727,471
Deferred Taxes (Item K)	380,119	380,119	380,119	380,119	380,119	380,119	380,119	380,119	380,119	380,119	380,119	380,119
Less Tax Depreciation (Item F)	(1,653,508)	(1,653,508)	(1,653,508)	(1,653,508)	(1,653,508)	(1,653,508)	(1,653,508)	(1,653,508)	(1,653,508)	(1,653,508)	(1,653,508)	(1,653,508)
Plus CPI-Tax Interest (If Applicable)	0	0	0	0	0	0	0	0	0	0	0	0
Sum	907,906	903,076	898,230	893,385	888,539	883,693	878,848	874,002	869,156	864,310	859,465	854,619
Tax Rate (T/(1-T)	70.56%	70.56%	70.56%	70.56%	70.56%	70.56%	70.56%	70.56%	70.56%	70.56%	70.56%	70.56%
Tax Calc (Sum * Tax Rate)	640,629	637,221	633,802	630,383	626,963	623,544	620,125	616,706	613,287	609,867	606,448	603,029

REPORT:

COST OF EQUITY – TCR RIDER

PREPARED FOR

NORTHERN STATES POWER COMPANY - MINNESOTA

BEFORE THE:

MINNESOTA PUBLIC UTILITIES COMMISSION

NOVEMBER 8, 2017

www.ceadvisors.com

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I. INTRODUCTION AND QUALIFICATIONS

My name is James M. Coyne. My business address is 293 Boston Post Road West, Suite 500, Marlborough, MA 01752.

I am employed by Concentric Energy Advisors, Inc. ("Concentric") as a Senior Vice President. Concentric is a management consulting and economic advisory firm, focused on the North American energy and water industries. Based in Marlborough, Massachusetts and Washington D.C., Concentric specializes in regulatory and litigation support, financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses.

I provide expert testimony before federal, state and Canadian provincial agencies on matters pertaining to economics, finance, and public policy in the energy industry. I regularly advise utilities, generating companies, public bodies and private equity investors on business issues pertaining to the utility industry. This work includes calculating the cost of capital for the purpose of ratemaking and providing expert testimony and studies on matters pertaining to rate policy, valuation, capital costs, alternative regulation, fuels and power markets. I have authored numerous articles on the energy industry, lectured on utility regulation for regulatory commission staff, and provided testimony before the FERC as well as state and provincial jurisdictions in the U.S. and Canada. I have also testified before the Minnesota Public Utilities Commission ("Commission"). I hold a B.S. in Business Administration from Georgetown University and a M.S. in Resource Economics from the University of New Hampshire. My educational and professional background is summarized more fully in Appendix 1.

I am submitting this report on behalf of Northern States Power Company, a Minnesota corporation ("NSPM" or the "Company"), a wholly-owned subsidiary of Xcel Energy Inc. ("Xcel Energy").

II. PURPOSE AND OVERVIEW

The purpose of this report is to present evidence and provide a recommendation regarding an appropriate return on equity ("ROE")[1] for NSPM's Transmission Cost Recovery ("TCR") rider. Appendix 2 contains a description of the various models used to estimate the cost of equity and the assumptions underlying those models. My analyses and conclusions are supported by the data presented in Appendix 3, Schedules 1 through 5.2.

My ROE recommendation is based primarily on the range of results that I derive from the Discounted Cash Flow ("DCF") model, the Bond Yield Plus Risk Premium approach ("Risk Premium") and the Capital Asset Pricing Model ("CAPM"). In addition, I consider authorized returns in other jurisdictions for electric utility companies in 2016 and 2017, the most recent FERC authorized ROE for MISO transmission owners, and the Commission's prior precedents for setting TCR rider ROEs.

My recommendation takes into consideration the general economic and capital market environment. I specifically consider the unusually low Treasury bond yields in the current market which, when combined with the unsustainable high valuations and low dividend yields of utility stocks, are causing the DCF model to under-estimate the cost of equity at this time. For that reason, I also give weight to the results of the Risk Premium approach and the CAPM analysis, both of which can be adjusted to reflect investor expectations for higher interest rates by using forward-looking data. This is especially important given the shift that has occurred in monetary policy as the Federal Reserve continues to move toward normalizing interest rates after an extended period of policy accommodation.

The ROE results presented in my Schedules indicate a wide range of results from 8.19 percent to 10.78 percent from a combination of models and alternative input assumptions. Based on the results of all three methods (i.e., DCF, Risk Premium, and CAPM), and taking into consideration my observations pertaining to capital market conditions, and authorized returns in other

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1 I use the terms "ROE" and "cost of equity" interchangeably throughout my Direct Testimony.
2 In the remainder of this report, all references to "Schedules" are to the schedules contained in Appendix 3.

jurisdictions, I recommend the Commission authorize an ROE of 10.0 percent for the TCR rider.

The balance of this report is organized as follows: Section III provides background on the regulatory principles behind making an ROE determination in general. Section IV presents a review of current and projected capital market conditions and the implications for the utility cost of capital. Section V describes the criteria and approach for selecting a proxy group of comparable companies. Section VI discusses the market data and models used to estimate the cost of equity, as well as the results of the Constant Growth DCF, Risk Premium and CAPM analyses. Section VII summarizes my results, conclusions and recommendation.

III. REGULATORY PRINCIPLES

Utilities are entitled by law to receive a fair rate of return sufficient to attract needed capital at reasonable rates. The basic tenets of this regulatory doctrine originate from several bellwether decisions by the United States Supreme Court, and that doctrine is followed to the same degree across this country with respect to state-level rate-making, including in Minnesota.

Regulated utilities rely primarily on common stock and long-term debt to finance their permanent property, plant and equipment. The allowed rate of return for a regulated utility is based on its weighted average cost of capital, where the costs of the individual sources of capital, debt and equity, are weighted by their respective book values. The ROE represents the cost of raising and retaining equity capital, and is estimated through one or more analytical techniques that use market data to quantify investor expectations regarding equity returns.

However, the ROE cannot be derived solely through quantitative metrics and models. To properly estimate the ROE the financial, regulatory and economic context in which the analysis takes place must also be considered. The DCF, Risk Premium and CAPM approaches, while fundamental to the ROE determination, are still only models. One should not assume that the results of these models can be mechanistically applied without also considering informed judgment and the context of capital market conditions.

Also, it is important to note that the U.S. Supreme Court has held that under the statutory standard of "just and reasonable" it is the result reached, not the method employed, which is controlling.[3] Consequently, it is appropriate to consider a variety of approaches and data sources when arriving at a recommended ROE.

The ratemaking process is premised on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility services, the utility must have the opportunity to recover the return of invested capital, and the market-required return on that capital. Because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital on favorable terms. Such decisions balance the long-term interests of customers and shareholders. The financial community carefully monitors the current and expected financial condition of utility companies, as well as the regulatory environment in which they operate. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' assessments of risk. It is therefore important for the ROE authorized in this proceeding to take into consideration current and expected capital market conditions, as well as investors' expectations and requirements regarding both risks and returns.

Concentric recognizes that the Commission's determination of the appropriate rate of return for the TCR rider looks to the ROE allowed in the Company's last general rate case, unless the Commission determines that a different rate of return is in the public interest.[4] In this instance, NSPM's last general electric rate case was decided in May 2017, when the Company's ROE was set at 9.20 percent as part of a negotiated settlement.[5] In its decision approving the settlement, the Commission stated "the Settlement does not prevent any party from contesting the ROE when it is applied in rider dockets or other proceedings" and that "parties will be free to assert an alternative ROE at that time."[6] On that basis, Concentric presents an updated cost of equity analysis in support of its recommendation.

[3] Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944), at 602.
[4] Minn. Statute 216B.16, subd.7b.
[5] E-002/GR-15-0826, May 11, 2017.
[6] *Ibid,* at 22.

IV. CAPITAL MARKET CONDITIONS AND IMPLICATIONS FOR ROE

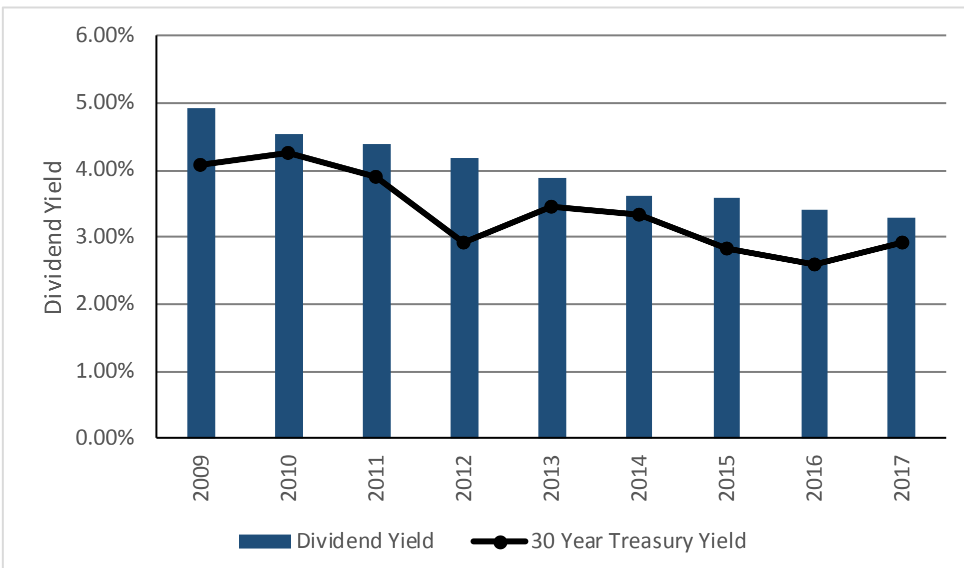
The required cost of capital, including the ROE, is a function of prevailing and expected conditions in the general economy and in financial markets. The standard ROE estimation tools, such as the DCF, CAPM and Risk Premium models, each reflect the state of the general economy and financial markets by incorporating specific economic and financial data. These inputs are, however, only samples of the various economic and market forces that may affect the ROE going forward. Consideration must be given to whether the assumptions relied on in the current or projected data are sustainable over the period that the recommended ROE will be in effect. If investors do not expect current market conditions to be sustained in the future, it is possible that the ROE estimation models will not provide an accurate estimate of investors' required return. Therefore, an assessment of fluctuating market conditions is integral to any ROE recommendation.

In the current capital market environment, the cost of equity for regulated utility companies is being affected by two factors requiring special consideration: (a) low government bond yields, which have led to high valuations and low dividend yields on utility stocks relative to historical levels; and (b) the change in monetary policy and the market's expectation for higher interest rates. In this section, I discuss each of these factors and how it affects the models used to estimate the cost of equity for regulated utilities.

The Federal Open Market Committee ("FOMC") took extraordinary measures (both reductions in short-term interest rates and purchases of Treasury bonds and mortgage-backed securities) over the past decade to stimulate the U.S. economy. The resulting very low or zero returns on short-term government bonds drove yield-seeking investors into longer-term instruments, bidding up prices and reducing yields on those investments. Furthermore, the Federal Reserve's purchases of longer-term bonds drove Treasury bond yields to historic lows, with the 10-year government bond yield reaching a low of 1.36 percent in July 2016. Continued economic expansion and "normalization" of Federal Reserve policy have relieved some of this downward pressure on the 10-year Treasury yield, which has since rebounded to 2.33 percent as of September 29, 2017.

The Federal Reserve's accommodative monetary policy caused investors to seek alternatives to the historically low interest rates available on Treasury bonds. As a result of this search for higher yield, the share prices for many common stocks, especially dividend-paying stocks such as utilities, have been driven higher while the dividend yields (which are computed by dividing the dividend payment by the stock price) have decreased to levels well below the historical average. As shown in Figure 1, since the Federal Reserve intervened to stabilize financial markets and support the economic recovery after the Great Recession of 2008-09, Treasury bond yields and utility dividend yields have both declined. Specifically, 30-year Treasury bond yields have fallen by approximately 115 basis points since 2009, and electric utility dividend yields have decreased by about 163 basis points over this same period.

Figure 1: Dividend Yields for Electric Utility Stocks



Similarly, Xcel Energy's average dividend yield has declined from 5.15 percent in 2009 to an average of 3.17 percent in 2017.

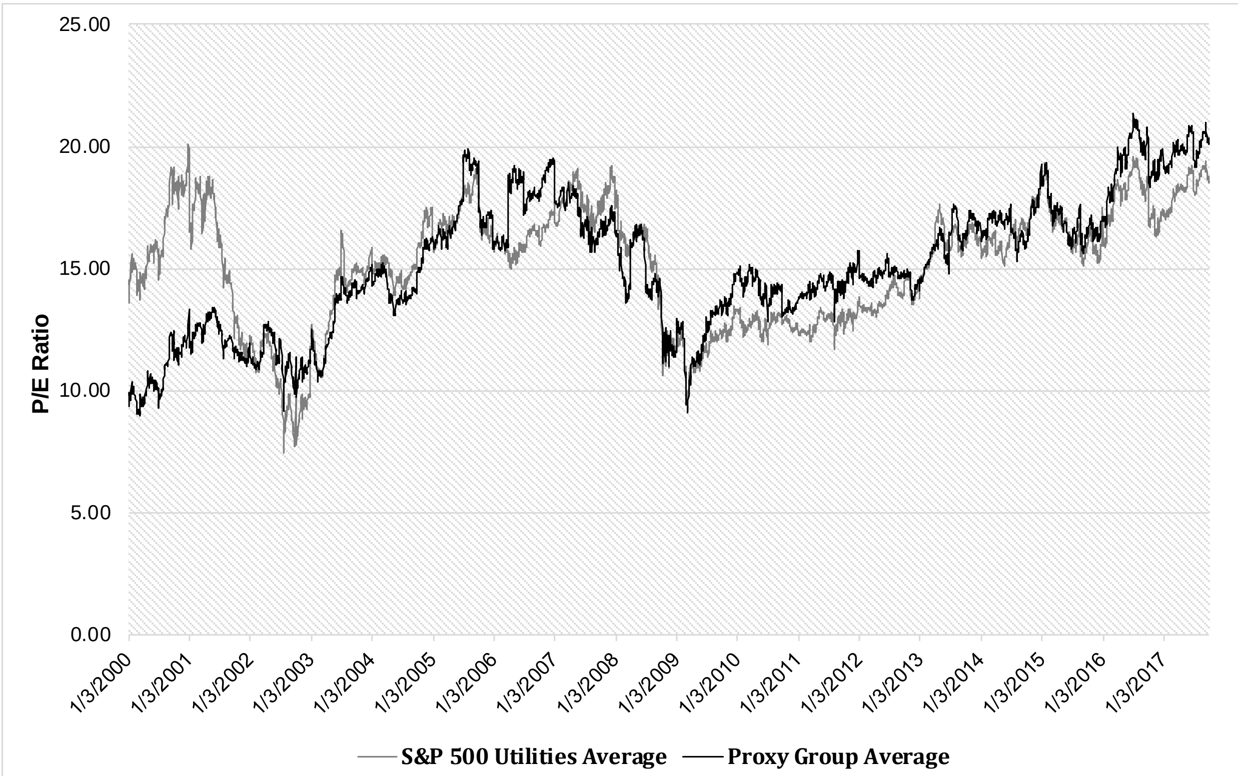
The DCF model is generally a reliable model to estimate the cost of equity and adequately reflects market conditions and investor expectations. However, in the current market environment, the DCF model results are distorted by the historically low level of interest rates and the higher valuation of utility stocks. Value Line recently commented on the industry's low dividend yields and high valuations:

> The high valuation of stocks in the Electric Utility Industry is evident by a few ways of measuring this. The group's average dividend yield, at 3.3%, is comfortably above the median of all stocks under our coverage. However, this yield is low, by historical standards. In addition, for many years electric utility equities had a price-earnings ratio well below that of the market. Thus, the relative price-earnings ratio shown on our pages was below 1.00. Last year, this figure was right around 1.00 for many electric utility stocks. Today, many issues have a price-earnings ratio above 20. We also note that the majority of electric utility equities are trading within their 3- to 5-year Target Price Range. A few, such as ALLETE and CMS Energy, have recent prices above their 2020-2022 Target Price Range. As a result, the long-term total return potential of this group is just 3%, despite the likelihood of annual dividend growth from most of these companies. Income-oriented investors should keep this in mind.[7]

As shown in Figure 2, the average price/earnings ("P/E") ratio for the proxy companies and utilities in general has been steadily climbing since the end of the financial crisis in 2009, and today is near the highest level since 2000. These high current valuations are important because the DCF model utilizes current dividend yields based on unsustainable stock prices. Value Line projects that P/E ratios for the proxy group companies will contract in the next few years. All else equal, if the P/E ratios for electric utility stocks decline consistent with Value Line's projections, the DCF model will produce higher ROE estimates. Therefore, the DCF model is likely understating the forward-looking cost of equity for the proxy group companies under these circumstances.

[7] Value Line Investment Survey, Electric Utility (Central) Industry, June 16, 2017, at 901.

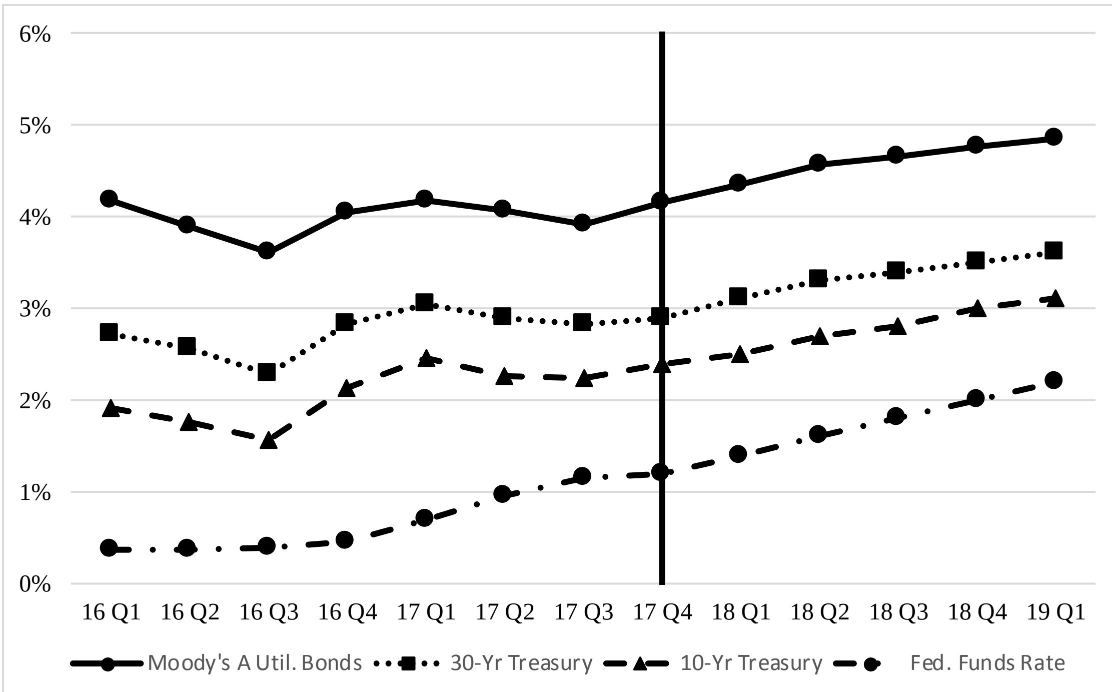
Figure 2: Utility P/E Ratios vs. Proxy Group 2000 to September 2017



Since the process of estimating the cost of equity is a forward-looking analysis, it is not appropriate to base the ROE estimate on the low interest rate environment of the past few years, especially when interest rates are increasing and are expected to be significantly higher in the next several years. As shown in

Figure 3, the interest rate environment is changing, as the Federal Reserve has begun tightening monetary policy, raising the federal funds rate in 25 basis point increments four times since December 2015. Yields on 10-year and 30-year Treasury bonds have increased substantially from the low point in July 2016. In addition, investor expectations are for higher interest rates on Treasury bonds and utility bonds over the next few years.[8]

Figure 3: Interest Rate Conditions[9]



The Federal Reserve has announced its intention to raise short-term interest rates in 25 basis point increments once more in 2017 and three times in 2018.[10]

According to the October 2017 issue of Blue Chip Financial Forecasts, almost 96 percent of those surveyed expect the Federal Reserve will raise short-term interest rates again at the December 2017 meeting.[11] In response to the question regarding expected increases in interest rates in 2018 by the Federal Reserve, 29 percent of those surveyed expect an increase of 50 basis points, 38 percent expect an increase of 75 basis points, and 24 percent expect an increase of

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8 These investor expectations are reported by Blue Chip Financial Forecasts, which conducts a monthly survey of 45 economists employed by some of America's largest and most respected manufacturers, banks, insurance companies and brokerage firms in order to develop their consensus view.

9 Source: Historical data from Bloomberg Professional. Forecast data from Blue Chip Financial Forecasts, Volume 36, No. 10, October 1, 2017, at 2.

10 FOMC, Federal Reserve press release, December 14, 2016.

11 Blue Chip Financial Forecasts, Vol. 36, Issue No. 10, October 1, 2017, at 14.

100 basis points.[12] These responses are aligned with the FOMC target rate projections noted above.

Furthermore, in Janet Yellen's testimony to Congress in July 2017, the Chair discussed the Fed's intention to begin reducing the size of its balance sheet. In response to the Great Recession, the Fed pursued a policy known as "Quantitative Easing," in which it systematically purchased mortgage-backed securities and long-term Treasury bonds to provide liquidity in financial markets and drive down yields on long-term government bonds. Although the Federal Reserve discontinued the Quantitative Easing program in October 2014, it has continued to reinvest the proceeds from the bonds it holds. The FOMC announced that it plans to start reducing the size of the Fed's $4.5 trillion bond portfolio in October 2017 by no longer reinvesting the proceeds of the bonds it holds.[13] The announced unwinding plan provides additional support for investors' view that long-term interest rates will increase, as the Federal Reserve gradually reverses the Quantitative Easing program that reduced those long-term rates.

NSPM's most recent authorized ROE for its electric utility operations was 9.20 percent, which was approved by the Commission in May 2017 as part of a negotiated settlement agreement. The settlement negotiations between the parties occurred in July and August 2016. At that time, interest rates on 10-year Treasury bonds in the third quarter of 2016 averaged 1.56 percent, as compared with 2.24 percent in the third quarter of 2017. This suggests that capital costs have increased for electric utilities since that time, which supports an ROE for the TCR rider greater than the ROE that was approved in the previous electric rate case.

It is necessary to consider the effects of capital market conditions on the inputs and assumptions used in the ROE estimation models and to consider whether current market conditions are sustainable on a forward-looking basis. The Federal Reserve's accommodative monetary policy in recent years has resulted in high utility valuations and low dividend yields. As the Federal Reserve continues to normalize monetary policy, these high valuations and low dividend yields for utility stocks are not sustainable. Therefore, it is not appropriate to rely solely on the results

12 *Ibid.*

13 Federal Reserve press release, Addendum to the Policy Normalization Principles and Plans, June 14, 2017, implemented at FOMC meeting September 20, 2017.

of the DCF model because that model is based on historical stock prices, which are used to calculate the dividend yield. Rather, I also give weight to the Risk Premium model and the CAPM, both of which can be adjusted to use a forward-looking risk-free rate that is consistent with market expectations for higher Treasury yields. Specifically, I have used a forecasted 30-year Treasury bond yield in both the CAPM and Risk Premium analyses in order to take into consideration the market's expectation for higher interest rates. As the DCF model relies on "unrepresentative" inputs in the current market environment, I place less weight on these results.

V. PROXY GROUP SELECTION

Since the ROE is a market-based concept and given the fact that NSPM is not publicly-traded, it is necessary to establish a group of companies that is both publicly-traded and comparable to certain NSPM business and financial characteristics to serve as a "proxy" for purposes of the ROE estimation process. Even if NSPM's regulated utility operations in Minnesota made up the entirety of a publicly-traded entity, it is possible that transitory events could bias the Company's market value in one way or another over a given period of time. A significant benefit of using a proxy group is the ability to mitigate the effects of company-specific events that may not be representative of the industry or long-term trends. As a result of the screening criteria used to select my proxy group, the companies in my ROE analyses have similar business and operating characteristics to NSPM's regulated electric utility operations, and thus provide a reasonable basis for the derivation and assessment of ROE estimates.

NSPM, a wholly-owned subsidiary of Xcel Energy, Inc. ("Xcel"), provides electric and natural gas service to approximately 1.27 million electric customers and 452,000 gas customers in Minnesota.[14] In addition, I note that NSPM's regulated electric utility operations accounted for approximately 90 percent of operating revenue, with the remaining 10 percent coming from the

[14] Northern States Power – Minnesota FERC Form 1, December 31, 2016, at 304; Gas Jurisdictional Annual Report, Northern States Power – Minnesota, 2016.

regulated gas distribution business.[15] NSPM's long-term issuer ratings are A- from Standard & Poor's ("S&P") and A2 from Moody's Investor Services ("Moody's").[16]

To develop the proxy group, I began with the 40 domestic companies that Value Line classifies as "Electric Utilities" and then screened companies according to the following criteria:

1) Consistently pays quarterly cash dividends;
2) Maintains an investment grade long-term issuer rating (BBB- or higher) from S&P;
3) Is covered by more than one equity analyst;
4) Has positive earnings growth rates published by at least two of the following sources: Value Line Investment Survey ("Value Line"), Thomson First Call (as reported by Yahoo! Finance), and Zacks Investment Research ("Zacks");
5) Owns generation assets that are included in rate base;
6) Owned generation comprises greater than 25 percent of the Company's MWh sales to ultimate customers
7) Regulated revenue and net operating income makes up more than 60 percent of the consolidated company's net operating income;
8) Regulated electric revenue and net operating income makes up more than 80 percent of the consolidated company's regulated operations; and
9) Is not involved in a merger or other transformative transaction for an approximate six-month period prior to my analysis.

These are the same screening criteria that I used to develop my ROE recommendation in NSPM's most recent electric rate case.

I did not include Xcel Energy in my proxy group because it is my general practice to exclude the subject company, or its parent holding company, from the proxy group due to the circular logic that would occur by including those results.

Based on these screening criteria, I developed a proxy group consisting of the electric utility companies shown in Figure 4.

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15 Northern States Power – Minnesota FERC Form 1, December 31, 2016, at 115.
16 Source: SNL Financial.

Figure 4: Electric Utility Proxy Group

Company	**Ticker**
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Duke Energy Corporation	DUK
El Paso Electric Company	EE
Hawaiian Electric Industries, Inc.	HEI
IDACORP, Inc.	IDA
OGE Energy Corp.	OGE
Pinnacle West Capital Corporation	PNW
PNM Resources, Inc.	PNM
Portland General Electric Company	POR
PPL Corporation	PPL
Southern Company	SO

Please refer to Schedule 1 for my proxy group screening data and results.

I have selected the above proxy group to best align with the financial and operational characteristics of NSPM's electric utility operations. The screening criterion requiring an investment grade credit rating ensures that the proxy companies, like NSPM, are generally in sound financial condition. Additionally, I have screened on the percent of revenue and net operating income from regulated operations to differentiate utilities that derive the large majority of their revenue and income from regulated operations from those with substantial merchant or market-related risks. Also, I have screened on the percent contribution of the electric utility segment to overall financial results in order to differentiate utilities that, like NSPM, derive the predominant share of their revenue and operating income from their electric segment. Further, the generation screen identifies utilities that, like NSPM, own regulated generation in rate base and bear the risk of generation in their asset mix. These screens collectively reflect the risk factors that investors consider in making their investment decisions in electric utility companies.

VI. DETERMINATION OF THE APPROPRIATE COST OF EQUITY

I have considered the results of several ROE estimation models, including the Constant Growth DCF, Risk Premium, and CAPM models. The formulas used to derive the results of each model and the assumptions underlying each approach are described in detail in Appendix 2.

All of the traditional ROE estimation methods are being distorted toward unreasonably low ROE estimates by current market conditions. As discussed previously, economic conditions are causing the results of the DCF model to be unreliable. As prices for utility stocks have increased, the dividend yield declines, resulting in a lower ROE estimate using the DCF model. With respect to the CAPM and Risk Premium models, yields on Treasury bonds directly affect the calculation of the ROE under both models. Generally, low Treasury bond yields result in lower ROE estimates in the CAPM and Risk Premium models, unless there has been an offsetting increase in the risk premium.

A. Constant Growth DCF Model

I calculated DCF results for each of the proxy group companies using the following inputs:

1) Average stock prices for the historical period, over 30, 90 and 180 trading days through September 29, 2017;
2) Annualized dividend per share as of September 29, 2017; and
3) Company-specific earnings growth forecasts.

It is important to use an average of recent trading days to calculate the subject company's stock price in the DCF model to ensure that the calculated ROE is not skewed by anomalous events that may affect stock prices on any given trading day. At the same time, it is important to reflect the conditions that have defined the financial markets over the recent past. In my view, consideration of these three averaging periods reasonably balances those concerns.

Utility companies tend to increase their quarterly dividends at different times throughout the year, so it is reasonable to assume that such increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth for purposes of calculating this component of the DCF model. Accordingly, the DCF estimates reflect one-half of the expected growth in the dividend yield.

I have used the consensus analyst five-year growth estimates in earnings per share ("EPS") from Thomson First Call and Zacks, as well as EPS growth rates published by Value Line.

I relied on EPS growth rates because the Constant Growth DCF model assumes that dividends grow at a single growth rate in perpetuity. Accordingly, in order to reduce the long-term growth rate to a single measure, one must assume a constant payout ratio, and that EPS, dividends per share and book value per share will all grow at the same constant rate. It is therefore important to focus on measures of long-term earnings growth from credible sources as an appropriate measure of long-term growth in the DCF model.

I calculated the Mean High DCF result using the maximum growth rate (i.e., the maximum of the Value Line, Zacks and First Call EPS growth rates) in combination with the expected dividend yield for each of the proxy group companies. I used a similar approach to calculate the Mean Low DCF results, using the minimum growth rate for each company. The Mean DCF results reflect the average growth rate for each company in combination with the expected dividend yield.

The results of my Constant Growth DCF analysis are provided in Schedule 2 and summarized in Figure 5.

Figure 5: Constant Growth DCF Results

	Mean Low	Mean	Mean High
30-day average	7.12%	8.13%	9.14%
90-day average	7.17%	8.19%	9.20%
180-day average	7.26%	8.27%	9.28%

As discussed in Section IV of this report, the prolonged period of low interest rates has distorted the results of the DCF model. In particular, dividend yields for utility companies are well below historical levels, which reduces the Constant Growth DCF results. It is particularly important that the ROE in this proceeding be based on forward-looking expectations for interest rates. It would not be appropriate to base the ROE determination on models that only take into consideration historical data which is from a period when the interest rate environment was much different than investors are expecting in the near future. In this economic environment, it is not reasonable to conclude that current stock valuations and dividend yields are sustainable, especially in the face of higher interest rates. As such, my conclusion is that the Constant Growth DCF model does not produce reliable results because one of the fundamental assumptions of the Constant Growth DCF method is that the P/E ratio will remain constant.

Other regulators have recognized that anomalous capital market conditions are having an effect on the results of the DCF model. For example, the Federal Energy Regulatory Commission ("FERC") has determined that anomalous capital market conditions have caused the DCF model to understate equity costs for regulated utilities at this time:

> Though the Commission noted certain economic conditions in Opinion No. 531, the principle argument was based on low interest rates and bond yields, conditions that persisted throughout the study period. Consequently, we find that capital market conditions are still anomalous as described above…[17]

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[17] FERC Docket No. EL14-12-002, Opinion No. 551, at para 121. While Opinion No. 531 was recently remanded to the FERC by the D.C. Circuit Court, the DC court did not question the finding by the FERC that capital market conditions were anomalous.

> Because the evidence in this proceeding indicates that capital markets continue to reflect the type of unusual conditions that the Commission identified in Opinion No. 531, we remain concerned that a mechanical application of the DCF methodology would result in a return inconsistent with Hope and Bluefield.[18]
>
> ****
>
> As the Commission found in Opinion No. 531, under these circumstances, we have less confidence that the midpoint of the zone of reasonableness in this proceeding accurately reflects the equity returns necessary to meet the Hope and Bluefield capital attraction standards. We therefore find it necessary and reasonable to consider additional record evidence, including evidence of alternative methodologies…[19]

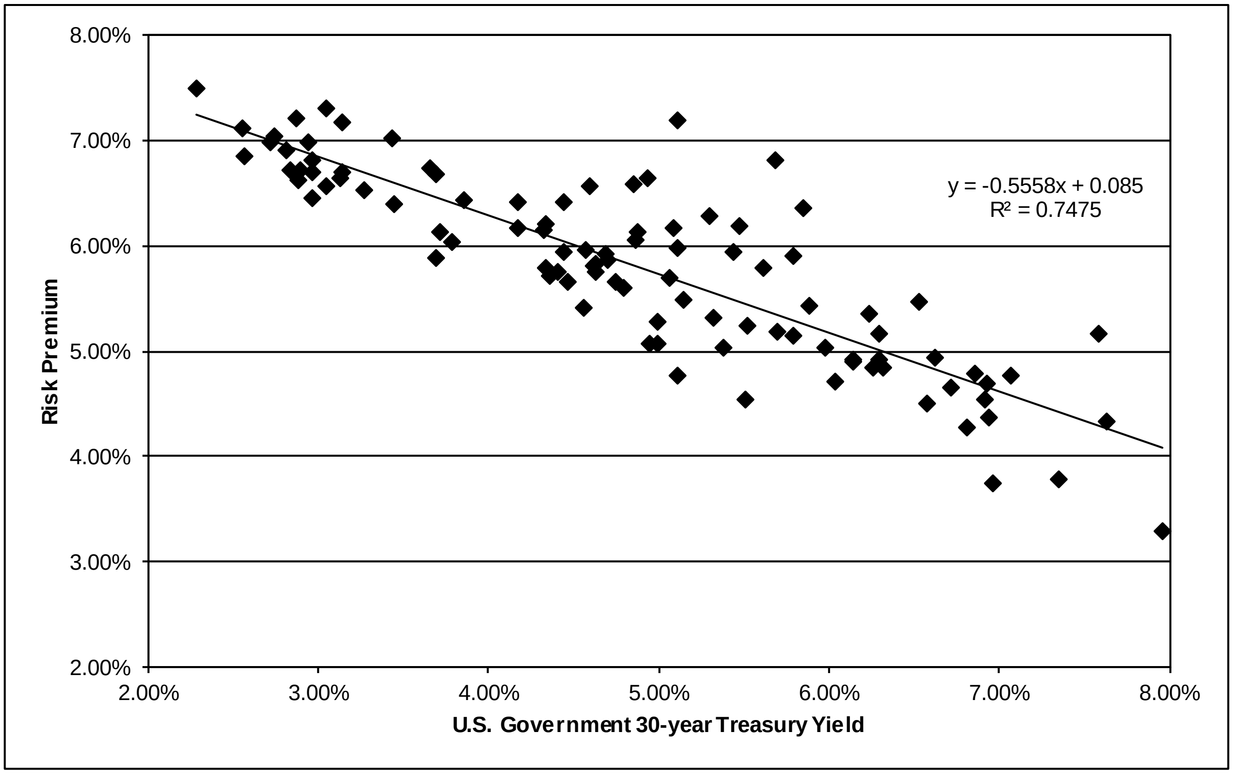
Following the FERC's logic in Opinion No. 551, yields on 10-year Treasury bonds remain well below 3.0 percent,[20] which is the level that the FERC determined represents "anomalous" capital market conditions. The results of the DCF model are understating the cost of equity under current market conditions due to the low interest rate environment that has reduced dividend yields and raised valuations on utility shares to unsustainable levels. Consequently, it is necessary to consider the results of Risk Premium models, such as the Risk Premium and CAPM analyses in order to determine where to set the appropriate return.

B. Risk Premium Analysis

I conducted two Risk Premium analyses. My first risk premium analysis examines the relationship between quarterly average allowed ROEs for vertically-integrated electric utility companies and the respective 30-year Treasury yield from the relevant quarter. Data regarding allowed ROEs were provided by Regulatory Research Associates. The data includes 664 vertically-integrated electric utility rate cases from 1993 through September 29, 2017. The results of that regression are detailed in Figure 6.

18 *Ibid.*, at para. 122.
19 *Ibid.*
20 10-year Treasury bond yield was 2.33% on September 29, 2017.

Figure 6: Risk Premium Regression Results vs. 30-Year Treasury Yield



As illustrated by the chart, the risk premium varies with the level of the bond yield, and generally increases as bond yields decrease, and vice versa. My analysis considers three estimates of the 30-year Treasury yield, including the current 30-day average, a "Near-Term" Blue Chip consensus forecast for Q4 2017-Q1 2019, and a "Long-Term" Blue Chip consensus forecast for 2019-2023. I find this "Long-Term" result to be most applicable because investors typically have a multi-year view of their required returns on equity. As shown in Schedule 3.1, page 2, from 1993 through September 29, 2017, the average implied risk premium over these historic Treasury yields is 5.80 percent. Based on the regression coefficients in Schedule 3.1, page 3, which allow for the estimation of the risk premium at varying bond yields, the results of my analysis are shown in Figure 7.

Figure 7: Risk Premium Results Using 30-Year Treasury Yield

	Using 30-Day Average Yield on 30-Year Treasury Bond	Using Near-Term Forecast for Yield on 30-Year Treasury Bond[21]	Using Long-Term Forecast for Yield 30-Year Treasury Bond[22]
Yield	2.77%	3.30%	4.30%
Risk Premium	6.96%	6.67%	6.11%
Resulting ROE	9.74%	9.97%	10.41%

As an alternative to the Treasury Yield Risk Premium analyses described above, I have performed a similar analysis using historical A-rated utility bond yields to calculate the risk premium against authorized ROEs for integrated electric utilities. A Blue Chip forecast, which I included in the Treasury yield version of the model, is not available for the A-rated utility bond yield. I therefore derived a forecast for the A-rated utility bond yield using average historical spreads from January 1, 2015 through September 29, 2017. The average spread between the 30-year Treasury bond yield and the A-rated utility bond yield during this period was 1.26 percent. I added this spread to the Blue Chip consensus forecasts referenced above to arrive at a Near-Term forecast of 4.56 percent and a Long-Term forecast of 5.56 percent. Inserting these forecasts for the A-rated utility bond yield into the regression equation provides the results shown in

My calculations are shown in Schedule 3.2. The results of this analysis reasonably track the Risk Premium results using the 30-Year Treasury Yield.

21 Blue Chip consensus forecast for 4Q 2017 – 1Q 2019, as of October 1, 2017.
22 Blue Chip consensus forecast for 2019 – 2023, as of June 1, 2017.

Figure 8: Risk Premium Results Using A-rated Utility Bond Yield

	Using 30-Day Average Yield on A-Rated Utility Bond	Using Near Term Forecast for A-Rated Utility Bond	Using Long-Term Forecast for A-Rated Utility Bond
Yield	3.86%	4.56%	5.56%
Risk Premium	5.77%	5.37%	4.80%
ROEs	9.62%	9.93%	10.36%

As noted earlier, I find that the Risk Premium results based on the 5-year forecast for the 30-year Treasury bond are applicable since they are forward-looking, and investors typically have a multi-year forward view of their estimates of the cost of equity. For purposes of my final range of analytical results, I draw from my Risk Premium model the results of 10.41 percent (based on Treasury yields) and 10.36 percent (based on Moody's A-rated utility bond yields).

C. <u>CAPM Analysis</u>

I also conducted a CAPM analysis for the two proxy groups.

Since both the DCF model and the CAPM assume long-term investment horizons, I used the Blue Chip forecast of the yield on 30-year Treasury bonds for 2019-2023 of 4.30 percent as my estimate of the risk-free rate.[23] Using the 5-year forecast of Treasury bond yields as the risk-free rate in the CAPM formula appropriately reflects the market's expectation for forward-looking interest rates.

I considered two measures of Beta for the proxy group companies: (1) the reported Beta from Bloomberg (which is calculated using 24 months of weekly data); and (2) the reported Beta from Value Line (which is calculated using 60 months of weekly data). My calculations for Beta are provided In Schedule 4.1.

To derive the Market Risk Premium ("MRP"), I conducted a Constant Growth DCF analysis on each of the S&P 500 companies and calculated the expected total market return, weighted by

[23] Blue Chip Financial Forecasts, June 1, 2017, at 14.

market capitalization. This total market return is based on current dividend yields and projected earnings growth for each company in the S&P 500 Index. A forward-looking MRP is calculated by subtracting the risk-free rate (based on the 5-year forecast of the 30-year Treasury bond) from the total market return. This analysis results in an 9.25 percent MRP, as shown In Schedule 4.2.

The CAPM is inherently a forward-looking model since it is designed to estimate investors' required equity return expectations. The MRP should, therefore, reflect investors' expected equity market returns relative to expected returns on Treasury securities, not historical return data. This is also consistent with the approach used by the FERC in developing a forward-looking MRP in Opinion No. 531.[24]

The CAPM results are shown in Schedule 4.3 and summarized in Figure 9.

Figure 9: Forward-Looking CAPM Results

Using Value Line Betas	10.78%
Using Bloomberg Betas	9.52%
Mean Result	10.15%

These forward-looking CAPM results for the electric proxy group are consistent with the Risk Premium results, but well above the Constant Growth DCF results.

D. <u>Flotation Costs</u>

Flotation costs are the costs associated with the sale of new issues of common stock. Those costs include out-of-pocket expenditures for preparation, filing, underwriting, and other costs of issuance of common stock. To the extent that a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) returns, thereby diminishing the utility's allowed return. To appropriately reflect flotation costs, the DCF calculation should be modified to provide a dividend yield that would reimburse investors for issuance costs. My flotation cost calculation is based on the costs of issuing equity that were

[24] FERC Opinion No. 531, at para. 108.

incurred by Xcel in the common equity issuances shown in Schedule 5. Those issuance costs were applied to my electric utility proxy group. Based on the issuance costs in Schedule 5, flotation costs for NSPM are approximately 0.10 percent (i.e., 10 basis points).

The need to reimburse investors for equity issuance costs has been recognized by the Commission in many, although not all, previous decisions.[25] I did not make an explicit adjustment for flotation costs. Rather, I took into consideration flotation costs in establishing my recommended ROE, which reflects the range of results from my Constant Growth DCF, CAPM, and Risk Premium analyses.

E. <u>Authorized Returns in Other Jurisdictions</u>

The Federal Energy Regulatory Commission ("FERC") has jurisdiction over interstate electric transmission assets, including those owned by NSPM. In September 2016, the FERC issued Opinion No. 551 in which it set the authorized base ROE for MISO transmission owners at 10.32 percent. This is a relevant benchmark for investors because it is specific to electric transmission investment by regulated utilities in this region of the country.

In Order No. 679, the FERC discussed the need for new transmission investment and the risks associated with electric transmission. The FERC stated:

> Section 219 requires the Commission to re-examine these and other policies to determine whether they continue to strike the appropriate balance in encouraging new transmission investment given the significant need for new transmission infrastructure in the Nation. We do so in recognition of the unique and substantial challenges faced by large new transmission projects. Siting major transmission lines is extraordinarily difficult, given the environmental and land use concerns associated with obtaining and permitting new rights-of-way.[26]
>
> These challenges and risks are underscored by the fact that, in many instances, new transmission projects will not be financed and constructed in

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25 Docket No. E-001/GR-10-276, Findings of Fact, Conclusions, and Order, at 9; Docket No. E002/GR-10-971, Findings of Fact, Conclusions, and Order, at 8; Docket No. E002/GR-08-1065, Findings of Fact, Conclusions of Law, and Order, at 10-11; Docket No. E017/GR-07-1178, Findings of Fact, Conclusions of Law, and Order, at 57-58; Docket No. G004/GR-04-1487, Findings of Fact, Conclusions of Law and Order, at 11.

26 Federal Energy Regulatory Commission, Order No. 679, Docket No. RM06-4-000, July 20, 2006, at para. 24.

> the traditional manner. New transmission is needed to connect new generation sources and to reduce congestion. However, because there is a competitive market for new generation facilities, these new generation sources may be located anywhere in a region that is economic with respect to fuel sources or other siting considerations (e.g., proximity to wind current), not simply on a "local" basis within each utility's service territory.[27]

> Thus, for the Nation to be able to integrate the next generation of resources, we must encourage investors to take the risks associated with constructing large new transmission projects that can integrate new generation and otherwise reduce congestion and increase reliability.[28]

> To address the substantial challenges and risks in constructing new transmission, the Final Rule identifies instances where our regulatory policies may no longer strike the appropriate balance in encouraging new investment.[29]

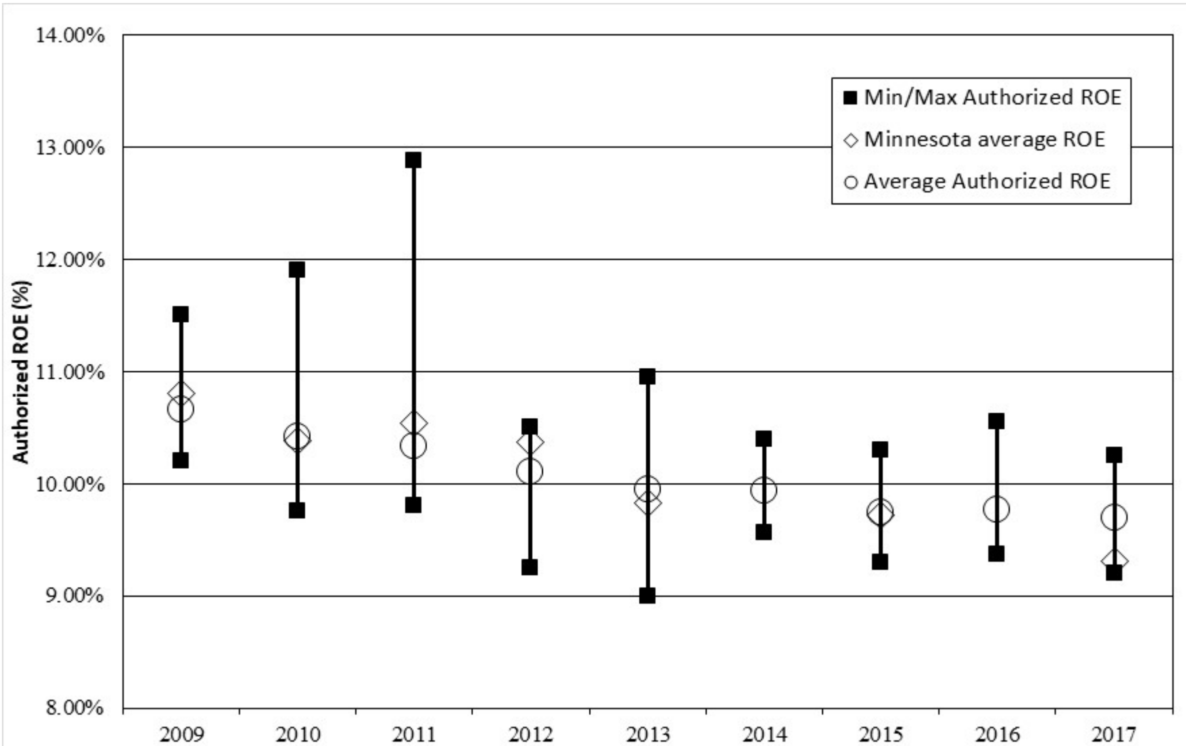
> The Final Rule permits higher returns on equity for certain transmission investments. This may be appropriate in several contexts, such as where the risks of a particular project exceed the normal risks undertaken by a utility (and hence are not reflected in the traditional discounted cash flow (DCF) analysis) and where necessary to encourage creation of a Transco or participation in a Transmission Organization.[30]

The risks of transmission development and operation cited by the FERC remain relevant today, and relevant for NSPM. Without any consideration for ISO participation, new project development risk or other factors the FERC would consider as "adders", the Company is allowed a 10.32 percent return on its core utility assets regulated by the FERC.

In addition, I also considered authorized returns for integrated electric utility companies in other state jurisdictions. Figure 10 shows the range of authorized returns for integrated electric utilities nationwide since January 2009, and the returns authorized in Minnesota for electric utilities over this same period. The national average authorized ROE for integrated electric utility companies in 2016 and 2017 has been 9.74 percent.

27 *Ibid*, at para. 25.
28 *Ibid*.
29 *Ibid*, at para. 26.
30 *Ibid*, at para. 27.

Figure 10: Comparison of Minnesota and U.S. Authorized Returns[31]



As shown in Figure 10, the authorized returns for electric utility companies in Minnesota have steadily declined from 2009 to 2017 and are currently near the bottom of the range produced by the authorized ROEs from other state jurisdictions. This is the result of the Commission's primary reliance on the results of the DCF analysis to determine a company's authorized ROE, rather than also considering whether the results of the DCF model are reasonable by reference to other models such as the CAPM and the Risk Premium model.

This should concern the Commission for two reasons. First, Minnesota utility subsidiaries must compete for capital within their own corporate structure, which must in turn compete for capital with other utilities and businesses. Placing NSPM at the low end of authorized ROEs outside Minnesota over the longer term can negatively impact NSPM's access to capital.

Second, as noted in Sections IV and VI, the historically low interest rates on Treasury bonds have resulted in high valuations of utility stocks, which has reduced dividend yields and therefore

[31] Source: SNL Financial.

the results produced by the DCF model. Given that interests rates are expected to increase over the period during which the Company's cost of equity for the TCR rider will be in effect, the results of the DCF model will underestimate an investor's expected ROE. As a result, it is important that the Commission consider the results of alternative methods such as the forward-looking CAPM and Risk Premium analyses.

VII. SUMMARY AND CONCLUSIONS

Figure 11 summarizes the mean results of my DCF, Risk Premium and CAPM analyses for the electric utility proxy group.

Figure 11: Summary of ROE Model Results

DCF Model – 90-day average stock price	
Constant Growth	8.19%
Risk Premium	
30 Yr. U.S. Treasury	10.41%
Moody's A-rated Utility Index	10.36%
CAPM	
Value Line Beta	10.78%
Bloomberg Beta	9.52%
Mean of All Methods	9.85%

The results range from a low of 8.19 percent for the Constant Growth DCF analysis to a high of 10.78 percent for the CAPM analysis. The mean of all methods for the proxy group is 9.85 percent. Other relevant benchmarks are the national average authorized ROE for integrated electric utilities in 2016 and 2017 of 9.74 percent, and the FERC-approved base ROE for MISO transmission owners of 10.32 percent in Opinion No. 551 issued September 2016. My ROE recommendation for the TCR rider is based on the following conclusions:

1) The results of the DCF model are under-estimating the cost of equity at this time given the current low dividend yields and high stock valuations for utility companies, which are not considered to be sustainable over the longer-term in the face of higher interest rates;
2) Risk Premium and CAPM methods that rely on forward-looking inputs for the risk-free rate should be given greater weight during a period when the DCF model is being distorted by anomalous conditions in capital markets and interest rates are projected to increase substantially from current levels;
3) Authorized returns for regulated electric utilities in other U.S. jurisdictions have averaged 9.74 percent over the January 2016 – September 2017 period. Given the increase in Treasury yields that has already occurred, this trailing average sets a lower boundary on a forward-looking equity return;
4) The FERC-approved base ROE for MISO transmission owners of 10.32 percent is another relevant benchmark because it pertains to federally-regulated transmission assets; and
5) Average yields on 10-year Treasury bonds have risen by 68 basis points from the third quarter of 2016 (when the electric rate case settlement was negotiated) to the third quarter of 2017. This supports a return above NSPM's last electric rate case settlement ROE of 9.20 percent.

On balance, I believe that an authorized ROE of 10.0 percent represents a fair determination of the Company's cost of equity for the TCR rider.

James M. Coyne
Senior Vice President

Mr. Coyne provides financial, regulatory, strategic, and litigation support services to clients in the natural gas, power, and utilities industries. Drawing upon his industry and regulatory expertise, he regularly advises utilities, public agencies and investors on business strategies, investment evaluations, and matters pertaining to rate and regulatory policy. Prior to Concentric, Mr. Coyne worked in senior consulting positions focused on North American utilities industries, in corporate planning for an integrated energy company, and in regulatory and policy positions in Maine and Massachusetts. He has authored numerous articles on the energy industry and provided testimony and expert reports before the Federal Energy Regulatory Commission and numerous jurisdictions in the U.S. and Canada. Mr. Coyne holds a B.S. in Business from Georgetown University with honors and an M.S. in Resource Economics from the University of New Hampshire.

Areas of Expertise

- **Energy Regulation**
  - Rate policy
  - Cost of capital
  - Incentive regulation
  - Fuels and power markets
- **Management and Business Strategy**
  - Fuels and power market assessments
  - Investment feasibility
  - Corporate and business unit planning
  - Benchmarking and productivity analysis
- **Financial and Economic Advisory**
  - Valuation analysis
  - Due diligence
  - Buy and sell-side advisory

REPRESENTATIVE PROJECT EXPERIENCE

Expert Testimony Experience

- Ontario Power Generation Inc.: Before the Ontario Energy Board, provided expert testimony on the appropriate common equity ratio for the company's regulated nuclear and hydroelectric generation assets, with Daniel Dane. (EB-2016-0152)
- Atco Electric Yukon: Before the Yukon Utilities Board, provided expert testimony on the appropriate risk premium to be applied to Atco Electric Yukon's return on equity in relation to utilities in other jurisdictions. (Docket 2016-2017 GRA)
- Vermont Gas Systems, Inc.: Before the Vermont Public Service Board, provided expert testimony on the cost of capital and business risk for the Company's gas distribution operations. (Docket No. 8698/8710)

- Northern States Power Co.: Before the Minnesota Public Utilities Commission, provided expert testimony on the cost of capital for the Company's electric distribution operations. (Docket No. E002/GR-15-826)
- Maritime Electric: Before the Island Regulatory and Appeals Commission, provided expert testimony on the cost of capital for the Company's electric distribution operations. (Docket No. UE20942)
- Newfoundland Power Inc.: Before the Newfoundland and Labrador Board of Commissioners of Public Utilities, provided expert testimony on the cost of capital and business risk for the Company's electric distribution operations. (2016/2017 General Rate Application)
- FortisBC Energy Inc.: Before the British Columbia Utilities Commission, provided expert testimony on the cost of capital and business risk for the Company's BC gas distribution operations. (Docket No. 3698852)
- Hydro-Québec: Before the Régie de l'énergie, filed expert testimony on performance based regulation recommendations for the Company's Québec electric transmission and distribution businesses, with Robert Yardley. (R-3897-2014)
- Green Mountain Power Company: Before the Vermont Public Service Board, provided expert testimony on the cost of capital for the Company's Vermont Electric Utility Business. (Docket No. 8191)
- Northern States Power Company: Before the Public Service Commission of Wisconsin, provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-119)
- Hydro-Québec: Before the Régie de l'énergie, filed expert testimony on the cost of capital and business risk for the Company's Québec electric transmission and distribution businesses, with John Trogonoski. (R-3842-2013)
- Enbridge: Before the Ontario Energy Board, filed expert testimony with Jim Simpson and Melissa Bartos in support of the Company's proposed 2nd Generation Incentive Regulation plan. Our work focused on development of a proposed plan consistent with the OEB's objectives for such plans, while recognizing the Company's operating environment and business objectives, and capitalizing on the experience with other IR programs. Concentric conducted a series of analyses, including industry benchmarking, and productivity analyses for the industry and Enbridge using both total factor productivity "TFP" analysis and partial factor productivity ("PFP") analysis. These analyses produced productivity measures ("X factors") for both Enbridge and the industry peer group that were utilized to test parameters for the proposed IR plan. Concentric also evaluated alternative measures of inflation ("I factors") for utility inputs. Lastly, we examined Enbridge's anticipated 2014 to 2016 costs, and evaluated the ability of a traditional I-X framework to accommodate the Company's cost profile. (EB-2012-0459)
- Gaz Métro: Before the Régie de l'énergie, filed expert testimony on the cost of capital, business risk, and capital structure for the Company's Québec gas distribution operations. (R-3809-2012)
- Startrans IO, LLC: Before the Federal Energy Regulatory Commission, filed expert testimony on the appropriate cost of equity for the Startrans transmission facilities in Nevada and California, and the economic and business environment for transmission investments. (FERC Dockets Nos. ER13-272-000, and EL13-26-000)

- Nova Scotia Power: Before the Nova Scotia Utility and Review Board, provided direct and rebuttal evidence on the business risk of Nova Scotia Power in relation to its North American peers for purposes of determining the appropriate cost of capital. (Docket No. 2013 GRA)
- FortisBC Utilities: Before the British Columbia Utilities Commission, provided direct evidence and a supporting study on formulaic approaches to the determination of the cost of capital. (BCUC 2012 Generic Cost of Capital Proceeding)
- Northern States Power Company: Before the South Dakota Public Utilities Commission provided expert testimony on the appropriate cost of capital for the company's South Dakota electric utility operations. (Docket No. EL12 -)
- Vermont Gas Systems, Inc: Before the Vermont Public Service Board, filed expert testimony on the appropriate cost of equity and capital structure. (Docket No. 7803A)
- Northern States Power Company: Before the South Dakota Public Utilities Commission, provided expert testimony on the appropriate cost of capital for the company's South Dakota electric utility operations. (Docket No. EL11-019)
- Public Service Commission of Wisconsin: Provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-117)
- Atlantic Path 15, LLC: Before the Federal Energy Regulatory Commission, filed expert testimony on the appropriate rate of return for the Path 15 transmission facilities in California, and the economic and business environment for transmission investments. (FERC Dockets Nos. ER11-2909 and EL11-29)
- Enbridge: Cost of capital witness for the company's 2013 rate filing, providing testimony on recommended ROE and capital structure for the company's Ontario gas distribution business, and a separate benchmarking analysis designed to illustrate the efficiency of the company's operations in relation to its' North American peers. (EB-2011-0354)
- Northern States Power Company: Before the Public Service Commission of Wisconsin, provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-117)
- FortisBC Energy, Inc: Provided a detailed study of alternative automatic adjustment mechanisms for setting the cost of equity, filed with the British Columbia Public Utilities Commission, December, 2010. (In response to BCUC Order No. G-158-09)
- Commonwealth of Massachusetts, Superior Court, Central Water District vs. Burncoat Pond Watershed District: Provided expert testimony on the appropriate method for computing interest in an eminent domain taking. (Civil Action No. WDCV2001-01051, May 2010)
- Retained by the Ontario Energy Board to evaluate the existing DSM regulatory framework and guidelines for gas distributors, and based on research on best practices in other jurisdictions, make recommendations and lead a stakeholder conference on proposed changes. (2009-2010)
- ATCO Utilities: Primary cost of capital witness on behalf of ATCO Utilities in the 2009 Alberta Generic Cost of Capital proceeding, for the establishment of the return on equity and capital structure for each of Alberta's gas and electric utilities. (AUC Proceeding ID. 85)
- Enbridge: Primary cost of capital witness before the Ontario Energy Board in its Consultative Process on the Board's policy for determination of the cost of capital. (EB-2009-0084)
- Provided written comments to the Ontario Energy Board on behalf of Enbridge Gas Distribution, and separately for Hydro One Networks and the Coalition of Large Distributors

in response to the Board's invitation to interested stakeholders to provide comments to help the Board better understand whether current economic and financial market conditions have an impact on the reasonableness of the Cost of Capital parameter values calculated in accordance with the Board's established Cost of Capital methodology; and to help the Board determine if, when, and how to make any appropriate adjustments to those parameter values. (2009)

- Atlantic Path 15, LLC: Before the Federal Energy Regulatory Commission, provided expert testimony on the appropriate rate of return, capital structure, and rate incentives for the development and operation of the Path 15 transmission facilities in California. (FERC Docket ER08-374-000)
- Wisconsin Power and Light Company: Before the Public Service Commission of Wisconsin, on establishing ratemaking principles for the company's proposed wind and coal electric generation facility additions, providing expert testimony on the appropriate return on equity. (PSCW Docket Nos. 6680-CE-170 and 6680-CE-171, 2007)
- Aquarion Water Company: Before the Connecticut Department of Public Utility Control, providing expert testimony on establishing the appropriate return on equity for the Company's Connecticut operations. (DPUC Docket No. 07-05-19, 2007)
- Central Maine Power Company: Before the Maine Public Utilities Commission, provided expert testimony on the theoretical and analytical soundness of the Company's sales forecast for ratemaking purposes. (MPUC Docket No. 2007-215, 2007)
- Vermont Gas Systems, Inc.: Before the State of Vermont Public Board, on the company's petition for approval of an alternative regulation plan, provided expert testimony on models of incentive regulation and their relative benefits for VGS and its ratepayers. (VPSB Docket No. 7109, 2006)
- Texas New Mexico Power Company: Before the Public Utility Commission of Texas, on the approval of the company's stranded cost recovery associated with the auction of the company's generating assets. (PUC Docket No. 29206, 2004)
- TransCanada Corporation: Provided an independent expert valuation of a natural gas pipeline, filed with the American Arbitration Association. (AAA Case No. 50T 1810018804, 2004)
- Advised the Board of Directors of El Paso Corporation on settlement matters pertaining to western power and gas markets before FERC. (2003)
- Conectiv: Before the New Jersey Board of Public Utilities, on the approval of the proposed sale of Atlantic City Electric Company's fossil and nuclear generating assets. (NJBPU Docket No. EM00020106, 2000-2001)
- Bangor Hydro Electric Company: Before the Maine Public Utilities Commission, on the approval of the proposed sale of the company's hydroelectric and fossil generation assets. (MPUC Docket No. 98-820, 1998)
- Maine Office of Energy Resources: Before the Maine Public Utilities Commission on behalf of the Maine Office of Energy on the establishment of avoided costs rates for generators under PURPA. (1981-1982)

Regulatory Support Experience

- Provided consulting services to Hydro One Networks for the Company's 2015 – 2019 Custom Distribution Rate Application to the OEB. Assisted the Company in developing its proposal for specific performance metrics for the Plan; reviewed the comments of stakeholders on performance metrics; reviewed the Company's existing performance metrics; reviewed the fastest growing areas of budgeted expenditures for their performance metric potential; developed a set of recommended metrics for review with the Company; and assisted the Company with drafting its submission to the OEB. (2014)

- Advised the Ontario Power Authority (OPA) on appropriate efficiency metrics to utilize in measuring the effectiveness of the organization in response to a directive by the Ontario Energy Board. Conducted research and analysis to examine efficiency metrics used in the industry to measure the effectiveness of organizations with similar responsibilities to those of the OPA. This analysis was designed to help facilitate the OPA's recommended metrics to the OEB. (2013)
- Retained by Gaz Métro to provide an independent assessment of the comprehensive incentive rate mechanism designed to improve the performance of Gaz Métro, and evaluate the proposed mechanism resulting from the Company's collaboration with a stakeholder working group. (R-3693-2009, 2011)
- For the Canadian Gas Association, facilitated workshops between Canadian regulators and utility executives on regulatory and utility responses to a low carbon world, and drafted follow-up white paper to facilitate further discussion on emerging industry issues. (2010-2013)
- Retained by Ontario's Coalition of Large Distributors (Enersource Hydro, Horizon Utilities, Hydro Ottawa, PowerStream, Toronto Hydro, and Veridian Connections) to examine the cost of capital for Ontario's electric utilities in relation to those in other provinces and in the U.S. (2008)
- Retained by the Ontario Energy Board to analyze ROE awards for the past two years in Ontario, and compare against other jurisdictions in Canada, the U.S., the U.K., and select other European jurisdictions. Differences in awarded ROEs were examined for underlying factors, including ROE methodology, company size, business risks, tax issues, subsidiary vs. parent, and sources of capital. The analysis also addressed the question of whether Canadian utilities compete for capital on the same basis as U.S. utilities. (2007)
- Retained by the Nantucket Planning and Economic Development Commission to educate government officials and island residents on the wind industry, and provide analysis leading to constructive input to the Army Corps of Engineers and the Minerals Management Service on the siting of proposed wind projects. (2004-2007)
- Interim manager of Government and Regulatory affairs for Boston Generating, LLC. Coordinate activities and interventions before FERC, NE-ISO, state regulatory agencies, and local communities hosting Boston Generating power plants. (2004)
- Facilitated the development of an Alternative Regulation Plan with the Department of Public Service and Vermont Gas Systems providing research and advice leading to a rate proposal for the Vermont Public Service Board. Conducted several workshops including the major stakeholders and regulatory agencies to develop solutions satisfying both public policy and utility objectives. (2004-2005)
- For an independent power company, perform market analysis and annual audits of its utility power contract. Services provided include verification of the contract price as a function of its index components, surveys of regional competitive energy suppliers, and analysis of regional spot prices for an independent benchmark. Meet with PUC staff to discuss and represent the company in its annual adjustment process, and report results to the company and its creditors. (2003-2004)

PUBLICATIONS AND RESEARCH

- "Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Consumers" (with Robert Yardley), prepared for the Canadian Gas Association and Canadian Electricity Association, May, 2015.
- "Autopilot Error: Why Similar U.S. and Canadian Risk Profiles Yield Varied Rate-making Results" (with John Trogonoski), Public Utilities Fortnightly, May 2010
- "A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Dan Dane and Julie Lieberman), prepared for the Ontario Energy Board, June, 2007
- "Do Utilities Mergers Deliver?" (with Prescott Hartshorne), Public Utilities Fortnightly, June 2006
- "Winners and Losers: Utility Strategy and Shareholder Return" (with Prescott Hartshorne), Public Utilities Fortnightly, October 2004
- "Winners and Losers in Restructuring: Assessing Electric and Gas Company Financial Performance" (with Prescott Hartshorne), white paper distributed to clients and press, August 2003
- "The New Generation Business," commissioned by the Electric Power Research Institute (EPRI) and distributed to EPRI members to contribute to a series on the changes in the Power Industry, December 2001
- Potential for Natural Gas in the United States, Volume V, Regulatory and Policy Issues (co-author), National Petroleum Council, December 1992
- "Natural Gas Outlook," articles on U.S. natural gas markets, published quarterly in the Data Resources Energy Review and Natural Gas Review, 1984-1989

SELECTED SPEAKING ENGAGEMENTS

- "Understanding Regulated Utilities in Today's Capital Markets", NARUC Annual Meeting, La Quinta, CA, November 14, 2016.
- "Rate of Return: Where the Regulatory Rubber Meets the Road", CAMPUT Annual Conference, Montreal, Quebec, May 17, 2016.
- "Innovations in Utility Business Models and Regulation", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2015 Energy Regulation Course, Queens University, Kingston, Ontario, June 2015
- "M&A and Valuations," Panelist at Infocast Utility Scale Solar Summit, September 2010
- "The Use of Expert Evidence," The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2010 Energy Regulation Course, Queens University, Kingston, Ontario, June 2010
- "A Comparative Analysis of Return on Equity for Utilities in Canada and the U.S.", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) Annual Conference, Banff, Alberta, April 22, 2008
- "Nuclear Power on the Verge of a New Era," moderator for a client event co-hosted by Sutherland Asbill & Brennan and Lexecon, Washington D.C., October 2005
- "The Investment Implications of the Repeal of PUCHA," Skadden Arps Client Conference, New York, NY, October 2005
- "Anatomy of the Deal," First Annual Energy Transactions Conference, Newport, RI, May 2005

- "The Outlook for Wind Power," Skadden Arps Annual Energy and Project Finance Seminar, Naples, FL, March 2005
- "Direction of U.S. M&A Activity for Utilities," Energy and Mineral Law Foundation Conference, Sanibel Island, FL, February 2002
- "Outlook for U.S. Merger & Acquisition Activity," Utility Mergers & Acquisitions Conference, San Antonio, TX, October 2001
- "Investor Perspectives on Emerging Energy Companies," Panel Moderator at Energy Venture Conference, Boston, MA, June 2001
- "Electric Generation Asset Transactions: A Practical Guide," workshop conducted at the 1999 Thai Electricity and Gas Investment Briefing, Bangkok, Thailand, July 1999
- "New Strategic Options for the Power Sector," Electric Utility Business Environment Conference, Denver, CO, May 1999
- "Electric and Gas Industries: Moving Forward Together," New England Gas Association Annual Meeting, November 1998
- "Opportunities and Challenges in the Electric Marketplace," Electric Power Research Institute, July 1998

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2006 – Present)
Senior Vice President
Vice President

FTI Consulting (Lexecon) (2002 – 2006)
Senior Managing Director – Energy Practice

Arthur Andersen LLP (2000 – 2002)
Managing Director, Andersen Corporate Finance – Energy and Utilities

Navigant Consulting, Inc. (1996 – 2000)
Managing Director, Financial Services Practice
Senior Vice President, Strategy Practice

TotalFinaElf (1990 – 1996)
Manager, Corporate Planning and Development
Manager, Investor Relations
Manager of Strategic Planning and Vice President, Natural Gas Division

Arthur D. Little, Inc. (1989 – 1990)
Senior Consultant – International Energy Practice

DRI/McGraw-Hill (1984 – 1989)
Director, North American Natural Gas Consulting
Senior Economist, U.S. Electricity Service

Massachusetts Energy Facilities Siting Council (1982 – 1984)
Senior Economist – Gas and Electric Utilities

Maine Office of Energy Resources (1981 – 1982)
State Energy Economist

EDUCATION

M.S., Resource Economics, University of New Hampshire, with Honors, 1981
B.S., Business Administration and Economics, Georgetown University, Cum Laude, 1975

DESIGNATIONS AND AFFILIATIONS

NASD General Securities Representative and Managing Principal (Series 7, 63 and 24 Certifications), 2001
NARUC, Advanced Regulatory Studies Program, Michigan State University, 1984
American Petroleum Institute, CEO's Liaison to Management and Policy Committees, 1994-1996
National Petroleum Council, Regulatory and Policy Task Forces, 1992
President, International Association for Energy Economics, Dallas Chapter, 1995
Gas Research Institute, Economics Advisory Committee, 1990-1993
Georgetown University, Alumni Admissions Interviewer, 1988 – current

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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Alberta Beverage Container Management Board				
Alberta Beverage Container Management Board	2016	Expert for the Board	N/A	Return Margin on Bottle Depots
Alberta Utilities Commission				
ATCO Utilities Group	2008 2009	ATCO Gas; ATCO Pipelines Ltd.; ATCO Electric Ltd.	Application No. 1578571 / Proceeding ID. 85	2009 Generic Cost of Capital Proceeding (Gas & Electric)
American Arbitration Association				
TransCanada Corporation	2004	TransCanada Corporation	AAA Case No. 50T 1810018804	Valuation of Natural Gas Pipeline
British Columbia Utilities Commission				
FortisBC	2012	FortisBC Utilities	G-20-12	Cost of Capital Adjustment Mechanisms
FortisBC	2015 2016	FortisBC Utilities	Project 3698852	Cost of Capital (Gas Distribution)
Connecticut Department of Public Utility Control				
Aquarion Water Company of CT/ Macquarie Securities	2007	Aquarion Water Company of CT	DPUC Docket No. 07-05-19	Return on Equity (Water)
Federal Energy Regulatory Commission				
Atlantic Power Corporation	2007	Atlantic Path 15, LLC	ER08-374-000	Return on Equity (Electric)
Atlantic Power Corporation	2010	Atlantic Path 15, LLC	Docket No. ER11-2909-000	Return on Equity (Electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Atlantic Power Corporation	2011	Atlantic Path 15, LLC	Docket Nos. ER11-2909 and EL11-29	Rate of Return (Electric Transmission)
Startrans IO, LLC	2012	Startrans IO, LLC	ER-13-272-000	Cost of Capital (Electric Transmission)
Startrans IO, LLC	2015	Startran IO, LLC	ER-16-194-000 and EL16-25-000	Cost of Capital (Electric Transmission)
Maine Public Utility Commission				
Bangor Hydro Electric Company	1998	Bangor Hydro Electric Company	MPUC Docket No. 98-820	Transaction-Related Financial Advisory Services, Valuation
Central Maine Power Company	2007	Central Maine Power Company	MPUC Docket No. 2007-215	Sales Forecast
Massachusetts Superior Court				
Burncoat Pond Watershed District	2010	Central Water District v. Burncoat Pond Watershed District	WDCV 2001-0105	Valuation/Eminent Domain
Minnesota Public Utilities Commission				
Northern States Power Company	2015 2016	Northern States Power Company	E-002-GR-15-826	Cost of Capital (Electric)
Newfoundland and Labrador Board of Commissioners of Public Utilities				
Newfoundland Power	2015 2016	Newfoundland Power	2016/2017 GRA	Cost of Capital (Electric)
New Jersey Board of Public Utilities				
Conectiv	2000-2001	Atlantic City Electric Company	NJBPU Docket No. EM00020106	Transaction-Related Financial Advisory Services

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Nova Scotia Utility and Review Board				
Nova Scotia Power Inc.	2012	Nova Scotia Power Inc.	2013 GRA	Return on Equity/Business Risk (Electric)
Ontario Energy Board				
Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	2009	Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	EB-2009-0084	Ontario Energy Board's 2009 Consultative Process on Cost of Capital Review (Gas & Electric)
Enbridge Gas Distribution	2012	Enbridge Gas Distribution	EB-2011-0354	Industry Benchmarking Study and Cost of Capital (Gas Distribution)
Enbridge Gas Distribution	2014	Enbridge Gas Distribution	EB-2012-0459	Incentive Regulation Plan and Industry Productivity Study
Ontario Power Generation	2016	Ontario Power Generation	EB-2016-0152	Cost of Capital (Electric Generation)
Prince Edward Island Regulatory and Appeals Commission				
Maritime Electric Company	2015	Maritime Electric Company	UE20942	Return on Capital (Electric)
Régie de l'énergie du Québec				
Gaz Métro	2012	Gaz Métro	R-3809-2012	Return on Equity/Business Risk/ Capital Structure (Gas Distribution)
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2013	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3842-2013	Return on Equity/Business Risk (Electric)
Hydro-Québec Distribution	2014	Hydro-Québec Distribution	R-3905-2014	Remuneration of Deferral Accounts
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2015 2016	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3897-2014	Performance-Based Ratemaking
South Dakota Public Service Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Northern States Power Company-MN	2012	Northern States Power Company-MN	EL 11-019	Return on Equity
Texas Public Utility Commission				
Texas New Mexico Power Company	2004	Texas New Mexico Power Company	PUC Docket No. 29206	Auction Process and Stranded Cost Recovery
Vermont Public Service Board				
Vermont Gas Systems, Inc.	2006	Vermont Gas Systems, Inc.	VPSB Docket No. 7109	Models of Incentive Regulation
Vermont Gas Systems, Inc.	2012	Vermont Gas Systems, Inc.	Docket No. 7803A	Cost of Capital (Gas Distribution)
Green Mountain Power Corporation	2013	Green Mountain Power Corporation	Docket No. 8191	Return on Equity (Electric)
Vermont Gas Systems, Inc.	2016	Vermont Gas Systems, Inc.	Docket No. 8698/8710	Return on Equity (Gas Distribution)
Green Mountain Power Corporation	2017	Green Mountain Power Corporation	Docket No. Tariff-8677	Return on Equity (Electric)
Wisconsin Public Service Commission				
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-170	Return on Equity (Electric)
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-171	Return on Equity (Electric)
Northern States Power Company	2011	Northern States Power Company	PSCW Docket No. 4220-UR-117	Return on Equity (Electric)
Northern States Power Company	2013	Northern States Power Company	PSCW Docket No. 4220-UR-119	Return on Equity (Gas & Electric)
Northern States Power Company	2015	Northern States Power Company	PSCW Docket No. 4220-UR-121	Return on Equity (Gas & Electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Northern States Power Company	2017	Northern States Power Company	PSCW Docket No. 4220-UR-123	Return on Equity (Gas & Electric)
Yukon Utilities Board				
ATCO Electric Yukon	2016	ATCO Electric Yukon	2016-2017 GRA	Return on Equity (Electric)

Description of Models and Associated Methodology Used to Estimate Return on Equity

Constant Growth DCF Model

The DCF approach, which is widely used in regulatory proceedings, is based on the theory that a stock's price represents the present value of all future expected cash flows. In its simplest form, the DCF model expresses the ROE as the sum of the expected dividend yield and long-term growth rate, as reflected in the following formula, where "k" equals the required return, "D" is the current dividend, "g" is the expected growth rate, and "P" is the subject company's stock price:

$$k = \frac{D(1+g)}{P} + g$$

Assuming a constant growth rate in dividends, the model may be rearranged to compute the ROE accordingly, as shown in the following formula:

$$r = \frac{D}{P} + \mathrm{g}$$

Stated in this manner, the cost of common equity is equal to the dividend yield plus the dividend growth rate. The Constant Growth DCF model is based on the following assumptions: (1) a constant average growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings multiple; and (4) a discount rate greater than the expected growth rate.

Risk Premium Approach

In general terms, this approach recognizes that equity is riskier than debt because equity investors bear the residual risk associated with ownership. Equity investors, therefore, require a greater return (*i.e.*, a premium) than a bondholder would. The Risk Premium approach estimates the cost of equity as the sum of the Equity Risk Premium and the yield on a particular class of bonds, as reflected in the following formula, in which *RP* = Risk Premium (difference between allowed ROE and the respective bond yield); and Y = Applicable bond yield:

$$\text{ROE} = \text{RP} + \text{Y}$$

Since the equity risk premium is not directly observable, it typically is estimated using a variety of approaches, some of which incorporate ex-ante, or forward-looking estimates of the cost of equity, and others that consider historical, or ex-post, estimates. This Commission has previously recognized an approach that uses actual authorized returns for utilities as the measure of the Equity Risk Premium. The analysis therefore relies on authorized returns from a large sample of U.S. electric utilities, and separately on authorized returns for Wisconsin utilities only.

To estimate the relationship between interest rates and the cost of equity using the risk premium approach, a regression is conducted using the following equation, where a = intercept term and b = slope term:

$$RP = \mathrm{a} + (\mathrm{b} \times \mathrm{Y})$$

CAPM Analysis

The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium (to compensate investors for the non-diversifiable or "systematic" risk of that security).[1] As shown in the following equation, the CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f)$$

where:

K_e = the required ROE for a given security;

r_f = the risk-free rate of return;

β = the Beta of an individual security; and

r_m = the required return for the market as a whole.

1 Systematic risks are fundamental market risks that reflect aggregate economic measures and therefore cannot be mitigated through diversification. Unsystematic risks reflect company-specific risks that can be mitigated and ultimately eliminated through investments in a portfolio of companies and/or market sectors.

The term ($r_m - r_f$) represents the Market Risk Premium ("MRP"). According to the theory underlying the CAPM, since unsystematic risk can be diversified away, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by Beta, which is defined as:

$$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)}$$

where:

r_e = the rate of return for the individual security or portfolio.

The variance of the market return, noted in the above equation, is a measure of the uncertainty of the general market, and the covariance between the return on a specific security and the market reflects the extent to which the return on that security will respond to a given change in the market return. Thus, Beta represents the risk of the security relative to the market.

PROXY GROUP SCREENING DATA AND RESULTS - FINAL PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Dividends	S&P Credit Rating Between BBB- and AAA	Covered by More Than 1 Analyst	Positive Growth Rates from at least two sources (Value Line, Yahoo! First Call, and Zacks)	Company Owns Generation Assets in Rate Base	Company-Owned Generation > 25% of MWh Sales to Ultimate Customers	% Regulated Revenue > 60%	% Regulated Operating Income > 60%	% Regulated Electric Revenue > 80%	% Regulated Electric Operating Income > 80%	Announced Merger within 180 days from 9/29/2017
ALLETE, Inc.	ALE	Yes	BBB+	Yes	Yes	Yes	62%	77%	88%	97%	97%	No
Alliant Energy Corporation	LNT	Yes	A-	Yes	Yes	Yes	57%	99%	100%	85%	92%	No
Ameren Corporation	AEE	Yes	BBB+	Yes	Yes	Yes	77%	101%	101%	84%	89%	No
American Electric Power Company, Inc.	AEP	Yes	A-	Yes	Yes	Yes	65%	87%	133%	100%	100%	No
Duke Energy Corporation	DUK	Yes	A-	Yes	Yes	Yes	85%	98%	108%	97%	97%	No
El Paso Electric Company	EE	Yes	BBB	Yes	Yes	Yes	81%	100%	100%	100%	100%	No
Hawaiian Electric Industries, Inc.	HE	Yes	BBB-	Yes	Yes	Yes	54%	90%	83%	100%	100%	No
IDACORP, Inc.	IDA	Yes	BBB	Yes	Yes	Yes	75%	100%	99%	100%	100%	No
OGE Energy Corporation	OGE	Yes	A-	Yes	Yes	Yes	70%	100%	102%	100%	100%	No
Pinnacle West Capital Corporation	PNW	Yes	A-	Yes	Yes	Yes	77%	100%	100%	100%	100%	No
PNM Resources, Inc.	PNM	Yes	BBB+	Yes	Yes	Yes	82%	100%	100%	100%	100%	No
Portland General Electric Company	POR	Yes	BBB	Yes	Yes	Yes	54%	100%	100%	100%	100%	No
PPL Corporation	PPL	Yes	A-	Yes	Yes	Yes	44%	68%	110%	94%	95%	No
Southern Company	SO	Yes	A-	Yes	Yes	Yes	83%	93%	96%	97%	98%	No

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: Yahoo! Finance and Zacks
[4] Source: Yahoo! Finance, Value Line Investment Survey, and Zacks
[5] Source: SNL Financial (pulled from FERC Form 1)
[6] Source: SNL Financial (pulled from FERC Form 1) 2014-2016 three-year average
[7] - [10] Source: Form 10-Ks for 2016, 2015 & 2014, three-year average
[11] SNL Financial News Releases

30-DAY CONSTANT GROWTH DCF

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] Yahoo! Finance Earnings Growth	[7] Zacks Earnings Growth	[8] Average Growth Rate	[9] Mean Low ROE	[10] Overall Mean ROE	[11] Mean High ROE
ALLETE, Inc.	ALE	$2.14	$77.39	2.77%	2.84%	6.00%	5.00%	6.10%	5.70%	7.83%	8.54%	8.95%
Alliant Energy Corporation	LNT	$1.26	$42.56	2.96%	3.05%	6.00%	6.90%	5.50%	6.13%	8.54%	9.18%	9.96%
Ameren Corporation	AEE	$1.76	$59.52	2.96%	3.05%	6.00%	6.10%	6.50%	6.20%	9.05%	9.25%	9.55%
American Electric Power Company, Inc.	AEP	$2.36	$72.66	3.25%	3.31%	4.00%	2.87%	5.40%	4.09%	6.16%	7.40%	8.74%
Duke Energy Corporation	DUK	$3.56	$86.41	4.12%	4.20%	4.50%	2.65%	4.00%	3.72%	6.82%	7.91%	8.71%
El Paso Electric Company	EE	$1.34	$55.14	2.43%	2.51%	5.00%	6.50%	7.20%	6.23%	7.49%	8.74%	9.72%
Hawaiian Electric Industries, Inc.	HE	$1.24	$33.54	3.70%	3.74%	1.50%	1.40%	4.00%	2.30%	5.12%	6.04%	7.77%
IDACORP, Inc.	IDA	$2.20	$89.09	2.47%	2.52%	3.50%	4.00%	4.50%	4.00%	6.01%	6.52%	7.03%
OGE Energy Corporation	OGE	$1.21	$36.07	3.35%	3.45%	6.00%	6.30%	5.30%	5.87%	8.74%	9.32%	9.76%
Pinnacle West Capital Corporation	PNW	$2.62	$88.58	2.96%	3.04%	5.50%	6.04%	5.20%	5.58%	8.23%	8.62%	9.09%
PNM Resources, Inc.	PNM	$0.97	$42.01	2.31%	2.39%	9.00%	7.35%	4.70%	7.02%	7.06%	9.41%	11.41%
Portland General Electric Company	POR	$1.36	$46.85	2.90%	2.97%	6.00%	4.90%	3.50%	4.80%	6.45%	7.77%	8.99%
PPL Corporation	PPL	$1.58	$39.04	4.05%	4.10%	NMF	0.04%	5.00%	2.52%	4.09%	6.62%	9.15%
Southern Company	SO	$2.32	$49.04	4.73%	4.82%	3.50%	3.22%	4.30%	3.67%	8.03%	8.49%	9.13%
MEAN				3.21%	3.29%	5.12%	4.52%	5.09%	4.85%	7.12%	8.13%	9.14%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of September 29, 2017
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7])) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7])) + Maximum ([5], [6], [7])

90-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Mean Low ROE	Overall Mean ROE	Mean High ROE
ALLETE, Inc.	ALE	$2.14	$74.35	2.88%	2.96%	6.00%	5.00%	6.10%	5.70%	7.95%	8.66%	9.07%
Alliant Energy Corporation	LNT	$1.26	$41.54	3.03%	3.13%	6.00%	6.90%	5.50%	6.13%	8.62%	9.26%	10.04%
Ameren Corporation	AEE	$1.76	$57.35	3.07%	3.16%	6.00%	6.10%	6.50%	6.20%	9.16%	9.36%	9.67%
American Electric Power Company, Inc.	AEP	$2.36	$71.34	3.31%	3.38%	4.00%	2.87%	5.40%	4.09%	6.23%	7.47%	8.80%
Duke Energy Corporation	DUK	$3.56	$85.68	4.16%	4.23%	4.50%	2.65%	4.00%	3.72%	6.86%	7.95%	8.75%
El Paso Electric Company	EE	$1.34	$53.56	2.50%	2.58%	5.00%	6.50%	7.20%	6.23%	7.56%	8.81%	9.79%
Hawaiian Electric Industries, Inc.	HE	$1.24	$33.13	3.74%	3.79%	1.50%	1.40%	4.00%	2.30%	5.17%	6.09%	7.82%
IDACORP, Inc.	IDA	$2.20	$87.63	2.51%	2.56%	3.50%	4.00%	4.50%	4.00%	6.05%	6.56%	7.07%
OGE Energy Corporation	OGE	$1.21	$35.62	3.40%	3.50%	6.00%	6.30%	5.30%	5.87%	8.79%	9.36%	9.80%
Pinnacle West Capital Corporation	PNW	$2.62	$87.68	2.99%	3.07%	5.50%	6.04%	5.20%	5.58%	8.27%	8.65%	9.12%
PNM Resources, Inc.	PNM	$0.97	$40.17	2.41%	2.50%	9.00%	7.35%	4.70%	7.02%	7.17%	9.52%	11.52%
Portland General Electric Company	POR	$1.36	$46.38	2.93%	3.00%	6.00%	4.90%	3.50%	4.80%	6.48%	7.80%	9.02%
PPL Corporation	PPL	$1.58	$38.89	4.06%	4.11%	NMF	0.04%	5.00%	2.52%	4.10%	6.63%	9.16%
Southern Company	SO	$2.32	$49.09	4.73%	4.81%	3.50%	3.22%	4.30%	3.67%	8.02%	8.49%	9.13%
MEAN				3.27%	3.34%	5.12%	4.52%	5.09%	4.85%	7.17%	8.19%	9.20%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-day average as of September 29, 2017
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7])) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7])) + Maximum ([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Mean Low ROE	Overall Mean ROE	Mean High ROE
ALLETE, Inc.	ALE	$2.14	$70.80	3.02%	3.11%	6.00%	5.00%	6.10%	5.70%	8.10%	8.81%	9.21%
Alliant Energy Corporation	LNT	$1.26	$40.26	3.13%	3.23%	6.00%	6.90%	5.50%	6.13%	8.72%	9.36%	10.14%
Ameren Corporation	AEE	$1.76	$55.77	3.16%	3.25%	6.00%	6.10%	6.50%	6.20%	9.25%	9.45%	9.76%
American Electric Power Company, Inc.	AEP	$2.36	$68.76	3.43%	3.50%	4.00%	2.87%	5.40%	4.09%	6.35%	7.59%	8.92%
Duke Energy Corporation	DUK	$3.56	$83.33	4.27%	4.35%	4.50%	2.65%	4.00%	3.72%	6.98%	8.07%	8.87%
El Paso Electric Company	EE	$1.34	$51.32	2.61%	2.69%	5.00%	6.50%	7.20%	6.23%	7.68%	8.93%	9.91%
Hawaiian Electric Industries, Inc.	HE	$1.24	$33.18	3.74%	3.78%	1.50%	1.40%	4.00%	2.30%	5.16%	6.08%	7.81%
IDACORP, Inc.	IDA	$2.20	$84.87	2.59%	2.64%	3.50%	4.00%	4.50%	4.00%	6.14%	6.64%	7.15%
OGE Energy Corporation	OGE	$1.21	$35.23	3.43%	3.54%	6.00%	6.30%	5.30%	5.87%	8.83%	9.40%	9.84%
Pinnacle West Capital Corporation	PNW	$2.62	$84.90	3.09%	3.17%	5.50%	6.04%	5.20%	5.58%	8.37%	8.75%	9.22%
PNM Resources, Inc.	PNM	$0.97	$38.21	2.54%	2.63%	9.00%	7.35%	4.70%	7.02%	7.30%	9.64%	11.65%
Portland General Electric Company	POR	$1.36	$45.48	2.99%	3.06%	6.00%	4.90%	3.50%	4.80%	6.54%	7.86%	9.08%
PPL Corporation	PPL	$1.58	$37.87	4.17%	4.23%	NMF	0.04%	5.00%	2.52%	4.21%	6.75%	9.28%
Southern Company	SO	$2.32	$49.37	4.70%	4.79%	3.50%	3.22%	4.30%	3.67%	8.00%	8.46%	9.10%
MEAN				3.35%	3.43%	5.12%	4.52%	5.09%	4.85%	7.26%	8.27%	9.28%

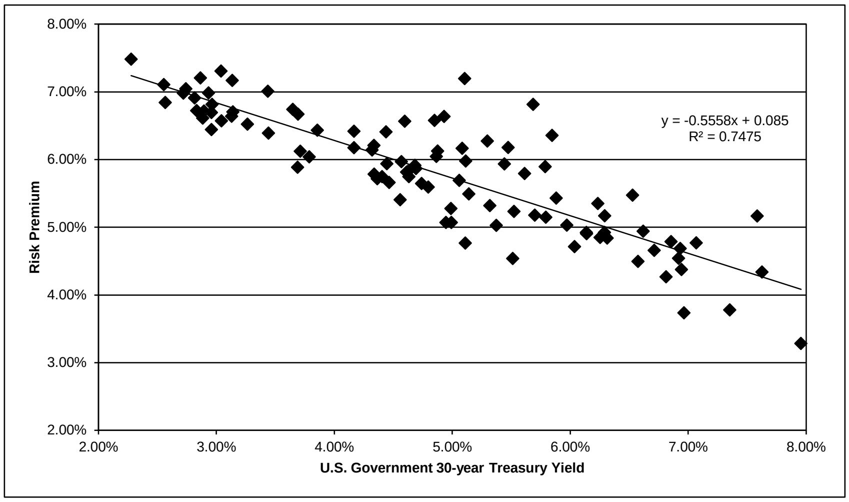
Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of September 29, 2017
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7])) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7])) + Maximum ([5], [6], [7])

TREASURY BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
	Average Authorized Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
1993.1	11.84%	7.07%	4.77%
1993.2	11.64%	6.86%	4.79%
1993.3	11.15%	6.31%	4.84%
1993.4	11.04%	6.14%	4.90%
1994.1	11.07%	6.57%	4.49%
1994.2	11.13%	7.35%	3.78%
1994.3	12.75%	7.58%	5.17%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.34%
1995.2	11.32%	6.94%	4.37%
1995.3	11.37%	6.71%	4.66%
1995.4	11.58%	6.23%	5.35%
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.96%	3.74%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.81%	4.27%
1997.2	11.62%	6.93%	4.68%
1997.3	12.00%	6.53%	5.47%
1997.4	11.06%	6.14%	4.92%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.47%	6.18%
1998.4	12.30%	5.10%	7.20%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.79%	5.15%
1999.3	10.75%	6.04%	4.71%
1999.4	11.10%	6.25%	4.85%
2000.1	11.21%	6.29%	4.92%
2000.2	11.00%	5.97%	5.03%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.44%	5.93%
2001.2	10.88%	5.70%	5.18%
2001.3	10.76%	5.52%	5.23%
2001.4	11.57%	5.30%	6.27%
2002.1	10.05%	5.51%	4.54%
2002.2	11.41%	5.61%	5.79%
2002.3	11.25%	5.08%	6.17%
2002.4	11.57%	4.93%	6.64%
2003.1	11.43%	4.85%	6.58%
2003.2	11.16%	4.60%	6.56%
2003.3	9.88%	5.11%	4.76%
2003.4	11.09%	5.11%	5.98%
2004.1	11.00%	4.88%	6.12%
2004.2	10.64%	5.32%	5.32%
2004.3	10.75%	5.06%	5.69%
2004.4	10.91%	4.86%	6.04%
2005.1	10.56%	4.69%	5.87%
2005.2	10.13%	4.47%	5.66%
2005.3	10.85%	4.44%	6.41%
2005.4	10.59%	4.68%	5.91%
2006.1	10.38%	4.63%	5.75%
2006.2	10.63%	5.14%	5.49%
2006.3	10.06%	4.99%	5.07%
2006.4	10.39%	4.74%	5.65%
2007.1	10.39%	4.80%	5.59%
2007.2	10.27%	4.99%	5.28%
2007.3	10.02%	4.95%	5.07%
2007.4	10.43%	4.61%	5.81%
2008.1	10.15%	4.41%	5.75%
2008.2	10.54%	4.57%	5.97%
2008.3	10.38%	4.44%	5.94%
2008.4	10.39%	3.65%	6.74%
2009.1	10.45%	3.44%	7.01%
2009.2	10.58%	4.17%	6.42%
2009.3	10.46%	4.32%	6.14%
2009.4	10.54%	4.34%	6.21%
2010.1	10.45%	4.62%	5.82%
2010.2	10.08%	4.36%	5.71%
2010.3	10.29%	3.86%	6.43%
2010.4	10.34%	4.17%	6.17%
2011.1	9.96%	4.56%	5.40%
2011.2	10.12%	4.34%	5.78%
2011.3	10.36%	3.69%	6.67%
2011.4	10.34%	3.04%	7.31%

TREASURY BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
	Average Authorized Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
2012.1	10.30%	3.14%	7.17%
2012.2	9.92%	2.93%	6.98%
2012.3	9.78%	2.74%	7.04%
2012.4	10.07%	2.86%	7.21%
2013.1	9.77%	3.13%	6.64%
2013.2	9.84%	3.14%	6.70%
2013.3	9.83%	3.71%	6.12%
2013.4	9.82%	3.79%	6.04%
2014.1	9.57%	3.69%	5.88%
2014.2	9.83%	3.44%	6.39%
2014.3	9.79%	3.26%	6.52%
2014.4	9.78%	2.96%	6.81%
2015.1	9.66%	2.55%	7.11%
2015.2	9.50%	2.88%	6.61%
2015.3	9.40%	2.96%	6.44%
2015.4	9.65%	2.96%	6.69%
2016.1	9.70%	2.72%	6.98%
2016.2	9.41%	2.57%	6.84%
2016.3	9.76%	2.28%	7.48%
2016.4	9.55%	2.83%	6.72%
2017.1	9.61%	3.04%	6.57%
2017.2	9.61%	2.90%	6.71%
2017.3	9.73%	2.82%	6.91%
AVERAGE	10.66%	4.86%	5.80%
MEDIAN	10.56%	4.86%	5.88%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.864557
R Square	0.747459
Adjusted R Square	0.744855
Standard Error	0.004537
Observations	99

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.005911	0.005911	287.095928	0.000000
Residual	97	0.001997	0.000021		
Total	98	0.007907			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0850	0.001659	51.26	0.000000	0.081752	0.088337	0.081752	0.088337
U.S. Govt. 30-year Treasury	(0.5558)	0.032803	(16.94)	0.000000	(0.620924)	(0.490713)	(0.620924)	(0.490713)

	[7]	[8]	[9]
	U.S. Govt. 30-year Treasury	Risk Premium	ROE
Current 30-Day Average [4]	2.77%	6.96%	9.74%
Blue Chip Consensus Forecast (Q4 2017-Q1 2019) [5]	3.30%	6.67%	9.97%
Blue Chip Consensus Forecast (2019-2023) [6]	4.30%	6.11%	10.41%
AVERAGE			10.04%

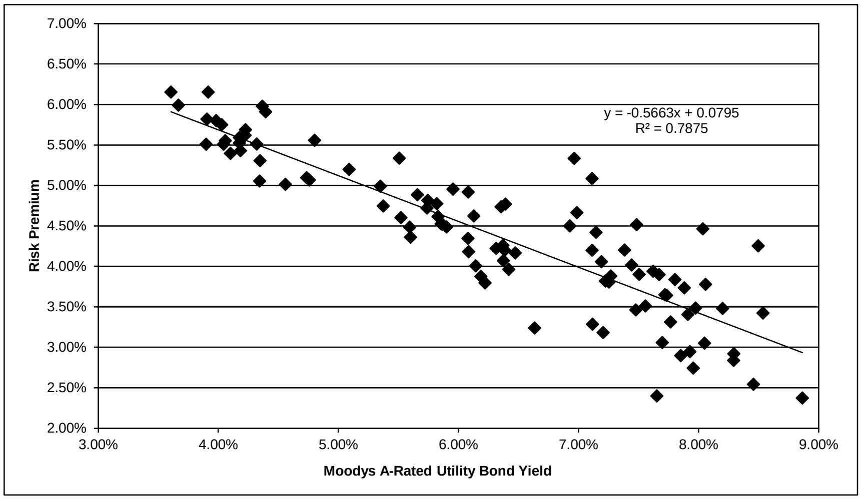
Notes:
[1] Source: Regulatory Research Associates, accessed October 5, 2017
[2] Source: Bloomberg Professional, quarterly bond yields are an average of the trading days in each quarter
[3] Equals Column [1] − Column [2]
[4] Source: Bloomberg Professional, equals 30-day average as of September 29, 2017
[5] Source: Blue Chip Financial Forecasts, Vol. 36, No. 10, October 1, 2017, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 36, No. 6, June 1, 2017, at 14
[7] *See notes [4], [5] & [6]*
[8] Equals 0.085044 + (-0.555818 x Column [7])
[9] Equals Column [7] + Column [8]

UTILITY BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
	Average Authorized Electric ROE	Moodys A-Rated Utility Bond	Risk Premium
1993.1	11.84%	8.06%	3.78%
1993.2	11.64%	7.80%	3.84%
1993.3	11.15%	7.27%	3.88%
1993.4	11.04%	7.22%	3.82%
1994.1	11.07%	7.56%	3.51%
1994.2	11.13%	8.29%	2.84%
1994.3	12.75%	8.50%	4.25%
1994.4	11.24%	8.86%	2.37%
1995.1	11.96%	8.54%	3.42%
1995.2	11.32%	7.91%	3.41%
1995.3	11.37%	7.72%	3.65%
1995.4	11.58%	7.38%	4.20%
1996.1	11.46%	7.44%	4.02%
1996.2	11.46%	7.97%	3.48%
1996.3	10.70%	7.96%	2.74%
1996.4	11.56%	7.62%	3.94%
1997.1	11.08%	7.77%	3.31%
1997.2	11.62%	7.88%	3.73%
1997.3	12.00%	7.48%	4.52%
1997.4	11.06%	7.25%	3.81%
1998.1	11.31%	7.11%	4.20%
1998.2	12.20%	7.11%	5.09%
1998.3	11.65%	6.99%	4.66%
1998.4	12.30%	6.97%	5.34%
1999.1	10.40%	7.12%	3.28%
1999.2	10.94%	7.48%	3.46%
1999.3	10.75%	7.85%	2.90%
1999.4	11.10%	8.05%	3.05%
2000.1	11.21%	8.29%	2.92%
2000.2	11.00%	8.46%	2.54%
2000.3	11.68%	8.20%	3.48%
2000.4	12.50%	8.04%	4.46%
2001.1	11.38%	7.73%	3.64%
2001.2	10.88%	7.93%	2.95%
2001.3	10.76%	7.70%	3.06%
2001.4	11.57%	7.67%	3.90%
2002.1	10.05%	7.65%	2.40%
2002.2	11.41%	7.50%	3.90%
2002.3	11.25%	7.19%	4.06%
2002.4	11.57%	7.15%	4.42%
2003.1	11.43%	6.93%	4.50%
2003.2	11.16%	6.39%	4.77%
2003.3	9.88%	6.64%	3.24%
2003.4	11.09%	6.35%	4.74%
2004.1	11.00%	6.08%	4.92%
2004.2	10.64%	6.47%	4.17%
2004.3	10.75%	6.13%	4.62%
2004.4	10.91%	5.95%	4.95%
2005.1	10.56%	5.75%	4.81%
2005.2	10.13%	5.52%	4.60%
2005.3	10.85%	5.51%	5.34%
2005.4	10.59%	5.82%	4.77%
2006.1	10.38%	5.86%	4.52%
2006.2	10.63%	6.37%	4.26%
2006.3	10.06%	6.19%	3.88%
2006.4	10.39%	5.87%	4.52%
2007.1	10.39%	5.90%	4.49%
2007.2	10.27%	6.08%	4.18%
2007.3	10.02%	6.22%	3.79%
2007.4	10.43%	6.08%	4.35%
2008.1	10.15%	6.14%	4.01%
2008.2	10.54%	6.31%	4.22%
2008.3	10.38%	6.42%	3.96%
2008.4	10.39%	7.21%	3.18%
2009.1	10.45%	6.37%	4.07%
2009.2	10.58%	6.39%	4.20%
2009.3	10.46%	5.74%	4.72%
2009.4	10.54%	5.66%	4.88%
2010.1	10.45%	5.83%	4.62%
2010.2	10.08%	5.59%	4.48%
2010.3	10.29%	5.09%	5.20%
2010.4	10.34%	5.35%	4.99%
2011.1	9.96%	5.60%	4.36%
2011.2	10.12%	5.37%	4.75%
2011.3	10.36%	4.80%	5.56%
2011.4	10.34%	4.37%	5.98%

UTILITY BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
	Average Authorized Electric ROE	Moodys A-Rated Utility Bond	Risk Premium
2012.1	10.30%	4.39%	5.91%
2012.2	9.92%	4.23%	5.69%
2012.3	9.78%	3.98%	5.80%
2012.4	10.07%	3.92%	6.15%
2013.1	9.77%	4.18%	5.59%
2013.2	9.84%	4.22%	5.62%
2013.3	9.83%	4.74%	5.10%
2013.4	9.82%	4.76%	5.07%
2014.1	9.57%	4.56%	5.01%
2014.2	9.83%	4.32%	5.51%
2014.3	9.79%	4.20%	5.59%
2014.4	9.78%	4.03%	5.75%
2015.1	9.66%	3.67%	5.99%
2015.2	9.50%	4.10%	5.39%
2015.3	9.40%	4.34%	5.06%
2015.4	9.65%	4.35%	5.30%
2016.1	9.70%	4.18%	5.52%
2016.2	9.41%	3.90%	5.51%
2016.3	9.76%	3.61%	6.15%
2016.4	9.55%	4.04%	5.51%
2017.1	9.61%	4.18%	5.43%
2017.2	9.61%	4.06%	5.55%
2017.3	9.73%	3.91%	5.82%
AVERAGE	10.66%	6.25%	4.41%
MEDIAN	10.56%	6.35%	4.46%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.887394
R Square	0.787469
Adjusted R Square	0.785278
Standard Error	0.004331
Observations	99

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.006740	0.006740	359.403051	0.000000
Residual	97	0.001819	0.000019		
Total	98	0.008560			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0795	0.001918	41.47	0.000000	0.075725	0.083336	0.075725	0.083336
Moodys A-Rated Utility Bond	(0.5663)	0.029873	(18.96)	0.000000	(0.625617)	(0.507038)	(0.625617)	(0.507038)

	[7]	[8]	[9]
	Moodys A-Rated Utility Bond	Risk Premium	ROE
Current 30-Day Average [4]	3.86%	5.77%	9.62%
Near-Term Consensus Forecast (Q4 2017-Q1 2019) [5]	4.56%	5.37%	9.93%
Long-Term Consensus Forecast (2019-2023) [6]	5.56%	4.80%	10.36%
AVERAGE			9.97%

Notes:

[1] Source: Regulatory Research Associates, accessed October 5, 2017
[2] Source: Bloomberg Professional, quarterly bond yields are an average of the trading days in each quarter
[3] Equals Column [1] − Column [2]
[4] Source: Bloomberg Professional, equals 30-day average as of September 29, 2017
[5] Equals Blue Chip Financial Forecasts near-term 30-year Treasury bond yield (Q4 2017-Q1 2019 Average: 3.30%) plus average daily spread between Treasury and utility bond yields from January 1, 2015 through September 29, 2017 (1.26%)
[6] Equals Blue Chip Financial Forecasts long-term 30-year Treasury bond yield (2019 - 2023 Forecast: 4.30%) plus average daily spread between Treasury and utility bond yields from January 1, 2015 through September, 2017 (1.26%)
[7] *See notes [4], [5] & [6]*
[8] Equals 0.079530 + (-0.566328 x Column [7])
[9] Equals Column [7] + Column [8]

BETA
AS OF SEPTEMBER 29, 2017

		[1]	[2]
		Bloomberg	Value Line
ALLETE, Inc.	ALE	0.686	0.750
Alliant Energy Corporation	LNT	0.470	0.700
Ameren Corporation	AEE	0.483	0.650
American Electric Power Company, Inc.	AEP	0.496	0.650
Duke Energy Corporation	DUK	0.479	0.600
El Paso Electric Company	EE	0.728	0.750
Hawaiian Electric Industries, Inc.	HE	0.479	0.700
IDACORP, Inc.	IDA	0.707	0.700
OGE Energy Corporation	OGE	0.636	0.950
Pinnacle West Capital Corporation	PNW	0.554	0.650
PNM Resources, Inc.	PNM	0.589	0.750
Portland General Electric Company	POR	0.540	0.700
PPL Corporation	PPL	0.548	0.700
Southern Company	SO	0.510	0.550
Average		0.565	0.700

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield		1.98%	
[2] Estimated Weighted Average Long-Term Growth Rate		11.46%	
[3] S&P 500 Estimated Required Market Return		13.55%	
[4] Risk-Free Rate	2.77%	3.30%	4.30%
[5] Implied Market Risk Premium	10.78%	10.25%	9.25%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[6] Weight In Index	[7] Estimated Dividend Yield	[8] Cap-Weighted Dividend Yield	[9] Long-Term Growth Estimate	[10] Cap. Weighted Long-Term Growth
LyondellBasell Industries NV	LYB	0.18%	3.63%	0.01%	6.50%	0.01%
American Express Co	AXP	0.36%	1.55%	0.01%	9.70%	0.03%
Verizon Communications Inc	VZ	0.90%	4.77%	0.04%	1.92%	0.02%
Broadcom Ltd	AVGO	0.44%	1.68%	0.01%	15.32%	0.07%
Boeing Co/The	BA	0.67%	2.23%	0.01%	15.20%	0.10%
Caterpillar Inc	CAT	0.33%	2.50%	0.01%	10.00%	0.03%
JPMorgan Chase & Co	JPM	1.50%	2.35%	0.04%	3.00%	0.05%
Chevron Corp	CVX	0.99%	3.68%	0.04%	42.57%	0.42%
Coca-Cola Co/The	KO	0.86%	3.29%	0.03%	5.61%	0.05%
AbbVie Inc	ABBV	0.63%	2.88%	0.02%	8.60%	0.05%
Walt Disney Co/The	DIS	0.68%	1.58%	0.01%	7.19%	0.05%
Extra Space Storage Inc	EXR	0.04%	3.90%	0.00%	6.57%	0.00%
Exxon Mobil Corp	XOM	1.55%	3.76%	0.06%	19.49%	0.30%
Phillips 66	PSX	0.21%	3.06%	0.01%	-3.74%	-0.01%
General Electric Co	GE	0.94%	3.97%	0.04%	11.23%	0.11%
HP Inc	HPQ	0.15%	2.66%	0.00%	4.09%	0.01%
Home Depot Inc/The	HD	0.86%	2.18%	0.02%	13.69%	0.12%
International Business Machines Corp	IBM	0.60%	4.14%	0.02%	2.38%	0.01%
Concho Resources Inc	CXO	0.09%	n/a	n/a	20.00%	0.02%
Johnson & Johnson	JNJ	1.56%	2.58%	0.04%	6.03%	0.09%
McDonald's Corp	MCD	0.57%	2.58%	0.01%	10.09%	0.06%
Merck & Co Inc	MRK	0.78%	2.94%	0.02%	6.07%	0.05%
3M Co	MMM	0.56%	2.24%	0.01%	8.80%	0.05%
American Water Works Co Inc	AWK	0.06%	2.05%	0.00%	7.95%	0.01%
Bank of America Corp	BAC	1.19%	1.89%	0.02%	10.47%	0.13%
CSRA Inc	CSRA	0.02%	1.24%	0.00%	7.55%	0.00%
Brighthouse Financial Inc	BHF	0.03%	n/a	n/a	8.00%	0.00%
Baker Hughes a GE Co	BHGE	0.07%	1.86%	0.00%	6.50%	0.00%
Pfizer Inc	PFE	0.95%	3.59%	0.03%	8.43%	0.08%
Procter & Gamble Co/The	PG	1.04%	3.03%	0.03%	7.18%	0.07%
AT&T Inc	T	1.07%	5.00%	0.05%	5.25%	0.06%
Travelers Cos Inc/The	TRV	0.15%	2.35%	0.00%	11.58%	0.02%
United Technologies Corp	UTX	0.41%	2.41%	0.01%	8.72%	0.04%
Analog Devices Inc	ADI	0.14%	2.09%	0.00%	11.55%	0.02%
Wal-Mart Stores Inc	WMT	1.04%	2.61%	0.03%	5.12%	0.05%
Cisco Systems Inc	CSCO	0.74%	3.45%	0.03%	6.43%	0.05%
Intel Corp	INTC	0.80%	2.86%	0.02%	8.14%	0.07%
General Motors Co	GM	0.26%	3.76%	0.01%	9.04%	0.02%
Microsoft Corp	MSFT	2.56%	2.26%	0.06%	10.54%	0.27%
Dollar General Corp	DG	0.10%	1.28%	0.00%	8.55%	0.01%
Kinder Morgan Inc/DE	KMI	0.19%	2.61%	0.00%	20.00%	0.04%
Citigroup Inc	C	0.89%	1.76%	0.02%	12.97%	0.11%
American International Group Inc	AIG	0.25%	2.09%	0.01%	11.00%	0.03%
Honeywell International Inc	HON	0.48%	2.10%	0.01%	9.95%	0.05%
Altria Group Inc	MO	0.54%	4.16%	0.02%	0.61%	0.00%
HCA Healthcare Inc	HCA	0.13%	n/a	n/a	12.07%	0.02%
Under Armour Inc	UAA	0.01%	n/a	n/a	13.17%	0.00%
International Paper Co	IP	0.10%	3.26%	0.00%	7.23%	0.01%
Hewlett Packard Enterprise Co	HPE	0.11%	1.77%	0.00%	-3.56%	0.00%
Abbott Laboratories	ABT	0.41%	1.99%	0.01%	11.77%	0.05%
Aflac Inc	AFL	0.14%	2.11%	0.00%	2.85%	0.00%
Air Products & Chemicals Inc	APD	0.15%	2.51%	0.00%	9.29%	0.01%
Royal Caribbean Cruises Ltd	RCL	0.11%	2.02%	0.00%	19.10%	0.02%
American Electric Power Co Inc	AEP	0.15%	3.36%	0.01%	5.00%	0.01%
Hess Corp	HES	0.07%	2.13%	0.00%	-14.74%	-0.01%
Anadarko Petroleum Corp	APC	0.12%	0.41%	0.00%	-10.30%	-0.01%
Aon PLC	AON	0.17%	0.99%	0.00%	11.86%	0.02%
Apache Corp	APA	0.08%	2.18%	0.00%	-20.64%	-0.02%
Archer-Daniels-Midland Co	ADM	0.11%	3.01%	0.00%	9.80%	0.01%
Automatic Data Processing Inc	ADP	0.22%	2.09%	0.00%	11.48%	0.02%
Verisk Analytics Inc	VRSK	0.06%	n/a	n/a	7.96%	0.00%
AutoZone Inc	AZO	0.07%	n/a	n/a	13.07%	0.01%
Avery Dennison Corp	AVY	0.04%	1.83%	0.00%	7.65%	0.00%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield		1.98%	
[2] Estimated Weighted Average Long-Term Growth Rate		11.46%	
[3] S&P 500 Estimated Required Market Return		13.55%	
[4] Risk-Free Rate	2.77%	3.30%	4.30%
[5] Implied Market Risk Premium	10.78%	10.25%	9.25%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[6] Weight In Index	[7] Estimated Dividend Yield	[8] Cap-Weighted Dividend Yield	[9] Long-Term Growth Estimate	[10] Cap. Weighted Long-Term Growth
Ball Corp	BLL	0.06%	0.97%	0.00%	7.23%	0.00%
Bank of New York Mellon Corp/The	BK	0.24%	1.81%	0.00%	13.24%	0.03%
CR Bard Inc	BCR	0.10%	0.32%	0.00%	11.00%	0.01%
Baxter International Inc	BAX	0.15%	1.02%	0.00%	13.56%	0.02%
Becton Dickinson and Co	BDX	0.20%	1.49%	0.00%	12.53%	0.02%
Berkshire Hathaway Inc	BRK/B	1.09%	n/a	n/a	n/a	n/a
Best Buy Co Inc	BBY	0.08%	2.39%	0.00%	12.68%	0.01%
H&R Block Inc	HRB	0.02%	3.63%	0.00%	11.00%	0.00%
Boston Scientific Corp	BSX	0.18%	n/a	n/a	10.33%	0.02%
Bristol-Myers Squibb Co	BMY	0.47%	2.45%	0.01%	8.00%	0.04%
Fortune Brands Home & Security Inc	FBHS	0.05%	1.07%	0.00%	12.12%	0.01%
Brown-Forman Corp	BF/B	0.05%	1.34%	0.00%	9.72%	0.01%
Cabot Oil & Gas Corp	COG	0.06%	0.75%	0.00%	31.95%	0.02%
Campbell Soup Co	CPB	0.06%	2.99%	0.00%	4.46%	0.00%
Kansas City Southern	KSU	0.05%	1.33%	0.00%	14.00%	0.01%
Advanced Micro Devices Inc	AMD	0.05%	n/a	n/a	5.00%	0.00%
Hilton Worldwide Holdings Inc	HLT	0.10%	0.86%	0.00%	15.76%	0.02%
Carnival Corp	CCL	0.15%	2.48%	0.00%	13.28%	0.02%
Qorvo Inc	QRVO	0.04%	n/a	n/a	13.18%	0.01%
CenturyLink Inc	CTL	0.05%	11.43%	0.01%	-2.86%	0.00%
Cigna Corp	CI	0.21%	0.02%	0.00%	12.91%	0.03%
UDR Inc	UDR	0.05%	3.26%	0.00%	6.13%	0.00%
Clorox Co/The	CLX	0.08%	2.55%	0.00%	6.72%	0.01%
CMS Energy Corp	CMS	0.06%	2.87%	0.00%	5.00%	0.00%
Colgate-Palmolive Co	CL	0.29%	2.20%	0.01%	9.47%	0.03%
Comerica Inc	CMA	0.06%	1.57%	0.00%	8.00%	0.00%
CA Inc	CA	0.06%	3.06%	0.00%	2.97%	0.00%
Conagra Brands Inc	CAG	0.06%	2.52%	0.00%	7.00%	0.00%
Consolidated Edison Inc	ED	0.11%	3.42%	0.00%	n/a	n/a
SL Green Realty Corp	SLG	0.04%	3.06%	0.00%	0.64%	0.00%
Corning Inc	GLW	0.12%	2.07%	0.00%	8.58%	0.01%
Cummins Inc	CMI	0.13%	2.57%	0.00%	10.23%	0.01%
Danaher Corp	DHR	0.27%	0.65%	0.00%	7.57%	0.02%
Target Corp	TGT	0.14%	4.20%	0.01%	-0.78%	0.00%
Deere & Co	DE	0.18%	1.91%	0.00%	4.50%	0.01%
Dominion Energy Inc	D	0.22%	3.93%	0.01%	5.60%	0.01%
Dover Corp	DOV	0.06%	2.06%	0.00%	15.47%	0.01%
CBOE Holdings Inc	CBOE	0.05%	1.00%	0.00%	22.39%	0.01%
Duke Energy Corp	DUK	0.26%	4.24%	0.01%	2.00%	0.01%
Eaton Corp PLC	ETN	0.15%	3.13%	0.00%	10.22%	0.02%
Ecolab Inc	ECL	0.17%	1.15%	0.00%	12.86%	0.02%
PerkinElmer Inc	PKI	0.03%	0.41%	0.00%	10.42%	0.00%
Emerson Electric Co	EMR	0.18%	3.06%	0.01%	7.45%	0.01%
EOG Resources Inc	EOG	0.25%	0.69%	0.00%	-18.26%	-0.05%
Entergy Corp	ETR	0.06%	4.56%	0.00%	-3.83%	0.00%
Equifax Inc	EFX	0.06%	1.47%	0.00%	11.03%	0.01%
EQT Corp	EQT	0.05%	0.18%	0.00%	15.00%	0.01%
Quintiles IMS Holdings Inc	Q	0.09%	n/a	n/a	14.33%	0.01%
XL Group Ltd	XL	0.05%	2.23%	0.00%	9.00%	0.00%
Gartner Inc	IT	0.05%	n/a	n/a	17.50%	0.01%
FedEx Corp	FDX	0.27%	0.89%	0.00%	12.50%	0.03%
Macy's Inc	M	0.03%	6.92%	0.00%	-0.48%	0.00%
FMC Corp	FMC	0.05%	0.74%	0.00%	12.60%	0.01%
Ford Motor Co	F	0.21%	5.01%	0.01%	-2.07%	0.00%
NextEra Energy Inc	NEE	0.31%	2.68%	0.01%	6.67%	0.02%
Franklin Resources Inc	BEN	0.11%	1.80%	0.00%	10.00%	0.01%
Freeport-McMoRan Inc	FCX	0.09%	n/a	n/a	24.46%	0.02%
Gap Inc/The	GPS	0.05%	3.12%	0.00%	7.00%	0.00%
General Dynamics Corp	GD	0.28%	1.63%	0.00%	8.51%	0.02%
General Mills Inc	GIS	0.13%	3.79%	0.00%	9.57%	0.01%
Genuine Parts Co	GPC	0.06%	2.82%	0.00%	8.92%	0.01%
WW Grainger Inc	GWW	0.05%	2.85%	0.00%	9.55%	0.00%
Halliburton Co	HAL	0.18%	1.56%	0.00%	74.00%	0.13%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield		1.98%	
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STANDARD AND POOR'S 500 INDEX

Name	Ticker	[6] Weight In Index	[7] Estimated Dividend Yield	[8] Cap-Weighted Dividend Yield	[9] Long-Term Growth Estimate	[10] Cap. Weighted Long-Term Growth
Harley-Davidson Inc	HOG	0.04%	3.03%	0.00%	7.85%	0.00%
Harris Corp	HRS	0.07%	1.73%	0.00%	n/a	n/a
HCP Inc	HCP	0.06%	5.32%	0.00%	3.11%	0.00%
Helmerich & Payne Inc	HP	0.03%	5.37%	0.00%	n/a	n/a
Fortive Corp	FTV	0.11%	0.40%	0.00%	9.37%	0.01%
Hershey Co/The	HSY	0.07%	2.40%	0.00%	9.53%	0.01%
Synchrony Financial	SYF	0.11%	1.93%	0.00%	8.09%	0.01%
Hormel Foods Corp	HRL	0.08%	2.12%	0.00%	6.15%	0.00%
Arthur J Gallagher & Co	AJG	0.05%	2.53%	0.00%	10.83%	0.01%
Mondelez International Inc	MDLZ	0.27%	2.16%	0.01%	11.64%	0.03%
CenterPoint Energy Inc	CNP	0.06%	3.66%	0.00%	6.00%	0.00%
Humana Inc	HUM	0.16%	0.66%	0.00%	12.93%	0.02%
Willis Towers Watson PLC	WLTW	0.09%	1.37%	0.00%	10.00%	0.01%
Illinois Tool Works Inc	ITW	0.23%	2.11%	0.00%	9.20%	0.02%
Ingersoll-Rand PLC	IR	0.10%	2.02%	0.00%	10.71%	0.01%
Foot Locker Inc	FL	0.02%	3.52%	0.00%	3.40%	0.00%
Interpublic Group of Cos Inc/The	IPG	0.04%	3.46%	0.00%	8.64%	0.00%
International Flavors & Fragrances Inc	IFF	0.05%	1.93%	0.00%	4.00%	0.00%
Jacobs Engineering Group Inc	JEC	0.03%	1.03%	0.00%	8.73%	0.00%
Hanesbrands Inc	HBI	0.04%	2.44%	0.00%	10.45%	0.00%
Kellogg Co	K	0.10%	3.46%	0.00%	6.23%	0.01%
Perrigo Co PLC	PRGO	0.05%	0.76%	0.00%	5.97%	0.00%
Kimberly-Clark Corp	KMB	0.19%	3.30%	0.01%	6.22%	0.01%
Kimco Realty Corp	KIM	0.04%	5.52%	0.00%	19.96%	0.01%
Kohl's Corp	KSS	0.03%	4.82%	0.00%	5.45%	0.00%
Oracle Corp	ORCL	0.90%	1.57%	0.01%	8.77%	0.08%
Kroger Co/The	KR	0.08%	2.49%	0.00%	5.57%	0.00%
Leggett & Platt Inc	LEG	0.03%	3.02%	0.00%	19.00%	0.01%
Lennar Corp	LEN	0.05%	0.30%	0.00%	11.29%	0.01%
Leucadia National Corp	LUK	0.04%	1.58%	0.00%	18.00%	0.01%
Eli Lilly & Co	LLY	0.42%	2.43%	0.01%	8.50%	0.04%
L Brands Inc	LB	0.05%	5.77%	0.00%	6.81%	0.00%
Charter Communications Inc	CHTR	0.42%	n/a	n/a	23.96%	0.10%
Lincoln National Corp	LNC	0.07%	1.58%	0.00%	9.25%	0.01%
Loews Corp	L	0.07%	0.52%	0.00%	n/a	n/a
Lowe's Cos Inc	LOW	0.30%	2.05%	0.01%	14.38%	0.04%
Host Hotels & Resorts Inc	HST	0.06%	4.33%	0.00%	4.10%	0.00%
Marsh & McLennan Cos Inc	MMC	0.19%	1.79%	0.00%	12.86%	0.02%
Masco Corp	MAS	0.06%	1.08%	0.00%	14.33%	0.01%
Mattel Inc	MAT	0.02%	3.88%	0.00%	11.30%	0.00%
S&P Global Inc	SPGI	0.18%	1.05%	0.00%	10.00%	0.02%
Medtronic PLC	MDT	0.47%	2.37%	0.01%	6.43%	0.03%
CVS Health Corp	CVS	0.37%	2.46%	0.01%	13.33%	0.05%
DowDuPont Inc	DWDP	0.72%	2.66%	0.02%	7.83%	0.06%
Micron Technology Inc	MU	0.20%	n/a	n/a	0.83%	0.00%
Motorola Solutions Inc	MSI	0.06%	2.22%	0.00%	4.10%	0.00%
Mylan NV	MYL	0.08%	n/a	n/a	3.20%	0.00%
Laboratory Corp of America Holdings	LH	0.07%	n/a	n/a	11.35%	0.01%
Newell Brands Inc	NWL	0.09%	2.16%	0.00%	11.32%	0.01%
Newmont Mining Corp	NEM	0.09%	0.80%	0.00%	-11.65%	-0.01%
Twenty-First Century Fox Inc	FOXA	0.12%	1.36%	0.00%	9.23%	0.01%
NIKE Inc	NKE	0.30%	1.39%	0.00%	8.50%	0.03%
NiSource Inc	NI	0.04%	2.74%	0.00%	6.10%	0.00%
Noble Energy Inc	NBL	0.06%	1.41%	0.00%	3.72%	0.00%
Norfolk Southern Corp	NSC	0.17%	1.85%	0.00%	13.57%	0.02%
Eversource Energy	ES	0.09%	3.14%	0.00%	6.10%	0.01%
Northrop Grumman Corp	NOC	0.22%	1.39%	0.00%	7.67%	0.02%
Wells Fargo & Co	WFC	1.22%	2.83%	0.03%	11.46%	0.14%
Nucor Corp	NUE	0.08%	2.69%	0.00%	12.00%	0.01%
PVH Corp	PVH	0.04%	0.12%	0.00%	10.96%	0.00%
Occidental Petroleum Corp	OXY	0.22%	4.80%	0.01%	-3.39%	-0.01%
Omnicom Group Inc	OMC	0.08%	2.97%	0.00%	4.95%	0.00%
ONEOK Inc	OKE	0.09%	5.38%	0.01%	13.25%	0.01%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield		1.98%	
[2] Estimated Weighted Average Long-Term Growth Rate		11.46%	
[3] S&P 500 Estimated Required Market Return		13.55%	
[4] Risk-Free Rate	2.77%	3.30%	4.30%
[5] Implied Market Risk Premium	10.78%	10.25%	9.25%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[6] Weight In Index	[7] Estimated Dividend Yield	[8] Cap-Weighted Dividend Yield	[9] Long-Term Growth Estimate	[10] Cap. Weighted Long-Term Growth
Raymond James Financial Inc	RJF	0.05%	1.04%	0.00%	15.45%	0.01%
PG&E Corp	PCG	0.16%	3.11%	0.00%	n/a	n/a
Parker-Hannifin Corp	PH	0.10%	1.51%	0.00%	11.88%	0.01%
PPL Corp	PPL	0.12%	4.16%	0.00%	n/a	n/a
PepsiCo Inc	PEP	0.71%	2.89%	0.02%	6.06%	0.04%
Exelon Corp	EXC	0.16%	3.48%	0.01%	3.57%	0.01%
ConocoPhillips	COP	0.27%	2.12%	0.01%	7.00%	0.02%
PulteGroup Inc	PHM	0.04%	1.32%	0.00%	18.40%	0.01%
Pinnacle West Capital Corp	PNW	0.04%	3.10%	0.00%	5.50%	0.00%
PNC Financial Services Group Inc/The	PNC	0.29%	2.23%	0.01%	10.12%	0.03%
PPG Industries Inc	PPG	0.12%	1.66%	0.00%	8.09%	0.01%
Praxair Inc	PX	0.18%	2.25%	0.00%	10.35%	0.02%
Progressive Corp/The	PGR	0.13%	1.41%	0.00%	11.83%	0.01%
Public Service Enterprise Group Inc	PEG	0.10%	3.72%	0.00%	2.90%	0.00%
Raytheon Co	RTN	0.24%	1.71%	0.00%	8.41%	0.02%
Robert Half International Inc	RHI	0.03%	1.91%	0.00%	8.30%	0.00%
SCANA Corp	SCG	0.03%	5.05%	0.00%	3.25%	0.00%
Edison International	EIX	0.11%	2.81%	0.00%	6.23%	0.01%
Schlumberger Ltd	SLB	0.43%	2.87%	0.01%	41.71%	0.18%
Charles Schwab Corp/The	SCHW	0.26%	0.73%	0.00%	19.46%	0.05%
Sherwin-Williams Co/The	SHW	0.15%	0.95%	0.00%	10.99%	0.02%
JM Smucker Co/The	SJM	0.05%	2.97%	0.00%	3.96%	0.00%
Snap-on Inc	SNA	0.04%	1.91%	0.00%	10.85%	0.00%
AMETEK Inc	AME	0.07%	0.55%	0.00%	11.62%	0.01%
Southern Co/The	SO	0.22%	4.72%	0.01%	2.00%	0.00%
BB&T Corp	BBT	0.17%	2.81%	0.00%	9.75%	0.02%
Southwest Airlines Co	LUV	0.15%	0.89%	0.00%	6.43%	0.01%
Stanley Black & Decker Inc	SWK	0.10%	1.67%	0.00%	11.00%	0.01%
Public Storage	PSA	0.17%	3.74%	0.01%	5.45%	0.01%
SunTrust Banks Inc	STI	0.13%	2.68%	0.00%	9.42%	0.01%
Sysco Corp	SYY	0.13%	2.45%	0.00%	10.04%	0.01%
Andeavor	ANDV	0.07%	2.29%	0.00%	18.94%	0.01%
Texas Instruments Inc	TXN	0.40%	2.77%	0.01%	10.53%	0.04%
Textron Inc	TXT	0.06%	0.15%	0.00%	8.78%	0.01%
Thermo Fisher Scientific Inc	TMO	0.34%	0.32%	0.00%	13.00%	0.04%
Tiffany & Co	TIF	0.05%	2.18%	0.00%	10.10%	0.01%
TJX Cos Inc/The	TJX	0.21%	1.70%	0.00%	10.65%	0.02%
Torchmark Corp	TMK	0.04%	0.75%	0.00%	8.00%	0.00%
Total System Services Inc	TSS	0.05%	0.79%	0.00%	11.14%	0.01%
Johnson Controls International plc	JCI	0.17%	2.48%	0.00%	8.47%	0.01%
Ulta Beauty Inc	ULTA	0.06%	n/a	n/a	21.60%	0.01%
Union Pacific Corp	UNP	0.41%	2.09%	0.01%	11.63%	0.05%
UnitedHealth Group Inc	UNH	0.85%	1.53%	0.01%	12.15%	0.10%
Unum Group	UNM	0.05%	1.80%	0.00%	5.00%	0.00%
Marathon Oil Corp	MRO	0.05%	1.47%	0.00%	5.00%	0.00%
Varian Medical Systems Inc	VAR	0.04%	n/a	n/a	7.20%	0.00%
Ventas Inc	VTR	0.10%	4.76%	0.00%	3.03%	0.00%
VF Corp	VFC	0.11%	2.64%	0.00%	7.96%	0.01%
Vornado Realty Trust	VNO	0.07%	3.12%	0.00%	-0.83%	0.00%
Vulcan Materials Co	VMC	0.07%	0.84%	0.00%	21.82%	0.02%
Weyerhaeuser Co	WY	0.11%	3.64%	0.00%	7.40%	0.01%
Whirlpool Corp	WHR	0.06%	2.39%	0.00%	14.19%	0.01%
Williams Cos Inc/The	WMB	0.11%	4.00%	0.00%	n/a	n/a
WEC Energy Group Inc	WEC	0.09%	3.31%	0.00%	5.55%	0.00%
Xerox Corp	XRX	0.04%	3.00%	0.00%	2.90%	0.00%
Adobe Systems Inc	ADBE	0.33%	n/a	n/a	19.82%	0.07%
AES Corp/VA	AES	0.03%	4.36%	0.00%	8.00%	0.00%
Amgen Inc	AMGN	0.61%	2.47%	0.01%	4.67%	0.03%
Apple Inc	AAPL	3.56%	1.64%	0.06%	10.98%	0.39%
Autodesk Inc	ADSK	0.11%	n/a	n/a	26.00%	0.03%
Cintas Corp	CTAS	0.07%	0.92%	0.00%	11.58%	0.01%
Comcast Corp	CMCSA	0.81%	1.64%	0.01%	9.13%	0.07%
Molson Coors Brewing Co	TAP	0.07%	2.01%	0.00%	7.32%	0.01%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

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[3] S&P 500 Estimated Required Market Return		13.55%	
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STANDARD AND POOR'S 500 INDEX

Name	Ticker	[6] Weight In Index	[7] Estimated Dividend Yield	[8] Cap-Weighted Dividend Yield	[9] Long-Term Growth Estimate	[10] Cap. Weighted Long-Term Growth
KLA-Tencor Corp	KLAC	0.07%	2.23%	0.00%	7.90%	0.01%
Marriott International Inc/MD	MAR	0.18%	1.20%	0.00%	14.94%	0.03%
McCormick & Co Inc/MD	MKC	0.05%	1.83%	0.00%	9.60%	0.01%
Nordstrom Inc	JWN	0.04%	3.14%	0.00%	6.00%	0.00%
PACCAR Inc	PCAR	0.11%	1.38%	0.00%	6.73%	0.01%
Costco Wholesale Corp	COST	0.32%	1.22%	0.00%	10.18%	0.03%
Stryker Corp	SYK	0.24%	1.20%	0.00%	9.23%	0.02%
Tyson Foods Inc	TSN	0.09%	1.28%	0.00%	8.60%	0.01%
Applied Materials Inc	AMAT	0.25%	0.77%	0.00%	16.71%	0.04%
Time Warner Inc	TWX	0.36%	1.57%	0.01%	8.30%	0.03%
American Airlines Group Inc	AAL	0.10%	0.84%	0.00%	-3.18%	0.00%
Cardinal Health Inc	CAH	0.09%	2.76%	0.00%	12.37%	0.01%
Celgene Corp	CELG	0.51%	n/a	n/a	19.46%	0.10%
Cerner Corp	CERN	0.11%	n/a	n/a	12.00%	0.01%
Cincinnati Financial Corp	CINF	0.06%	2.61%	0.00%	n/a	n/a
DR Horton Inc	DHI	0.07%	1.00%	0.00%	12.66%	0.01%
Flowserve Corp	FLS	0.02%	1.78%	0.00%	12.68%	0.00%
Electronic Arts Inc	EA	0.16%	n/a	n/a	14.17%	0.02%
Express Scripts Holding Co	ESRX	0.16%	n/a	n/a	13.28%	0.02%
Expeditors International of Washington Inc	EXPD	0.05%	1.40%	0.00%	8.40%	0.00%
Fastenal Co	FAST	0.06%	2.81%	0.00%	15.40%	0.01%
M&T Bank Corp	MTB	0.11%	1.86%	0.00%	10.19%	0.01%
Fiserv Inc	FISV	0.12%	n/a	n/a	10.80%	0.01%
Fifth Third Bancorp	FITB	0.09%	2.29%	0.00%	4.20%	0.00%
Gilead Sciences Inc	GILD	0.47%	2.57%	0.01%	-7.44%	-0.04%
Hasbro Inc	HAS	0.05%	2.33%	0.00%	9.70%	0.01%
Huntington Bancshares Inc/OH	HBAN	0.07%	2.29%	0.00%	10.71%	0.01%
Welltower Inc	HCN	0.12%	4.95%	0.01%	2.61%	0.00%
Biogen Inc	BIIB	0.30%	n/a	n/a	6.48%	0.02%
Range Resources Corp	RRC	0.02%	0.41%	0.00%	-19.59%	0.00%
Northern Trust Corp	NTRS	0.09%	1.83%	0.00%	12.14%	0.01%
Packaging Corp of America	PKG	0.05%	2.20%	0.00%	8.25%	0.00%
Paychex Inc	PAYX	0.10%	3.34%	0.00%	7.70%	0.01%
People's United Financial Inc	PBCT	0.03%	3.80%	0.00%	2.00%	0.00%
Patterson Cos Inc	PDCO	0.02%	2.69%	0.00%	10.63%	0.00%
QUALCOMM Inc	QCOM	0.34%	4.40%	0.02%	8.75%	0.03%
Roper Technologies Inc	ROP	0.11%	0.58%	0.00%	12.93%	0.01%
Ross Stores Inc	ROST	0.11%	0.99%	0.00%	13.60%	0.02%
IDEXX Laboratories Inc	IDXX	0.06%	n/a	n/a	10.81%	0.01%
Starbucks Corp	SBUX	0.35%	1.86%	0.01%	16.52%	0.06%
KeyCorp	KEY	0.09%	2.02%	0.00%	10.90%	0.01%
State Street Corp	STT	0.16%	1.76%	0.00%	11.80%	0.02%
US Bancorp	USB	0.40%	2.24%	0.01%	12.13%	0.05%
AO Smith Corp	AOS	0.04%	0.94%	0.00%	15.00%	0.01%
Symantec Corp	SYMC	0.09%	0.91%	0.00%	13.14%	0.01%
T Rowe Price Group Inc	TROW	0.10%	2.52%	0.00%	12.85%	0.01%
Waste Management Inc	WM	0.15%	2.17%	0.00%	10.22%	0.02%
CBS Corp	CBS	0.09%	1.24%	0.00%	13.37%	0.01%
Allergan PLC	AGN	0.31%	1.37%	0.00%	12.33%	0.04%
Constellation Brands Inc	STZ	0.15%	1.04%	0.00%	16.36%	0.03%
Xilinx Inc	XLNX	0.08%	1.98%	0.00%	8.37%	0.01%
DENTSPLY SIRONA Inc	XRAY	0.06%	0.59%	0.00%	9.80%	0.01%
Zions Bancorporation	ZION	0.04%	1.02%	0.00%	9.00%	0.00%
Alaska Air Group Inc	ALK	0.04%	1.57%	0.00%	6.33%	0.00%
Invesco Ltd	IVZ	0.06%	3.31%	0.00%	12.29%	0.01%
Intuit Inc	INTU	0.16%	1.10%	0.00%	14.88%	0.02%
Morgan Stanley	MS	0.40%	2.08%	0.01%	16.72%	0.07%
Microchip Technology Inc	MCHP	0.09%	1.61%	0.00%	17.06%	0.02%
Chubb Ltd	CB	0.30%	1.99%	0.01%	10.60%	0.03%
Hologic Inc	HOLX	0.05%	n/a	n/a	9.18%	0.00%
Chesapeake Energy Corp	CHK	0.02%	n/a	n/a	-13.02%	0.00%
Citizens Financial Group Inc	CFG	0.08%	1.90%	0.00%	21.44%	0.02%
O'Reilly Automotive Inc	ORLY	0.08%	n/a	n/a	15.32%	0.01%

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STANDARD AND POOR'S 500 INDEX

		[6]	[7]	[8]	[9]	[10]
Name	Ticker	Weight In Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Long-Term Growth Estimate	Cap. Weighted Long-Term Growth
Allstate Corp/The	ALL	0.15%	1.61%	0.00%	16.27%	0.02%
FLIR Systems Inc	FLIR	0.02%	1.54%	0.00%	n/a	n/a
Equity Residential	EQR	0.11%	3.06%	0.00%	5.87%	0.01%
BorgWarner Inc	BWA	0.05%	1.09%	0.00%	5.09%	0.00%
Newfield Exploration Co	NFX	0.03%	n/a	n/a	12.19%	0.00%
Incyte Corp	INCY	0.11%	n/a	n/a	44.05%	0.05%
Simon Property Group Inc	SPG	0.22%	4.47%	0.01%	7.06%	0.02%
Eastman Chemical Co	EMN	0.06%	2.25%	0.00%	7.53%	0.00%
AvalonBay Communities Inc	AVB	0.11%	3.18%	0.00%	6.42%	0.01%
Prudential Financial Inc	PRU	0.20%	2.82%	0.01%	8.00%	0.02%
United Parcel Service Inc	UPS	0.37%	2.76%	0.01%	11.90%	0.04%
Apartment Investment & Management Co	AIV	0.03%	3.28%	0.00%	19.07%	0.01%
Walgreens Boots Alliance Inc	WBA	0.37%	2.07%	0.01%	9.03%	0.03%
McKesson Corp	MCK	0.14%	0.89%	0.00%	5.30%	0.01%
Lockheed Martin Corp	LMT	0.40%	2.58%	0.01%	9.42%	0.04%
AmerisourceBergen Corp	ABC	0.08%	1.76%	0.00%	6.76%	0.01%
Capital One Financial Corp	COF	0.18%	1.89%	0.00%	5.97%	0.01%
Waters Corp	WAT	0.06%	n/a	n/a	8.28%	0.01%
Dollar Tree Inc	DLTR	0.09%	n/a	n/a	12.88%	0.01%
Darden Restaurants Inc	DRI	0.04%	3.20%	0.00%	9.57%	0.00%
NetApp Inc	NTAP	0.05%	1.83%	0.00%	9.90%	0.01%
Citrix Systems Inc	CTXS	0.05%	n/a	n/a	13.10%	0.01%
Goodyear Tire & Rubber Co/The	GT	0.04%	1.20%	0.00%	n/a	n/a
DXC Technology Co	DXC	0.11%	0.84%	0.00%	15.25%	0.02%
DaVita Inc	DVA	0.05%	n/a	n/a	3.75%	0.00%
Hartford Financial Services Group Inc/The	HIG	0.09%	1.66%	0.00%	9.50%	0.01%
Iron Mountain Inc	IRM	0.05%	5.66%	0.00%	14.60%	0.01%
Estee Lauder Cos Inc/The	EL	0.11%	1.26%	0.00%	11.49%	0.01%
Cadence Design Systems Inc	CDNS	0.05%	n/a	n/a	11.45%	0.01%
Principal Financial Group Inc	PFG	0.08%	2.92%	0.00%	10.40%	0.01%
Stericycle Inc	SRCL	0.03%	n/a	n/a	7.68%	0.00%
Universal Health Services Inc	UHS	0.04%	0.36%	0.00%	8.69%	0.00%
E*TRADE Financial Corp	ETFC	0.05%	n/a	n/a	15.37%	0.01%
Skyworks Solutions Inc	SWKS	0.08%	1.26%	0.00%	13.59%	0.01%
National Oilwell Varco Inc	NOV	0.06%	0.56%	0.00%	n/a	n/a
Quest Diagnostics Inc	DGX	0.06%	1.92%	0.00%	6.95%	0.00%
Activision Blizzard Inc	ATVI	0.22%	0.47%	0.00%	13.63%	0.03%
Rockwell Automation Inc	ROK	0.10%	1.71%	0.00%	11.84%	0.01%
Kraft Heinz Co/The	KHC	0.42%	3.22%	0.01%	8.39%	0.04%
American Tower Corp	AMT	0.26%	1.93%	0.01%	20.68%	0.05%
Regeneron Pharmaceuticals Inc	REGN	0.21%	n/a	n/a	18.00%	0.04%
Amazon.com Inc	AMZN	2.06%	n/a	n/a	27.82%	0.57%
Ralph Lauren Corp	RL	0.02%	2.27%	0.00%	0.29%	0.00%
Boston Properties Inc	BXP	0.08%	2.44%	0.00%	4.46%	0.00%
Amphenol Corp	APH	0.12%	0.90%	0.00%	11.23%	0.01%
Arconic Inc	ARNC	0.05%	0.96%	0.00%	16.90%	0.01%
Pioneer Natural Resources Co	PXD	0.11%	0.05%	0.00%	20.00%	0.02%
Valero Energy Corp	VLO	0.15%	3.64%	0.01%	10.45%	0.02%
Synopsys Inc	SNPS	0.05%	n/a	n/a	9.12%	0.00%
L3 Technologies Inc	LLL	0.07%	1.59%	0.00%	6.90%	0.00%
Western Union Co/The	WU	0.04%	3.65%	0.00%	8.00%	0.00%
CH Robinson Worldwide Inc	CHRW	0.05%	2.37%	0.00%	9.20%	0.00%
Accenture PLC	ACN	0.37%	1.97%	0.01%	10.63%	0.04%
TransDigm Group Inc	TDG	0.06%	n/a	n/a	10.21%	0.01%
Yum! Brands Inc	YUM	0.11%	1.63%	0.00%	12.74%	0.01%
Prologis Inc	PLD	0.15%	2.77%	0.00%	6.21%	0.01%
FirstEnergy Corp	FE	0.06%	4.67%	0.00%	n/a	n/a
VeriSign Inc	VRSN	0.05%	n/a	n/a	10.20%	0.00%
Quanta Services Inc	PWR	0.03%	n/a	n/a	8.00%	0.00%
Henry Schein Inc	HSIC	0.06%	n/a	n/a	10.25%	0.01%
Ameren Corp	AEE	0.06%	3.04%	0.00%	n/a	n/a
ANSYS Inc	ANSS	0.05%	n/a	n/a	12.40%	0.01%
NVIDIA Corp	NVDA	0.48%	0.31%	0.00%	12.52%	0.06%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield		1.98%	
[2] Estimated Weighted Average Long-Term Growth Rate		11.46%	
[3] S&P 500 Estimated Required Market Return		13.55%	
[4] Risk-Free Rate	2.77%	3.30%	4.30%
[5] Implied Market Risk Premium	10.78%	10.25%	9.25%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[6] Weight In Index	[7] Estimated Dividend Yield	[8] Cap-Weighted Dividend Yield	[9] Long-Term Growth Estimate	[10] Cap. Weighted Long-Term Growth
Scripps Networks Interactive Inc	SNI	0.04%	1.40%	0.00%	8.53%	0.00%
Sealed Air Corp	SEE	0.04%	1.50%	0.00%	8.12%	0.00%
Cognizant Technology Solutions Corp	CTSH	0.19%	0.83%	0.00%	14.35%	0.03%
Intuitive Surgical Inc	ISRG	0.17%	n/a	n/a	10.05%	0.02%
Aetna Inc	AET	0.24%	1.26%	0.00%	11.46%	0.03%
Affiliated Managers Group Inc	AMG	0.05%	0.42%	0.00%	15.79%	0.01%
Republic Services Inc	RSG	0.10%	2.09%	0.00%	11.46%	0.01%
eBay Inc	EBAY	0.18%	n/a	n/a	8.54%	0.02%
Goldman Sachs Group Inc/The	GS	0.41%	1.26%	0.01%	11.19%	0.05%
Sempra Energy	SRE	0.13%	2.88%	0.00%	14.25%	0.02%
SBA Communications Corp	SBAC	0.08%	n/a	n/a	23.05%	0.02%
Moody's Corp	MCO	0.12%	1.09%	0.00%	8.00%	0.01%
Priceline Group Inc/The	PCLN	0.40%	n/a	n/a	17.26%	0.07%
F5 Networks Inc	FFIV	0.03%	n/a	n/a	11.85%	0.00%
Akamai Technologies Inc	AKAM	0.04%	n/a	n/a	13.40%	0.00%
Devon Energy Corp	DVN	0.09%	0.65%	0.00%	18.42%	0.02%
Alphabet Inc	GOOGL	1.30%	n/a	n/a	16.64%	0.22%
Red Hat Inc	RHT	0.09%	n/a	n/a	17.00%	0.01%
Allegion PLC	ALLE	0.04%	0.74%	0.00%	13.09%	0.00%
Netflix Inc	NFLX	0.35%	n/a	n/a	40.60%	0.14%
Agilent Technologies Inc	A	0.09%	0.82%	0.00%	9.53%	0.01%
Anthem Inc	ANTM	0.22%	1.47%	0.00%	9.78%	0.02%
CME Group Inc	CME	0.21%	1.95%	0.00%	10.47%	0.02%
Juniper Networks Inc	JNPR	0.05%	1.44%	0.00%	8.62%	0.00%
BlackRock Inc	BLK	0.32%	2.24%	0.01%	13.60%	0.04%
DTE Energy Co	DTE	0.09%	3.07%	0.00%	5.35%	0.00%
Nasdaq Inc	NDAQ	0.06%	1.96%	0.00%	9.08%	0.01%
Philip Morris International Inc	PM	0.77%	3.86%	0.03%	9.61%	0.07%
salesforce.com Inc	CRM	0.30%	n/a	n/a	28.05%	0.08%
MetLife Inc	MET	0.25%	3.08%	0.01%	35.90%	0.09%
Under Armour Inc	UA	0.01%	n/a	n/a	9.68%	0.00%
Monsanto Co	MON	0.24%	1.80%	0.00%	7.47%	0.02%
Coach Inc	COH	0.05%	3.35%	0.00%	11.57%	0.01%
Fluor Corp	FLR	0.03%	2.00%	0.00%	11.89%	0.00%
CSX Corp	CSX	0.22%	1.47%	0.00%	11.33%	0.03%
Edwards Lifesciences Corp	EW	0.10%	n/a	n/a	16.60%	0.02%
Ameriprise Financial Inc	AMP	0.10%	2.24%	0.00%	10.40%	0.01%
Xcel Energy Inc	XEL	0.11%	3.04%	0.00%	6.05%	0.01%
Rockwell Collins Inc	COL	0.09%	1.01%	0.00%	10.73%	0.01%
TechnipFMC PLC	FTI	0.06%	n/a	n/a	8.59%	0.01%
Zimmer Biomet Holdings Inc	ZBH	0.11%	0.82%	0.00%	8.38%	0.01%
CBRE Group Inc	CBG	0.06%	n/a	n/a	9.35%	0.01%
Mastercard Inc	MA	0.66%	0.62%	0.00%	16.63%	0.11%
Signet Jewelers Ltd	SIG	0.02%	1.86%	0.00%	3.40%	0.00%
CarMax Inc	KMX	0.06%	n/a	n/a	13.79%	0.01%
Intercontinental Exchange Inc	ICE	0.18%	1.16%	0.00%	10.98%	0.02%
Fidelity National Information Services Inc	FIS	0.14%	1.24%	0.00%	8.23%	0.01%
Chipotle Mexican Grill Inc	CMG	0.04%	n/a	n/a	50.05%	0.02%
Wynn Resorts Ltd	WYNN	0.07%	1.34%	0.00%	31.90%	0.02%
Assurant Inc	AIZ	0.02%	2.22%	0.00%	19.35%	0.00%
NRG Energy Inc	NRG	0.04%	0.47%	0.00%	n/a	n/a
Monster Beverage Corp	MNST	0.14%	n/a	n/a	20.30%	0.03%
Regions Financial Corp	RF	0.08%	2.36%	0.00%	13.86%	0.01%
Mosaic Co/The	MOS	0.03%	2.78%	0.00%	11.70%	0.00%
Expedia Inc	EXPE	0.09%	0.83%	0.00%	17.98%	0.02%
Discovery Communications Inc	DISCA	0.01%	n/a	n/a	9.70%	0.00%
CF Industries Holdings Inc	CF	0.04%	3.41%	0.00%	6.00%	0.00%
Viacom Inc	VIAB	0.04%	2.87%	0.00%	2.96%	0.00%
Wyndham Worldwide Corp	WYN	0.05%	2.20%	0.00%	14.25%	0.01%
Alphabet Inc	GOOG	1.49%	n/a	n/a	16.64%	0.25%
TE Connectivity Ltd	TEL	0.13%	1.93%	0.00%	6.87%	0.01%
Cooper Cos Inc/The	COO	0.05%	0.03%	0.00%	9.75%	0.01%
Discover Financial Services	DFS	0.11%	2.17%	0.00%	3.98%	0.00%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

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STANDARD AND POOR'S 500 INDEX

Name	Ticker	[6] Weight In Index	[7] Estimated Dividend Yield	[8] Cap-Weighted Dividend Yield	[9] Long-Term Growth Estimate	[10] Cap. Weighted Long-Term Growth
TripAdvisor Inc	TRIP	0.02%	n/a	n/a	14.50%	0.00%
Dr Pepper Snapple Group Inc	DPS	0.07%	2.62%	0.00%	8.58%	0.01%
Visa Inc	V	0.86%	0.63%	0.01%	16.76%	0.14%
Mid-America Apartment Communities Inc	MAA	0.05%	3.26%	0.00%	n/a	n/a
Xylem Inc/NY	XYL	0.05%	1.15%	0.00%	15.00%	0.01%
Marathon Petroleum Corp	MPC	0.13%	2.85%	0.00%	12.68%	0.02%
Level 3 Communications Inc	LVLT	0.09%	n/a	n/a	5.00%	0.00%
Tractor Supply Co	TSCO	0.04%	1.71%	0.00%	13.65%	0.00%
ResMed Inc	RMD	0.05%	1.82%	0.00%	11.56%	0.01%
Mettler-Toledo International Inc	MTD	0.07%	n/a	n/a	12.08%	0.01%
Albemarle Corp	ALB	0.07%	0.94%	0.00%	12.17%	0.01%
Essex Property Trust Inc	ESS	0.07%	2.76%	0.00%	5.99%	0.00%
GGP Inc	GGP	0.08%	4.24%	0.00%	4.65%	0.00%
Realty Income Corp	O	0.07%	4.45%	0.00%	4.42%	0.00%
Seagate Technology PLC	STX	0.04%	7.60%	0.00%	8.73%	0.00%
WestRock Co	WRK	0.06%	2.82%	0.00%	9.67%	0.01%
IHS Markit Ltd	INFO	0.08%	n/a	n/a	13.51%	0.01%
Western Digital Corp	WDC	0.11%	2.31%	0.00%	11.74%	0.01%
Church & Dwight Co Inc	CHD	0.05%	1.57%	0.00%	9.14%	0.00%
Duke Realty Corp	DRE	0.05%	2.64%	0.00%	4.52%	0.00%
Federal Realty Investment Trust	FRT	0.04%	3.22%	0.00%	4.67%	0.00%
MGM Resorts International	MGM	0.08%	1.35%	0.00%	17.46%	0.01%
Twenty-First Century Fox Inc	FOX	0.09%	1.40%	0.00%	9.23%	0.01%
Alliant Energy Corp	LNT	0.04%	3.03%	0.00%	5.50%	0.00%
JB Hunt Transport Services Inc	JBHT	0.05%	0.83%	0.00%	13.35%	0.01%
Lam Research Corp	LRCX	0.13%	0.97%	0.00%	7.70%	0.01%
Mohawk Industries Inc	MHK	0.08%	n/a	n/a	8.48%	0.01%
Pentair PLC	PNR	0.06%	2.03%	0.00%	8.04%	0.00%
Vertex Pharmaceuticals Inc	VRTX	0.17%	n/a	n/a	72.50%	0.12%
Facebook Inc	FB	1.81%	n/a	n/a	26.79%	0.48%
United Rentals Inc	URI	0.05%	n/a	n/a	14.17%	0.01%
Alexandria Real Estate Equities Inc	ARE	0.05%	2.89%	0.00%	6.80%	0.00%
United Continental Holdings Inc	UAL	0.08%	n/a	n/a	-0.23%	0.00%
Navient Corp	NAVI	0.02%	4.26%	0.00%	8.00%	0.00%
Delta Air Lines Inc	DAL	0.16%	2.53%	0.00%	5.57%	0.01%
News Corp	NWS	0.01%	1.47%	0.00%	12.59%	0.00%
Centene Corp	CNC	0.07%	n/a	n/a	12.48%	0.01%
Regency Centers Corp	REG	0.05%	3.42%	0.00%	9.26%	0.00%
Macerich Co/The	MAC	0.03%	5.17%	0.00%	7.66%	0.00%
Martin Marietta Materials Inc	MLM	0.06%	0.85%	0.00%	21.24%	0.01%
Envision Healthcare Corp	EVHC	0.02%	n/a	n/a	8.03%	0.00%
PayPal Holdings Inc	PYPL	0.34%	n/a	n/a	19.83%	0.07%
Coty Inc	COTY	0.06%	3.02%	0.00%	17.00%	0.01%
DISH Network Corp	DISH	0.06%	n/a	n/a	-7.33%	0.00%
Alexion Pharmaceuticals Inc	ALXN	0.14%	n/a	n/a	20.50%	0.03%
Everest Re Group Ltd	RE	0.04%	2.19%	0.00%	10.00%	0.00%
News Corp	NWSA	0.02%	1.51%	0.00%	12.59%	0.00%
Global Payments Inc	GPN	0.06%	0.04%	0.00%	14.50%	0.01%
Crown Castle International Corp	CCI	0.18%	3.80%	0.01%	21.60%	0.04%
Delphi Automotive PLC	DLPH	0.12%	1.18%	0.00%	12.18%	0.01%
Advance Auto Parts Inc	AAP	0.03%	0.24%	0.00%	8.96%	0.00%
Michael Kors Holdings Ltd	KORS	0.03%	n/a	n/a	7.00%	0.00%
Align Technology Inc	ALGN	0.07%	n/a	n/a	30.00%	0.02%
Illumina Inc	ILMN	0.13%	n/a	n/a	15.48%	0.02%
Acuity Brands Inc	AYI	0.03%	0.30%	0.00%	17.67%	0.01%
Alliance Data Systems Corp	ADS	0.05%	0.94%	0.00%	14.00%	0.01%
LKQ Corp	LKQ	0.05%	n/a	n/a	12.50%	0.01%
Nielsen Holdings PLC	NLSN	0.07%	3.28%	0.00%	10.00%	0.01%
Garmin Ltd	GRMN	0.05%	3.78%	0.00%	5.68%	0.00%
Cimarex Energy Co	XEC	0.05%	0.28%	0.00%	63.66%	0.03%
Zoetis Inc	ZTS	0.14%	0.66%	0.00%	14.75%	0.02%
Digital Realty Trust Inc	DLR	0.11%	3.14%	0.00%	5.58%	0.01%
Equinix Inc	EQIX	0.16%	1.79%	0.00%	29.25%	0.05%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

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[5] Implied Market Risk Premium	10.78%	10.25%	9.25%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[6] Weight In Index	[7] Estimated Dividend Yield	[8] Cap-Weighted Dividend Yield	[9] Long-Term Growth Estimate	[10] Cap. Weighted Long-Term Growth
Discovery Communications Inc	DISCK	0.02%	n/a	n/a	9.70%	0.00%

Notes:
[1] Equals sum of col. [8]
[2] Equals sum of col. [10]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Source: Bloomberg Professional and Blue Chip Financial Forecasts
[5] Equals [3] - [4]
[6] Equals weight in S&P 500 based on market capitalization
[7] Source: Bloomberg Professional
[8] Equals [6] x [7]
[9] Source: Bloomberg Professional
[10] Equals [6] x [9]

CAPITAL ASSET PRICING MODEL

$$K = Rf + \beta\ (Rm - Rf)$$

	[4]	[5]	[6]	[7]	[8]
	Risk-Free Rate *(Rf)*	Beta *(β)*	Market Return *(Rm)*	Market Risk Premium *(Rm − Rf)*	ROE *(K)*
Proxy Group Average Bloomberg Beta					
Current 30-day average of 30-year U.S. Treasury bond yield [1]	2.77%	0.565	13.55%	10.78%	8.86%
Near-term projected 30-year U.S. Treasury bond yield (Q4 2017 - Q1 2019) [2]	3.30%	0.565	13.55%	10.25%	9.09%
Projected 30-year U.S. Treasury bond yield (2019 - 2023) [3]	4.30%	0.565	13.55%	9.25%	9.52%
				Average:	**9.16%**
				Median:	**9.09%**
Proxy Group Average Value Line Beta					
Current 30-day average of 30-year U.S. Treasury bond yield [1]	2.77%	0.700	13.55%	10.78%	10.32%
Near-term projected 30-year U.S. Treasury bond yield (Q4 2017 - Q1 2019) [2]	3.30%	0.700	13.55%	10.25%	10.48%
Projected 30-year U.S. Treasury bond yield (2019 - 2023) [3]	4.30%	0.700	13.55%	9.25%	10.78%
				Average:	**10.52%**
				Median:	**10.48%**

Notes:

[1] Source: Bloomberg Professional, 30-day average as of September 29, 2017
[2] Source: Blue Chip Financial Forecasts, Vol. 36, No. 10, October 1, 2017, at 2
[3] Source: Blue Chip Financial Forecasts, Vol. 36, No. 6, June 1, 2017, at 14
[4] See Notes [1], [2], and [3]
[5] Source: Bloomberg Professional and Value Line
[6] Source: Bloomberg Professional
[7] Equals [6] − [4]
[8] Equals [4] + [5] x [7]

FLOTATION COST ADJUSTMENT

Flotation Costs from Inception to Date

Date	Shares Issued	Market Price	Offering Price	Underwriting Discount	Offering Expense	Net Proceeds	Total Flotation Costs	Gross Equity Issue before Costs	Net Proceeds	Flotation Cost Percentage
11/16/1949	1,584,238	$10.750	$10.250	$0.124	$0.137	$9.989	$1,205,605	$17,030,559	$15,824,953	7.079%
6/4/1952	1,108,966	$10.500	$10.500	$0.098	$0.162	$10.240	$288,331	$11,644,143	$11,355,812	2.476%
4/14/1954	1,219,856	$15.250	$14.000	$0.060	$0.124	$13.816	$1,749,274	$18,602,804	$16,853,530	9.403%
2/29/1956	670,920	$17.825	$16.750	$0.050	$0.221	$16.479	$903,058	$11,959,149	$11,056,091	7.551%
7/22/1959	952,033	$23.375	$22.000	$0.069	$0.191	$21.740	$1,556,574	$22,253,771	$20,697,197	6.995%
7/28/1965	772,008	$35.250	$33.000	$0.092	$0.225	$32.683	$1,981,745	$27,213,282	$25,231,537	7.282%
1/22/1969	1,080,811	$29.000	$27.000	$0.119	$0.187	$26.694	$2,492,350	$31,343,519	$28,851,169	7.952%
10/21/1970	1,729,298	$23.125	$21.500	$0.175	$0.149	$21.176	$3,370,402	$39,990,016	$36,619,614	8.428%
7/26/1972	1,902,228	$25.000	$23.500	$0.129	$0.166	$23.205	$3,414,499	$47,555,700	$44,141,201	7.180%
10/10/1973	2,092,451	$25.825	$24.500	$0.128	$0.153	$24.219	$3,360,476	$54,037,547	$50,677,071	6.219%
11/20/1974	2,300,000	$17.625	$17.500	$0.910	$0.069	$16.521	$2,539,200	$40,537,500	$37,998,300	6.264%
8/14/1975	1,750,000	$23.000	$23.000	$0.740	$0.077	$22.183	$1,429,750	$40,250,000	$38,820,250	3.552%
6/3/1976	2,000,000	$24.000	$24.000	$0.720	$0.064	$23.216	$1,568,000	$48,000,000	$46,432,000	3.267%
5/31/1993	3,041,955	$44.125	$43.625	$1.200	$0.048	$42.377	$5,317,337	$134,226,264	$128,908,927	3.961%
9/23/1997	4,500,000	$49.938	$49.563	$1.230	$0.133	$48.200	$7,821,000	$224,721,000	$216,900,000	3.480%
9/29/1997	400,000	$50.500	$49.563	$1.230	$0.133	$48.200	$920,000	$20,200,000	$19,280,000	4.554%
2/25/2002	20,000,000	$22.950	$22.500	$0.730	$0.015	$21.755	$23,900,000	$459,000,000	$435,100,000	5.207%
9/9/2008	17,250,000	$20.860	$20.200	$0.100	$0.006	$20.094	$13,218,352	$359,835,000	$346,616,648	3.673%
8/3/2010	21,850,000	$22.100	$21.500	$0.645	$0.013	$20.571	$33,407,927	$482,885,000	$449,477,073	6.918% [1]
March 2013	7,757,449	$29.057	$29.057	$0.291	$0.052	$28.714	$2,657,558	$225,407,642	$222,750,085	1.179%
June 2014	5,693,946	$30.663	$30.663	$0.307	$0.030	$30.326	$1,915,210	$174,592,340	$172,677,130	1.097%
Total Public Issuances							$115,016,648	$2,491,285,237	$2,376,268,590	4.617%
Total Non-Public Issuances							$0	$1,548,782,000	$1,548,782,000	0.000%
Total Weighted Flotation Costs							$115,016,648	$4,040,067,237	$3,925,050,590	2.847%

The flotation adjustment is derived by dividing the dividend yield by 1-F (where F = flotation costs expressed in percentage terms), or by 0.9715, and adding that result to the constant growth rate to determine the cost of equity. Using the formulas shown previously in my testimony, the Constant Growth DCF calculation is modified as follows to accommodate an adjustment for flotation costs:

$$k = \frac{D \times (1 + .5g)}{P \times (1 - F)} + g$$

Source: Company data.

[1] This issuance was structured as a forward equity sale. The spread between the initial forward sale price (*i.e.* , $20.855) and the actual forward settle price (*i.e.* , $20.584) is reflected in the net proceeds.

FLOTATION COST ADJUSTMENT

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
		Stock Price	Annualized Dividend	Dividend Yield	Expected Dividend Yield	Expected Dividend Yield Adjusted for Flotation Costs	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Estimate	DCF k(e)	Flotation Adjusted DCF k(e)
ALLETE, Inc.	ALE	$77.39	$2.14	2.77%	2.84%	2.93%	6.00%	5.00%	6.10%	5.70%	8.54%	8.63%
Alliant Energy Corporation	LNT	$42.56	$1.26	2.96%	3.05%	3.14%	6.00%	6.90%	5.50%	6.13%	9.18%	9.27%
Ameren Corporation	AEE	$59.52	$1.76	2.96%	3.05%	3.14%	6.00%	6.10%	6.50%	6.20%	9.25%	9.34%
American Electric Power Company, Inc.	AEP	$72.66	$2.36	3.25%	3.31%	3.41%	4.00%	2.87%	5.40%	4.09%	7.40%	7.50%
Duke Energy Corporation	DUK	$86.41	$3.56	4.12%	4.20%	4.32%	4.50%	2.65%	4.00%	3.72%	7.91%	8.04%
El Paso Electric Company	EE	$55.14	$1.34	2.43%	2.51%	2.58%	5.00%	6.50%	7.20%	6.23%	8.74%	8.81%
Hawaiian Electric Industries, Inc.	HE	$33.54	$1.24	3.70%	3.74%	3.85%	1.50%	1.40%	4.00%	2.30%	6.04%	6.15%
IDACORP, Inc.	IDA	$89.09	$2.20	2.47%	2.52%	2.59%	3.50%	4.00%	4.50%	4.00%	6.52%	6.59%
OGE Energy Corporation	OGE	$36.07	$1.21	3.35%	3.45%	3.55%	6.00%	6.30%	5.30%	5.87%	9.32%	9.42%
Pinnacle West Capital Corporation	PNW	$88.58	$2.62	2.96%	3.04%	3.13%	5.50%	6.04%	5.20%	5.58%	8.62%	8.71%
PNM Resources, Inc.	PNM	$42.01	$0.97	2.31%	2.39%	2.46%	9.00%	7.35%	4.70%	7.02%	9.41%	9.48%
Portland General Electric Company	POR	$46.85	$1.36	2.90%	2.97%	3.06%	6.00%	4.90%	3.50%	4.80%	7.77%	7.86%
PPL Corporation	PPL	$39.04	$1.58	4.05%	4.10%	4.22%	NMF	0.04%	5.00%	2.52%	6.62%	6.74%
Southern Company	SO	$49.04	$2.32	4.73%	4.82%	4.96%	3.50%	3.22%	4.30%	3.67%	8.49%	8.63%
		PROXY GROUP MEAN		3.21%	3.29%	3.38%	5.12%	4.52%	5.09%	4.85%	8.13%	8.23%

MEAN		8.23%
UNADJUSTED CONSTANT GROWTH DCF MEAN		8.13%
DIFFERENCE (FLOTATION COST ADJUSTMENT)	[12]	0.10%

[1] Source: Bloomberg Professional, equals 30-day average as of September 29, 2017
[2] Source: Bloomberg Professional
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [9])
[5] Equals [4] /(1- [Flotation Cost Percentage])
[6] Source: Value Line
[7] Source: Yahoo! Finance
[8] Source: Zacks
[9] Equals average ([6], [7], [8])
[10] Equals [4] + [9]
[11] Equals [5] + [9]
[12] Equals [11] - [10]

Redline

APPLICATION

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

RIDER

There shall be included on each customer's monthly bill a Transmission Cost Recovery (TCR) adjustment, which shall be the TCR Adjustment Factor multiplied by the customer's monthly billing energy or demand for electric service as described below. This TCR Adjustment shall be calculated before city surcharge and sales tax.

DETERMINATION OF TCR ADJUSTMENT FACTORS

A separate TCR Adjustment Factor shall be calculated for the following ~~four~~three customer groups: (1) Residential, (2) Commercial Non-Demand, and (3) Demand Billed~~, and (4) Street Lighting~~. The TCR Adjustment Factor for each group shall be the value obtained by multiplying each group's weighting factor by the average retail cost per kWh. The average retail cost per kWh shall be determined by the forecasted balance of the TCR Tracker Account, divided by the forecasted retail sales for the calendar year. The Demand Billed customers' TCR Adjustment Factor is calculated similarly, but the resulting per kWh charge is converted to a per kW charge for application to billed kW rather than billed kWh. TCR Adjustment Factors shall be rounded to the nearest $0.000001 per kWh or $0.001 per kW. C C

The TCR Adjustment Factor for each customer group may be adjusted annually with approval of the Minnesota Public Utilities Commission (Commission). Each TCR Adjustment Factor shall apply to bills rendered subsequent to approval by the ~~Minnesota Public Utilities~~ Commission. The TCR factor for each rate schedule is: T

Residential	~~$0.003503~~$0.004645 per kWh	R
Commercial (Non-Demand)	~~$0.003384~~$0.004102 per kWh	R
Demand Billed	~~$1.017~~$1.274 per kW	R

Recoverable Transmission and Distribution Costs shall be the annual revenue requirements for transmission and distribution costs associated with transmission projects and distribution planning and facilities eligible for recovery under Minnesota Statute Sections 216B.1645 or 216B.16, subd. 7b that are determined by the Commission to be eligible for recovery under this Transmission Cost Recovery Rider. A standard model will be used to calculate the total forecasted revenue requirements for eligible projects for the designated period. All costs appropriately charged to the Transmission Tracker Account shall be eligible for recovery through this Rider, and all revenues recovered from the TCR Adjustment shall be credited to the Transmission Tracker Account. C C

Forecasted retail kWh sales and kW demands shall be those for the designated recovery period.

(Continued on Sheet No. 5-145)

Clean

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

RIDER
There shall be included on each customer's monthly bill a Transmission Cost Recovery (TCR) adjustment, which shall be the TCR Adjustment Factor multiplied by the customer's monthly billing energy or demand for electric service as described below. This TCR Adjustment shall be calculated before city surcharge and sales tax.

DETERMINATION OF TCR ADJUSTMENT FACTORS
A separate TCR Adjustment Factor shall be calculated for the following three customer groups: (1) Residential, C
(2) Commercial Non-Demand, and (3) Demand Billed. The TCR Adjustment Factor for each group shall be the C
value obtained by multiplying each group's weighting factor by the average retail cost per kWh. The average retail cost per kWh shall be determined by the forecasted balance of the TCR Tracker Account, divided by the forecasted retail sales for the calendar year. The Demand Billed customers' TCR Adjustment Factor is calculated similarly, but the resulting per kWh charge is converted to a per kW charge for application to billed kW rather than billed kWh. TCR Adjustment Factors shall be rounded to the nearest $0.000001 per kWh or $0.001 per kW.

The TCR Adjustment Factor for each customer group may be adjusted annually with approval of the Minnesota Public Utilities Commission (Commission). Each TCR Adjustment Factor shall apply to bills rendered subsequent to approval by the Commission. The TCR factor for each rate schedule is: T

Residential	$0.004645 per kWh	R
Commercial (Non-Demand)	$0.004102 per kWh	R
Demand Billed	$1.274 per kW	R

Recoverable Transmission and Distribution Costs shall be the annual revenue requirements for transmission C
and distribution costs associated with transmission projects and distribution planning and facilities eligible for C
recovery under Minnesota Statute Sections 216B.1645 or 216B.16, subd. 7b that are determined by the Commission to be eligible for recovery under this Transmission Cost Recovery Rider. A standard model will be used to calculate the total forecasted revenue requirements for eligible projects for the designated period. All costs appropriately charged to the Transmission Tracker Account shall be eligible for recovery through this Rider, and all revenues recovered from the TCR Adjustment shall be credited to the Transmission Tracker Account.

Forecasted retail kWh sales and kW demands shall be those for the designated recovery period.

(Continued on Sheet No. 5-145)

CERTIFICATE OF SERVICE

I, Lynnette Sweet, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

XCEL ENERGY MISCELLANEOUS ELECTRIC SERVICE LIST

Dated this 8th day of November 2017

/s/

____

Lynnette Sweet

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