414 Nicollet Mall
Minneapolis, Minnesota 55401

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November 17, 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
RENEWABLE ENERGY STANDARD 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 our 2017 and 2018 Renewable Energy Standard Rider revenue requirements.

Please note that portions of our Petition and Attachment I are marked as "Not Public." Certain data is considered to be "not public data" pursuant to Minn. Stat. §13.02, Subd.9, and is "Trade Secret" information pursuant to Minn. Stat. §13.37, subd. 1(b) as this data derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.

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 lists.

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

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STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE RENEWABLE ENERGY STANDARD RIDER REVENUE REQUIREMENTS FOR 2017 AND 2018 AND REVISED ADJUSTMENT FACTORS

DOCKET NO. E002/M-17-____

PETITION

OVERVIEW

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Petition requesting approval of our Renewable Energy Standard (RES) Rider revenue requirements for 2017 and 2018 and our proposed RES Adjustment Factors.

We have taken several proactive measures to keep bills low for our customers in ways that directly impact the RES Rider. First, we continue to make investments in renewable wind resources that bring clean energy to our customers while reducing fuel costs. We have timed construction and in-servicing of these projects to take advantage of federal production tax credits (PTCs). We plan to recover the costs of building these new wind resources through the RES Rider, but customers will also receive the benefit of PTCs that are trued up through the rider, as well as reduced fuel costs in the Fuel Cost Adjustment (FCA). Second, there continues to be a market for renewable energy credits (RECs). We have been pursuing opportunities to sell RECs, and the proceeds from these sales are credited back to customers through the RES Rider.

The 2017 and 2018 RES Rider revenue requirements have been calculated to include costs and expenses associated with the Courtenay Wind farm and the recently-approved Wind Portfolio projects totaling 1,550 MW of new nameplate capacity. The revenue requirements are off-set by a true-up of actual production tax credits (PTCs) through September 2017, a PTC forecast for the remainder of 2017 and 2018, and the proceeds from REC sales. Due to the significant amount of REC sales that have occurred since our last RES Rider Petition was filed in 2015, and because wind production has been greater than forecasted, the 2017 revenue requirements are negative $10.3 million for 2017. The 2018 revenue requirements are $10.5 million as the new wind projects enter the construction phase.

We propose to set a one-month refund rate of -6.384% in February 2018 to refund the 2017 over-collection to customers. We would then implement a new rate of 0.497% in March 2018 to collect the 2018 revenue requirements over the remaining months of the year.[1] This proposal will allow a more timely refund to the customers who were charged the RES Rider rate in 2017, and it also serves as a rate smoothing mechanism since the RES Rider revenue requirements are expected to increase over the next several years.

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

In support of our request, our Petition provides:

- details about the self-build and build-own-transfer Wind Portfolio projects in support of RES Rider recovery;
- an update on the now in-service Courtenay Wind project which has previously been approved for RES Rider recovery;
- a schedule detailing the REC sales that have occurred since our last RES Rider Petition;
- schedules detailing the PTC actual and forecasted amounts for 2017 and 2018, as well as tax documentation for 2015 and 2016;
- a proposed ROE for use in calculating the RES Rider 2017 and 2018 revenue requirements along with supporting analysis; and
- a proposed plan to smooth the RES Rider rates over the next several years through a one-time refund for 2017 and a new Adjustment Factor for 2018.

I. SUMMARY OF FILING

Pursuant to Minn. R. 7829.1300, subp. 1, a one-paragraph summary of the filing accompanies this petition.

[1] In compliance with past orders, the percentage factors are based on the quotient of the RES Rider cost over the base revenues without fuel, riders, and taxes, corresponding to the period of recovery. The percentages are then applied to actual base revenues.

II. SERVICE ON OTHER PARTIES

Pursuant to Minn. R. 7829.1300, subp. 2, we will serve a copy of the Petition Summary on all parties on Xcel Energy's miscellaneous electric service list.

III. GENERAL FILING INFORMATION

Pursuant to Minn. R. 7829.1300, subp. 3, Xcel Energy 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 17, 2017. The Company proposes the updated RES Rider rate 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. We propose to refund the RES Rider over-collection for 2017 through a one-month Adjustment Factor to be effective February 1, 2018 and a new Adjustment Factor to collect the 2018 revenue requirements to be effective March 1, 2018. Should the Commission approve this Petition after February 1, 2018, 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.1645, Subd. 2a states that a utility may petition the Commission to approve a rate schedule that provides for the automatic adjustment of charges to recover prudently incurred investments, expenses, or costs associated with facilities constructed, owned, or operated by a utility to satisfy the requirements of section 216B.1691, provided those facilities were previously approved by the Commission. We are filing this Petition in accordance with Minn. Stat. § 216B.16, Subd. 1, which prescribes general timelines for rate and tariff changes, including, but not limited to, a requirement of a 60 day notice prior to any rate or tariff change.

Commission Rules define this filing as a "miscellaneous rate change" under Minn. R. 7829.0100, subp. 11. The accounting process that we will use to track revenues, costs and record the differences in the RES Rider Tracker account will comply with Accounting Standards prescribed under Minn. Stat. § 216B.10.

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

Pursuant to Minn. R. 7829.0700, Xcel Energy requests that the following persons be placed on the Commission's official service list for this matter:

Amanda Rome	Carl Cronin
Lead Assistant General Counsel	Regulatory Administrator
Xcel Energy	Xcel Energy
414 Nicollet Mall, 401-8th Floor	414 Nicollet Mall, 401-7th Floor
Minneapolis, MN 55401	Minneapolis, MN 55401
amanda.rome@xcelenergy.com	regulatory.records@xcelenergy.com

Any information requests in this proceeding should be submitted to Mr. Cronin at the Regulatory Records email address above.

V. DESCRIPTION AND PURPOSE OF FILING

A. Background

The RES Rider is designed to allow for the automatic adjustment of charges to recover prudently-incurred investments, expenses, or costs associated with facilities constructed, owned, or operated by a utility to satisfy the RES Statute,[2] provided those facilities were previously approved by the Commission.[3] Through subsequent Commission Orders in dockets discussed further below, the RES Rider tracker also incorporates proceeds from the sales of renewable energy credits and a true-up to actuals of production tax credits associated with Company-owned wind farms.

Our last RES Rider Petition was filed on September 1, 2015 and requested approval of forecasted 2016 revenue requirements. The Commission's Order in that proceeding was issued on April 11, 2017 and authorized a RES Rider Adjustment Factor based on updating the tracker with 2016 actual capital expenditures, PTCs, and revenues. The current adjustment factor of 0.497 percent is based on 2016 actual revenues and expenses and was implemented on May 1, 2017.

In this filing, we request approval to recover through the RES Rider the costs and expenses related to several new self-build and build-own-transfer wind farms that are part of a larger Wind Portfolio. We have calculated the RES Rider revenue requirements to include costs and expenses associated with the Courtenay Wind farm and the Wind Portfolio projects, in addition to a true-up of actual PTCs through September 2017 and a PTC forecast for the remainder of 2017 and 2018, which is then offset by the proceeds from sales of RECs that have occurred since our last RES Rider Petition was filed.

B. RES Eligibility of Wind Portfolio Projects[4]

The Company's Wind Portfolio includes four new self-build wind farms and two build-own-transfer projects that the Company identified through its September 2016 Request for Proposals (RFP) for additional wind resources. Ordering Point No. 6 of the Commission's September 1, 2017 Order in Docket No. E002/M-16-777 found that the Company's proposal is a reasonable and prudent approach to meeting its obligation under Minnesota's Renewable Energy Standard. We have therefore included the costs and expenses associated with these six wind farms in our calculation of the 2017 and 2018 RES Rider revenue requirements. We acknowledge that Ordering Point No. 1a holds the Company accountable for the prices and terms used to evaluate each of the selected projects for the purpose of cost recovery and that Ordering Point No. 1b requires that ratepayers will not be put at risk for any

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[2] Minn. Stat. § 216B.1691
[3] Minn. Stat § 216B.1645
[4] We note that we have filed for Commission approval of one additional wind project outside of the Wind Portfolio, the Dakota Range project (Docket No. E002/M-17-694). Should the Commission approve the project while the RES Rider proceeding is still in process, we will file a Supplement to this Petition.

costs that are higher than bid. Attachment F shows the current forecast of capital costs for these projects.

Our four self-build projects total 750 MW. We plan to manage these projects as a portfolio, and the Commission approved our proposal to subject cost recovery to an aggregate, symmetrical capital cap (including AFUDC) of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** for the entire self-build Wind Portfolio.[5] In addition, our RES Rider request includes two build-own-transfer projects totaling 400 MW.

These projects were selected after a thorough bid evaluation process that included the review of many aspects of several project sites across our region including location, wind availability, transmission and interconnection considerations, siting issues and more. The following six projects comprise the self-build and build-own-transfer Wind Portfolio and are included in our RES Rider recovery request.

Table 1: Wind Portfolio Projects Included in the RES Rider

Project Name	Size	Type	Location
Blazing Star I	200 MW	Self-Build	Lincoln County, MN
Blazing Star II	200 MW	Self-Build	Lincoln County, MN
Foxtail	150 MW	Self-Build	Dickey County, ND
Freeborn	200 MW	Self-Build	Freeborn County, MN and Worth and Mitchell Counties, IA
Crowned Ridge[6]	300 MW	BOT	Codington County, SD
Lake Benton	100 MW	BOT	Pipestone County, MN

1. *Blazing Star I*

The 200 MW Blazing Star I Wind Project is being developed by Geronimo Energy and is located on approximately 37,200 acres in Hansonville, Hendricks, and Marble Townships, Minnesota. As presented in the Wind RFP docket, total capital costs for the Blazing Star I Wind Project were estimated to be approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**, which includes the estimated transmission upgrades and interconnection costs as well as anticipated siting and permitting costs. We expect our primary construction activities on the Blazing Star I Wind Project will occur in 2019. Under the current projected schedule, we anticipate that commercial operation will be achieved by December 2019.

[5] See Ordering Point No. 5.

[6] We note that this project includes an additional 300 MW of capacity through a Power Purchase Agreement (PPA) with NextEra. Costs associated with the PPA are not included in the costs shown for this project in the RES Rider.

2. Blazing Star II

The 200 MW Blazing Star II Wind Project is also being developed by Geronimo Energy. It extends the Blazing Star I Project footprint east and south – and is located on approximately 30,000 acres of predominantly active crop land. As presented in the Wind RFP docket, total capital costs for the Blazing Star II Project were estimated to be approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**, which includes the estimated transmission upgrades and interconnection costs as well as anticipated siting and permitting costs. We expect our primary construction activities on the Blazing Star II Wind Project will occur in 2019 and early 2020. Under the current projected schedule, we anticipate that commercial operation will be achieved by September 2020.

3. Foxtail

The 150 MW Foxtail Wind Project is being developed by an affiliate of NextEra Energy Inc., and is located on an approximately 20,000 acre site located 20 miles West of Ellendale, North Dakota.

As presented in the Wind RFP docket, total capital costs for the Foxtail Project were estimated to be approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**, which includes estimated transmission upgrades and interconnection costs as well as anticipated siting and permitting costs. We expect our primary construction activities on the Foxtail Project will occur in 2018 and 2019 with engineering and some procurement occurring in 2017. Under the current projected schedule, we anticipate that commercial operation will be achieved by September 2019.

4. Freeborn

The 200 MW Freeborn Wind Project is being developed by an affiliate of Invenergy Wind Development LLC, and is located on an approximately 40,000 acre site near Glenville, Minnesota. Land acquisition was completed during summer 2017. We expect that approximately 56-84 MW of this project—including the collection substation, point of interconnection, and O&M Building—will be located in Minnesota's Freeborn County and that the remaining 116-144 MW will be located in Iowa's Worth County.

As presented in the Wind RFP docket, total capital costs for the Freeborn Project were estimated to be approximately **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS], which includes the estimated transmission upgrades and interconnection costs as well as anticipated siting and permitting costs. We expect our primary construction activities on the Freeborn Project will occur in 2020. Under the current projected schedule, we anticipate that commercial operation will be achieved by early December 2020.

5. Crowned Ridge

The Crowned Ridge Wind Project is included in the Wind Portfolio in two parts: 300 MW of nameplate capacity through a PPA and 300.6 MW of nameplate capacity through a build-own-transfer arrangement. The RES Rider includes only costs associated with the build-own-transfer component of this project. This wind energy generation facility will be located in Codington, Deuel and Grant Counties in South Dakota. The project will be built by NextEra, which is the largest developer of wind energy in the United States with more than 12,400 MW of installed wind capacity in the U.S. and Canada. The anticipated commercial operation date for the project is the fourth quarter of 2019. The construction and permitting timeline are consistent with the ability to achieve 100 percent PTC value on the full nameplate capacity proposed by the bidder.

6. Lake Benton

The Lake Benton Wind Farm will have 100.2 MW of nameplate capacity and will be located in Pipestone County southeast of Lake Benton, Minnesota. The project is a repowering of the existing Lake Benton II wind facility that currently contracts its power through a PPA to NSP and has been in operation since May 2000. Like Crowned Ridge, the project will be built by NextEra. The anticipated commerical operation date is fourth quarter 2019. The construction and permitting timeline is consistent with the ability to achieve 100 percent PTC value on the full nameplate capacity. The current PPA will go into suspension at a date to be determined prior to the start of construction on the new facility. Formal decommissioning of the existing facility will occur sometime in early 2019. The existing, higher-priced PPA was set to expire in 2025, so with the proposed repowering build-own-transfer project, we expect to gain at least an additional 19 years of cost-effective generation for the benefit of our customers.

Table 2: Wind Portfolio Projects' Estimated Costs and Commercial Operation Dates

[PROTECTED DATA BEGINS

Project Name	Capital Costs as Presented in Wind RFP Docket	Estimated COD
Blazing Star I		December 2019
Blazing Star II		September 2020
Foxtail		September 2019
Freeborn		December 2020
Crowned Ridge		December 2019
Lake Benton		December 2019

PROTECTED DATA ENDS]

C. Update on Courtenay Wind Project

The Commission's Order in Docket No. E002/M-15-401 authorized recovery of the Courtenay Wind project's actual, prudent costs, not to exceed $300 million, plus associated AFUDC. The Commission's April 11, 2017 Order in our last RES Rider proceeding, Docket No. E002/M-15-805, approved RES Rider recovery of costs related to the Courtenay Wind project. Since the time of our last RES Rider filing, the Courtenay Wind project went into service in December 2016 with a total capital expense of $297.16 million, including AFUDC, which is less than the maximum amount authorized by the Commission in Docket No. E002/M-15-401. Pursuant to the Commission's April 11, 2017 Order, we have included North Dakota investment tax credits (NDITCs) associated with this wind project in our calculation of the revenue requirements; however, the NDITC amount for this project remains $0 for the 2017-2018 period for which we are requesting recovery.

D. REC Sales

On October 15, 2012, Xcel Energy filed a Petition with the Commission seeking approval to share proceeds from the sale of renewable energy credits.[7] The Company proposed to return customers' portion of the proceeds through the Fuel Clause Rider. The Commission's Order in that docket requires the Company to return 100 percent of the proceeds from the sales of RECs to customers through the RES Rider instead of the FCA, though the Order also allows the Company to submit subsequent proposals to share in REC sales proceeds to be reviewed on a case-by-case basis by the Commission.[8]

[7] Docket No. E002/M-12-1132

[8] May 17, 2013 ORDER SETTING PROCEDURES FOR FUTURE PROPOSALS in Docket No. E002/M-12-1132

The Company has completed a number of sales of RECs since we submitted our last RES Rider Petition on September 1, 2015. We have not filed any proposal to share the proceeds from these sales with customers. We therefore propose to refund to customers 100 percent of the proceeds of these transactions.

We have credited to customers a total of $10.6 million in REC sales proceeds in the RES Rider tracker which significantly decreases the total revenue requirements for the 2017 period. The details of each transaction included in the credit are shown in Attachment I.

Attachment I is marked as "Not Public." The REC sales prices are considered to be "not public data" pursuant to Minn. Stat. §13.02, Subd.9, and are "Trade Secret" information pursuant to Minn. Stat. §13.37, subd. 1(b) as this data derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Keeping the final sales prices confidential allows us to continue to be able to negotiate the best price possible for our customers in future REC sales transactions. In addition, we are contractually obligated to maintain as confidential certain sales information.

VI. 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 RES 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 2017 and 2018 RES Rider revenue requirements. The report from Concentric is included as Attachment Q 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. Generation Risk and ROE

Of particular interest to this docket, Concentric includes a discussion of generation risk, which provides additional context for the Commission's consideration when determining an appropriate ROE for this rider. Please see Section VII of the report in Attachment Q.

C. 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 Q 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.

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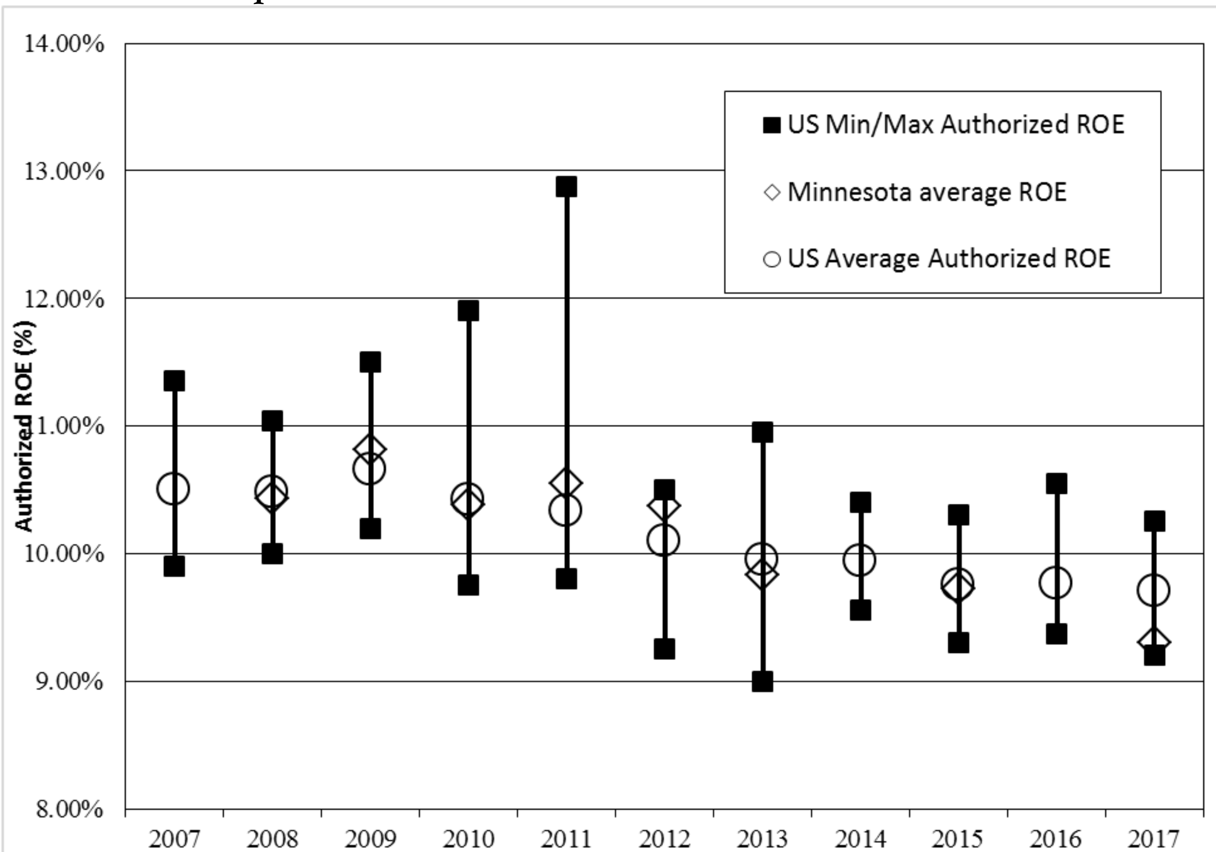
Figure 10 (from Attachment Q)
Comparison of Minnesota and U.S. Authorized Returns



D. 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.

VII. REVENUE REQUIREMENTS AND RES RIDER ADJUSTMENT FACTORS

A. Revenue Requirements Calculation

As approved by the Commission in our most recent prior RES Rider dockets,[9] we propose to allocate costs using the percentage of revenue (interim rates) methodology to determine the percentage factor based on the quotient of the RES Rider cost over the base revenues without fuel, riders, and taxes. The percentage will then be applied to existing base revenues.

We request approval to include -$10.4 million in the RES Rider tracker for 2017 and $10.5 million for 2018. These calculations include:

- costs and expenses associated with the Courtenay Wind project;
- costs and expenses associated with the self-build and build-own-transfer Wind Portfolio projects;
- the true-up of actual PTCs received in 2017 (through September) as compared to the PTCs included in our 2016 rate case test year;
- a forecast of PTCs for the remainder of 2017 and 2018 as compared to the PTCs included in our 2016 test year;
- a credit for customers' share of 100 percent of the proceeds from sales of RECs that occurred between September 2015 and September 2017.

The following table summarizes the various components of the 2017 and 2018 RES Rider revenue requirements.

Table 3: RES Rider Revenue Requirements

	2017	2018
Courtenay Wind Project Expenses	$9,205,625	$6,613,225
Wind Portfolio Project Expenses	$ 396,737	$14,018,917
Net Balance of:		
2017 PTC Balance (Jan.-Sept.)	($7,231,480)	
2017 PTC Forecast (Oct.-Dec.)	($2,012,679)	
2018 PTC Forecast (Jan.-Dec.)		($10,300,043)
REC Sales Proceeds Credit to Customers	($10,552,000)	
ADIT Prorate	$12,229	$136,955
2016 Carryover Balance	$7,190,263	
Revenue Requirement Total	($2,991,306)	$10,469,054
Revenue Collections	$7,348,080	
RES Rider Revenue Requirements	($10,339,386)	$10,469,054

[9] Docket Nos. E002/M-10-1066, E002/M-13-475, E002/M-14-733, E002/M-15-304 and E002/M-15-805

The calculations in support of the proposed RES Adjustment Factor are provided in the following attachments:[10]

Table 4: Attachments

Attachment A	RES Rate Calculation
Attachment B	Annual Tracker Summary
Attachment C	2017 Tracker
Attachment D	2018 Tracker
Attachment E	2019 Tracker
Attachment F	Capital Expenditures
Attachment G	Project Revenue Requirement by Month
Attachment H	Wind PTC Tracker
Attachment I	REC Sales Transaction Details
Attachment J	ADIT Prorate
Attachment K	Sales Forecast
Attachment L	Universal Inputs
Attachment M	Proposed Tariff Sheet (One-Month Negative Rate)
Attachment N	Proposed Tariff Sheet (New On-Going Rate)
Attachment O	2015 PTC Tax Documentation
Attachment P	2016 PTC Tax Documentation
Attachment Q	Concentric Energy Advisors Report on Cost of Equity

1. *2016 True-Up Report*

As a required by the April 11, 2017 Order in our last RES Rider proceeding, the Company updated the RES Rider tracker with actuals through the end of 2016 before implementing a rate to collect the 2016 revenue requirements. The 2016 true-up report was submitted as part of our April 21, 2017 compliance filing in Docket No. E002/M-15-805. Since there have been no changes to the 2016 RES Rider tracker since that time, we have not included the 2016 tracker with this filing.

2. *Allocations to Other Jurisdictions*

The proposed revenue requirements are only those related to the State of Minnesota's retail share of eligible costs. In making our calculations, we used the most current data available and the following allocators:

Interchange Agreement Allocator allocates a share of the total costs to Northern States Power Company-Wisconsin (NSPW) by multiplying total eligible costs by the

[10] The revenue requirements were calculated consistent with past Commission Orders and in accordance with Minn. Stat. § 216B.1645.

Company's currently-effective demand factor under the FERC-approved Interchange Agreement between the Company and NSPW.[11] All investments and expenses received through the RES Rider are billed to NSPW based on demand, per the Interchange Agreement.

Jurisdiction Allocator excludes the portion of Company costs not related to serving Minnesota retail customers by multiplying the Company portion of the total by the Minnesota energy allocation factor. This step allocates a share of costs to the North Dakota and South Dakota retail jurisdictions. We used the energy allocator to allocate the wind project PTCs to each jurisdiction. We used both the energy and the demand allocators to allocate the capital expenses related to the Courtenay Wind project and the Wind Portfolio projects to each jurisdiction.

We have allocated costs incurred in a given year with that same year's allocators to properly align cost causation with cost recovery. The principle of matching a particular year's costs to that year's allocators is consistent with the allocation methodology approved in past RES Rider dockets.[12]

While we have calculated the revenue requirements in this Petition using forecasted allocators for 2017 and 2018, we propose to true-up the tracker account to the actual allocators when they become available. The actual allocators used to true-up the tracker will be consistent with the allocators used to allocate variable costs (including PTCs) to the Minnesota jurisdiction in our annual jurisdictional reports filed on May 1 each year.

Attachment L provides the Universal Inputs for detailed allocator percentages.

3. PTC Forecast

Included in the costs associated with certain renewable facilities are production tax credits. The Commission's May 18, 2015 Order in Docket No. E002/GR-13-868 allows the Company to true-up the forecasted PTC amount included in base rates to the actual PTC amount and incorporate the difference in the RES Rider tracker.

We estimate PTC benefits based on expected energy production. The Grand Meadow, Nobles, Border Winds, Pleasant Valley, and Courtenay wind projects are

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[11] The 2017 Interchange Agreement allocation was accepted by FERC via its letter order dated May 26, 2017 in Docket No. ER17-1377.

[12] The most recent examples are Docket Nos. E002/M-10-1066, E002/M-13-475, E002/M-14-733, E002/M-15-304 and E002/M-15-805.

currently eligible for PTCs. The Wind Portfolio projects will be eligible for PTCs as each goes into service in 2019 and 2020.

The PTC forecast was updated in the Company's most recent electric rate case, which was approved by the Commission in its June 12, 2017 Order in Docket No. E002/GR-15-826.[13] The PTC level was calculated by multiplying the expected kWh generated by the effective per kWh credit at that time. This filing trues up the PTCs based on actual wind generation for January through September 2017 to the PTCs included in base rates. We include the forecasted PTCs for October through December 2017 and the forecasted PTCs for 2018 which will be trued up in our next RES Rider filing. At that time we will also true up the January through September 2017 PTCs for the actual 2017 jurisdictional energy allocator.

The actual and forecasted PTCs for 2017 and 2018 exceed the base rate PTC level resulting in a credit recorded on the tracker of $9.2 million and $10.3 million, respectively. Please see Attachment H for further details.

The Commission's June 1, 2015 Order in Docket No. E002/M-15-304 required the Company to submit 2014 tax documentation verifying our 2014 production tax credits in our 2015 RES filing. We provided the 2014 tax documentation in our September 9, 2015 Second Revised Petition filed in Docket No. E002/M-15-805. We provide the 2015 and 2016 tax documentation verifying our 2015 and 2016 production tax credits as Attachments O and P to this Petition. The PTC values in this tax documentation tie to the PTC values provided in our April 21, 2017 compliance filing in Docket No. E002/M-15-805. We will provide the 2017 and 2018 tax documentation in future RES filings when they are available.

4. CWIP and AFUDC

Our calculations include recovery of a current return on the Construction Work in Progress (CWIP) balance in lieu of future recovery of an Allowance for Funds Used During Construction (AFUDC).

The revenue requirement model includes a current return on capital expenditures beginning with the cumulative CWIP balance for the Courtenay project per our requested eligibility date of September 1, 2015 and for the self-build Wind Portfolio per our requested eligibility date of September 1, 2017.[14] The beginning CWIP

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[13] See Schedule 19 of the Direct Testimony of Company Witness Ms. Anne E. Heuer, Exhibit___(AEH-1).
[14] The Order in the Wind RFP docket was issued on September 1, 2017. Dollars were not spent prior to that date.

balance includes AFUDC incurred prior to the eligibility date. After that date, the Minnesota jurisdictional portion of costs does not include AFUDC, and a current return is calculated on the CWIP balance. The costs included in this adjustment mechanism will not be recovered from customers under any other mechanism.

We note that other NSP jurisdictions do not provide for the same ratemaking treatment of CWIP as provided in the Minnesota jurisdiction. To ensure appropriate allocation to all jurisdictions, we use the traditional method of calculating AFUDC at the total Company level. However, beginning with the eligibility date for each project, we offset total Minnesota Company AFUDC in an amount equal to the AFUDC related to the State of Minnesota retail jurisdiction. This offset, in effect, reduces the amount of AFUDC leaving only the portion that would be allocated to non-Minnesota jurisdictions. In this way, we ensure that costs are appropriately assigned to each jurisdiction, pursuant to their specific ratemaking procedures.

5. Accumulated Deferred Income Taxes

Ordering Point No. 2 of the Commission's April 11, 2017 Order in Docket No. E002/M-15-805 defers any final decision regarding the need to prorate accumulated deferred income tax balances and true-ups and required the Company to address this matter in its next RES Rider filing. Since this Order was issued, 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.[15] 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).[16] 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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[15] Actual ADIT for the 2016 historic year was included in our April 21, 2017 compliance filing in our last RES Rider proceeding.
[16] 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 Minnesota electric rate case are shown on Attachments G and L and have been used to determine the return on CWIP and rate base. Allowable costs include the overall rate of return on investments, O&M expenses, property taxes, current and deferred taxes, and book depreciation.

7. Depreciation

The remaining life assumptions used in this filing are consistent with the most recently approved remaining life filing.[17] The Company assumes a depreciable life of 25 years for the Courtenay Wind Farm and the Wind Portfolio projects as that is the standard depreciation the Company assigns to wind assets. If any changes are made to the Courtenay Wind Farm or the Wind Portfolio projects' remaining lives in future Commission Orders, those changes will be reflected in future RES Rider filings.

8. Internal Labor Removal

Consistent with Commission precedent, we have excluded internal labor costs from the Courtenay project and the Wind Portfolio projects included in this filing.

9 Additional Information

The Commission's March 20, 2008 Order in Docket No. E002/M-07-872 stipulated that only incremental costs not recovered elsewhere in Xcel Energy's rates are allowed to flow through the rider.[18] We confirm that our revenue requirements for 2017 and 2018 include only incremental costs not recovered elsewhere in our rates. Costs recovered via the RES Rider are not included in base rates since the Courtenay Wind project and the Wind Portfolio projects were not included in the 2016 through 2019 test years used in our recently approved Minnesota electric multi-year rate case.

B. RES Rider True-up Report

Similar to other rate adjustment mechanisms, this Rider uses a tracker account as the accounting mechanism. Each month as PTCs are generated, the Company tracks the amount of recovery under the RES Rider Adjustment Factor compared to the amount

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[17] November 13, 2015 Order in Docket No. E,G002/D-15-46. The Company's most recent Petition to update remaining lives was orally approved by the Commission during its hearing on October 24, 2017 in Docket No. E,G002/D-17-147.
[18] Ordering Paragraph Number 2(a).

included in base rates. Each month as revenues are collected from retail customers, the Company tracks the amount of recovery under the RES rate adjustment and compares that amount with the actual costs including a return on investments, depreciation expense, federal and state income taxes, production taxes, O&M expenses and royalty payments. The under-recovered amounts are recorded in FERC Account 182.3, Other Regulatory Assets, and the over-recovered amounts are recorded in FERC Account 254, Other Regulatory Liabilities. Any over- or under-recovery balance from the prior year is used in the calculation of the RES Adjustment Factor.

Per Commission Order dated March 20, 2008 in Docket No. E002/M-07-872:

> *…Xcel is to provide, in subsequent filings, the amount collected from retail customers and the actual costs including a return on investment, depreciation expense, federal and state income taxes, production taxes, operation and maintenance expenses, royalty payments, and production tax credits.*[19]

The amount collected from retail customers and PTCs are included in Attachment H. Attachment B is the RES Rider Tracker.

C. Calculation of the RES Adjustment Factors and Rate Implementation Plan

Attachment A shows two RES Rider Adjustment Factors to be implemented. The first shows an Adjustment Factor calculated to apply a one-month credit to customers' bills beginning February 1, 2018 as follows:

All Classes	-6.384%

This one-time credit refunds to customers the over-collection of 2017 revenue requirements. Implementation of this factor results in an average one-time refund of $4.40 for a typical residential customer using 675 kWh per month.

The second Adjustment Factor presented on Attachment A is calculated to apply a new charge to customers' bills beginning March 1, 2018 as follows:

All Classes	0.497%

[19] Ordering Paragraph Number 2(d).

This Adjustment Factor is calculated to collect the 2018 revenue requirements over the remaining ten months of 2018. Implementation of this factor results in an average bill impact of $0.36 per month for a typical residential customer using 675 kWh per month.

We propose to implement separate rates for each rider tracker year for two main reasons. First, the one-time credit will allow a more timely refund to the customers who were charged the RES Rider rate in 2017. If the refund is done in one billing period, the refund should more closely match to the 2017 customers charged the RES Rider rate. If the credit is spread out over a longer period of time, there is greater mismatch in the customer population, and customers will wait longer to receive the credit.

Second, implementing the second on-going rate serves as a rate smoothing mechanism. Beginning in 2019, as the Wind Portfolio project construction begins in earnest and project in-servicing begins, the RES Rider revenue requirements are forecasted to increase.[20] We predict that this will still be the case even with some amount of not-yet-known additional PTC and REC sales off-sets. We propose this approach to smooth the changes in rates between 2017 and 2019by issuing the credit for 2017 to restore balance to the tracker and then implementing a 2018 rate. The step between the 2018 rate and the future 2019 rate will be smoothed.

Should the Commission approve this Petition after February 1, 2018, we propose to recalculate the Adjustment Factors for implementation in compliance based on the timing of the Commission's decision.

XIII. PROPOSED TARIFF SHEET AND CUSTOMER NOTICE

A. Revised Tariff Sheet

We provide redline and clean revisions to the RES Rider tariff sheet, Sheet No. 5-147 reflecting the two rates we propose to implement. Attachment M shows our proposed one-month Adjustment Factor of -6.384 percent to be implemented on February 1, 2018. Attachment N shows our proposed rate of 0.497 percent to be implemented on March 1, 2018 after the one-month refund is completed. We will update the tariff sheet to reflect the actual adjustment factor to be implemented based on the Commission's decisions in this proceeding and will provide an updated final tariff sheet in a compliance filing within 10 days after the Order is received.

[20] See the Annual Tracker in Attachment B for the 2019 forecast.

B. Customer Notification

The Company proposes to provide the below message to customers as a notice on their February 2018 electric bills. This message is consistent with the message presented in compliance with the Commission's Order in Docket No. E002/M-15-304, which was the last RES Rider where we implemented a one-month negative rate.

> *For this month only, the Resource Adjustment has decreased due to changes in the Renewable Energy Standard (RES) Rider which recovers our investments and expenses to add renewable energy systems to our generation resources. To return excess collections, the RES Rider portion of the Resource Adjustment is negative 6.384% of these charges on your bill: basic service charge, energy charge, and demand charge.*

In March 2018 bills, we propose the following message be included in customer bills:

> *This month the Resource Adjustment has increased due to changes in the Renewable Energy Standard Rider, which recovers our investments and expenses to add renewable energy systems to our generation resources. The RES Rider portion of the Resource Adjustment is 0.497% of these charges on your bill: basic service charge, energy charge, and demand charge.*

Consistent with past practice, we will work with the Department of Commerce and the Commission Staff regarding our proposed customer notices.

CONCLUSION

Xcel Energy respectfully requests the Commission approve:

- rider eligibility of the new self-build and build-own-transfer Wind Portfolio projects;
- the 2017 revenue requirements of -$10.4 million;
- the 2018 revenue requirements of $10.5 million;
- the proposed electric rider ROE of 10.00% used to calculate the revenue requirements;
- the two proposed RES Rider Adjustment Factor calculations adjusted for the timing of the Commission's decision:
  - a one-month Adjustment Factor of -6.384% to refund the over-collection of 2017 revenue requirements in February 2018 and
  - a new rate of 0.497% to collect the 2018 revenue requirements over the remainder of 2018 beginning in March 2018; and
- the proposed tariff revisions and customer notices.

The Company plans to continue pursuing investments in renewable energy generation projects and appreciates the interest and efforts of state policy makers in supporting this effort.

Dated: November 17, 2017

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE RENEWABLE ENERGY STANDARD RIDER REVENUE REQUIREMENTS FOR 2017 & 2018 AND REVISED ADJUSTMENT FACTORS

DOCKET NO. E002/M-17-____

PETITION

SUMMARY OF FILING

Please take notice that on November 17, 2017 Northern States Power Company, doing business as Xcel Energy, submitted to the Minnesota Public Utilities Commission a Petition for approval of our Renewable Energy Standard (RES) Rider revenue requirements for 2017 and 2018 and a proposed plan to implement the RES Adjustment Factor.

RES Rate Rider Petition Attachments
Table of Contents

Line No.	RES Rate - 2017		Reference
1	2017 Revenue Requirements	($10,339,386)	*Att. C*
2			
3	Forecasted Feb 2018 Base Revenues	161,952,650	*Att. K*
4			
5	RES Refund Rate (Feb 2018) [1]	-6.384%	
6			
7			
8	**RES Rate - 2018**		*Reference*
9			
10	2018 Revenue Requirements	$10,469,054	*Att. D*
11	Less Forecasted Revenues at current rate (Jan 2018)	($921,709)	*Att. D*
12	Remaining 2018 Revenue Requirements	$9,547,345	
13			
14	Forecasted Mar-Dec 2018 Base Revenues	1,920,349,934	*Att. K*
15			
16	RES Rate (Mar-Dec 2018) [1]	0.497%	

[1] Note the rates shown above assume:
a) a percent factor based on currently forecasted base revenues,
b) revenues forecasted for January 2018 at the currently authorized rate,
c) a one-time rate refund in February 2018 for the current 2017 over-collection balance, and
d) a proposed new rate effective March 2018 to recover the remainder of the 2018 revenue requirements over the remainder of the year (10 months)

Annual Tracker Summary				
Amounts in $ Dollars	**2017**	**2018**	**2019**	
	Att. C	*Att. D*	*Att. E*	*Reference*
Wind Projects:				
Courtenay Wind	9,205,625	6,613,225	5,074,110	*Att. G, pg. 7-9*
Blazing Star I (Self-build)	25,540	3,087,998	13,619,105	*Att. G, pg. 1-3*
Blazing Star II (Self-build)	18,612	1,046,889	5,986,340	*Att. G, pg. 4-6*
Foxtail (Self-build)	277,045	4,328,205	10,794,216	*Att. G, pg. 16-18*
Freeborn (Self-build)	29,223	796,626	1,940,502	*Att. G, pg. 19-21*
Crowned Ridge (BOT)	41,145	3,410,594	9,187,031	*Att. G, pg. 10-12*
Lake Benton (BOT)	5,173	1,348,605	3,609,165	*Att. G, pg. 22-24*
Wind Projects Total	9,602,361	20,632,142	50,210,470	
RES PTC Tracker	(9,244,159)	(10,300,043)	(10,288,691)	*Att. H*
REC Sales Credit	(10,552,000)	-	-	*Att. I*
ADIT Prorate	12,229	136,955	3,639,723	*Att. J*
Revenue Requirement Subtotal	(10,181,569)	10,469,054	43,561,502	
Carryover Balance	7,190,263	-	(0)	
Revenue Requirement Total	**(2,991,306)**	**10,469,054**	**43,561,502**	
Revenue Collections	7,348,080	10,469,054	43,561,502	
Balance	(10,339,386)	-	-	

Northern States Power Company
State of Minnesota
Renewable Energy Standard Rider (RES)

Line No.	2017 Tracker *Amounts in $ Dollars*	Carryover	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Annual Total	Reference
			Actual	*Actual*	*Actual*	*Actual*	*Actual*	*Actual*	*Actual*	*Actual*	*Actual*	*Forecast*	*Forecast*	*Forecast*		
1	Wind Projects:															
2	Courtenay Wind		457,446	690,313	431,756	1,467,046	(25,088)	941,100	1,466,149	1,443,530	706,088	442,535	576,502	608,247	9,205,625	*Att. G, pg. 7-9*
3	Blazing Star I (Self-build)		(439)	(437)	(434)	(432)	(430)	(427)	(425)	(422)	(420)	5,373	11,617	12,417	25,540	*Att. G, pg. 1-3*
4	Blazing Star II (Self-build)		(320)	(318)	(317)	(315)	(313)	(311)	(310)	(308)	(306)	3,996	8,526	8,908	18,612	*Att. G, pg. 4-6*
5	Foxtail (Self-build)		(4,760)	(4,734)	(4,708)	(4,682)	(4,656)	(4,629)	(4,603)	(4,577)	(4,551)	9,821	89,904	219,220	277,045	*Att. G, pg. 16-18*
6	Freeborn (Self-build)		(503)	(500)	(497)	(494)	(492)	(489)	(486)	(483)	(481)	5,767	12,419	15,460	29,223	*Att. G, pg. 19-21*
7	Crowned Ridge (BOT)		(708)	(704)	(700)	(696)	(692)	(688)	(684)	(681)	(677)	9,160	19,053	19,161	41,145	*Att. G, pg. 10-12*
8	Lake Benton (BOT)		(89)	(88)	(88)	(88)	(87)	(87)	(86)	(86)	(85)	1,130	2,381	2,445	5,173	*Att. G, pg. 22-24*
9	Wind Projects Total		450,626	683,531	425,012	1,460,339	(31,758)	934,469	1,459,555	1,436,973	699,569	477,782	720,403	885,859	9,602,361	
10																
11	RES PTC Tracker		542,882	(2,384,098)	(2,051,591)	(588,749)	13,255	(829,146)	25,100	(454,334)	(1,504,798)	(329,541)	(944,106)	(739,033)	(9,244,159)	*Att. H*
12	REC Sales Credit		(4,912,560)	-	-	-	-	-	(5,639,440)	-	-	-	-	-	(10,552,000)	*Att. I*
13	ADIT Prorate		-	-	-	-	-	-	-	-	-	7,981	4,119	129	12,229	*Att. J*
14																
15	**Revenue Requirement Subtotal**		**(3,919,051)**	**(1,700,566)**	**(1,626,579)**	**871,591**	**(18,503)**	**105,322**	**(4,154,785)**	**982,639**	**(805,229)**	**156,222**	**(219,584)**	**146,954**	**(10,181,569)**	
16																
17	Carryover Balance	7,190,263	599,189	599,189	599,189	599,189	599,189	599,189	599,189	599,189	599,189	599,189	599,189	599,189	7,190,263	
18																
19	**Revenue Requirement Total**		**(3,319,863)**	**(1,101,378)**	**(1,027,390)**	**1,470,779**	**580,686**	**704,511**	**(3,555,597)**	**1,581,828**	**(206,040)**	**755,411**	**379,605**	**746,143**	**(2,991,306)**	
20	Revenue Collections		1	141	1	1	779,779	973,561	1,090,352	986,550	986,602	840,721	805,704	884,666	7,348,080	
21	Balance		(3,319,863)	(4,421,382)	(5,448,773)	(3,977,995)	(4,177,089)	(4,446,139)	(9,092,087)	(8,496,810)	(9,689,453)	(9,774,763)	(10,200,862)	(10,339,386)		

Northern States Power Company
State of Minnesota
Renewable Energy Standard Rider (RES)

2018 Tracker

Line No.	*Amounts in $ Dollars*	Carryover	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 Total	
			Forecast	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*		*Reference*
1	Wind Projects:															
2	Courtenay Wind		314,655	783,712	252,599	141,127	553,742	784,496	1,196,254	1,121,841	558,818	198,623	350,899	356,459	6,613,225	*Att. G, pg. 7-9*
3	Blazing Star I (Self-build)		(41,486)	60,467	162,615	163,869	165,283	208,853	252,612	272,011	291,659	417,933	558,368	575,815	3,087,998	*Att. G, pg. 1-3*
4	Blazing Star II (Self-build)		(9,222)	(9,006)	(7,393)	6,634	19,350	19,678	35,074	130,747	212,158	214,516	216,627	217,725	1,046,889	*Att. G, pg. 4-6*
5	Foxtail (Self-build)		226,108	244,870	244,994	245,248	246,714	267,046	303,530	352,887	429,419	510,961	565,418	691,010	4,328,205	*Att. G, pg. 16-18*
6	Freeborn (Self-build)		4,630	4,977	5,313	5,653	6,063	60,976	116,088	116,988	117,825	118,606	119,390	120,117	796,626	*Att. G, pg. 19-21*
7	Crowned Ridge (BOT)		70,114	181,865	182,443	183,044	183,672	284,525	385,451	386,255	387,061	387,879	388,721	389,565	3,410,594	*Att. G, pg. 10-12*
8	Lake Benton (BOT)		25,332	72,457	72,718	72,994	73,287	112,705	152,157	152,539	152,936	153,365	153,823	154,291	1,348,605	*Att. G, pg. 22-24*
9	Wind Projects Total		590,132	1,339,342	913,289	818,570	1,248,111	1,738,280	2,441,166	2,533,268	2,149,874	2,001,883	2,353,245	2,504,983	20,632,142	
10																
11	RES PTC Tracker		(341,269)	(1,115,230)	(1,987,549)	(1,884,466)	(177,587)	(650,479)	(25,060)	(744,669)	(1,506,687)	(325,832)	(816,509)	(724,708)	(10,300,043)	*Att. H*
12	REC Sales Credit		-	-	-	-	-	-	-	-	-	-	-	-	-	*Att. I*
13	ADIT Prorate		22,612	20,722	18,630	16,605	14,512	12,487	10,395	8,302	6,277	4,185	2,160	67	136,955	*Att. J*
14																
15	**Revenue Requirement Subtotal**		**271,474**	**244,834**	**(1,055,630)**	**(1,049,292)**	**1,085,036**	**1,100,288**	**2,426,502**	**1,796,901**	**649,465**	**1,680,236**	**1,538,897**	**1,780,343**	**10,469,054**	
16																
17	Carryover Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
18																
19	**Revenue Requirement Total**		**271,474**	**244,834**	**(1,055,630)**	**(1,049,292)**	**1,085,036**	**1,100,288**	**2,426,502**	**1,796,901**	**649,465**	**1,680,236**	**1,538,897**	**1,780,343**	**10,469,054**	*Att. A*
20	Revenue Collections		921,709	-	923,266	810,589	895,728	990,294	1,140,337	1,105,543	951,659	905,601	868,234	956,094	10,469,054	
21	Balance		(650,235)	(405,401)	(2,384,297)	(4,244,178)	(4,054,870)	(3,944,876)	(2,658,712)	(1,967,353)	(2,269,547)	(1,494,912)	(824,249)	(0)		

2019 Tracker

Line No.	*Amounts in $ Dollars*	Carryover	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 Total	Reference
			Forecast	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*		*Reference*
1	Wind Projects:															
2	Courtenay Wind		172,779	644,092	115,696	6,748	421,645	654,766	1,068,807	996,901	436,609	79,053	235,253	241,761	5,074,110	*Att. G, pg. 7-9*
3	Blazing Star I (Self-build)		413,577	420,454	545,227	743,830	838,875	1,005,630	1,294,726	1,604,457	1,926,093	2,135,426	2,207,629	483,183	13,619,105	*Att. G, pg. 1-3*
4	Blazing Star II (Self-build)		117,177	147,820	179,494	208,423	241,440	310,706	433,086	580,366	710,368	899,251	1,068,264	1,089,945	5,986,340	*Att. G, pg. 4-6*
5	Foxtail (Self-build)		615,305	604,817	594,788	577,181	648,426	801,039	967,934	1,173,832	1,396,828	1,537,710	1,578,836	297,522	10,794,216	*Att. G, pg. 16-18*
6	Freeborn (Self-build)		99,141	100,013	100,830	101,653	102,546	105,005	107,749	110,646	113,739	242,938	374,759	381,485	1,940,502	*Att. G, pg. 19-21*
7	Crowned Ridge (BOT)		91,333	48,273	5,694	(36,383)	3,377	43,161	68,002	490,285	1,239,716	2,778,556	3,888,330	566,687	9,187,031	*Att. G, pg. 10-12*
8	Lake Benton (BOT)		49,779	35,215	21,035	7,251	25,446	43,639	56,014	218,318	483,600	1,014,188	1,401,502	253,178	3,609,165	*Att. G, pg. 22-24*
9	Wind Projects Total		1,559,091	2,000,683	1,562,764	1,608,701	2,281,754	2,963,944	3,996,320	5,174,805	6,306,953	8,687,122	10,754,572	3,313,761	50,210,470	
10																
11	RES PTC Tracker		(560,672)	(949,073)	(1,834,935)	(1,687,104)	(285,813)	(673,799)	(134,294)	(807,076)	(1,421,329)	(365,177)	(831,789)	(737,629)	(10,288,691)	*Att. H*
12	REC Sales Credit		-	-	-	-	-	-	-	-	-	-	-	-	-	*Att. I*
13	ADIT Prorate		600,940	550,712	495,103	441,287	385,678	331,862	276,253	220,644	166,828	111,219	57,403	1,794	3,639,723	*Att. J*
14																
15	**Revenue Requirement Subtotal**		**1,599,358**	**1,602,322**	**222,931**	**362,885**	**2,381,619**	**2,622,008**	**4,138,279**	**4,588,373**	**5,052,452**	**8,433,164**	**9,980,186**	**2,577,925**	**43,561,502**	
16																
17	Carryover Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
18																
19	**Revenue Requirement Total**		**1,599,358**	**1,602,322**	**222,931**	**362,885**	**2,381,619**	**2,622,008**	**4,138,279**	**4,588,373**	**5,052,452**	**8,433,164**	**9,980,186**	**2,577,925**	**43,561,502**	
20	Revenue Collections		1,599,358	1,602,322	222,931	362,885	2,381,619	2,622,008	4,138,279	4,588,373	5,052,452	8,433,164	9,980,186	2,577,925	43,561,502	
21	Balance		-	-	-	-	-	-	-	-	-	-	-	-		

Northern States Power Company
State of Minnesota
Renewable Energy Standard Rider (RES)
Capital Expenditures

	Amounts in $ Dollars			AFUDC Pre-eligible	CWIP EXPENDITURES (excluding Internal Labor)						
Line No.					2015	2016	2017	2018	2019	2020	Total
1	Blazing Star I	Capital	A.0001701.001-G100-Blazing Star I Wind Farm				1,546,092	56,374,979	239,403,100		297,324,172
2	Blazing Star I	Capital	A.0001701.002-G100-Blazing Star I Wind Farm Land					283,803	71,155		354,958
3	Blazing Star I	Capital	A.0001701.004 G100-Blazing Star I Wind Farm TSG S						11,019,722		11,019,722
4	Blazing Star I	Capital	A.0001701.005 G100-Blazing Star I Wind Farm Tline				33,556	17,015,126	9,662,800		26,711,481
5			**Sub-Total Blazing Star I**				**1,579,648**	**73,673,908**	**260,156,777**		**335,410,333**
6											
7	Blazing Star II	Capital	A.0001702.001-G100-Blazing Star II Wind Farm				1,122,357	21,114,691	79,471,767	188,251,494	289,960,309
8	Blazing Star II	Capital	A.0001702.002-G100-Blazing Star II Wind Farm Land						58,428		58,428
9	Blazing Star II	Capital	A.0001702.003-G100-Blazing Star II Wind Farm TSG							4,831,400	4,831,400
10	Blazing Star II	Capital	A.0001702.004-G100-Blazing Star II Wind Farm TSG						5,170,637	7,003,838	12,174,475
11	Blazing Star II	Capital	A.0001702.005 G100-Blazing Star II Wind Farm Tlin					5,916,000	32,340,800		38,256,800
12			**Sub-Total Blazing Star II**				**1,122,357**	**27,030,691**	**117,041,632**	**200,086,732**	**345,281,412**
13											
14	Courtenay Wind	Capital	A.0001580.001 CRT0C Courtenay Wind Farm Cons	140,596	95,924,998	169,433,906	880,575				266,380,076
15	Courtenay Wind	Capital	A.0001580.002 CRT0C Courtenay Wind Xmsn Serv		32,461	8,683,727	(761,856)				7,954,332
16	Courtenay Wind	Capital	A.0001580.003 CRT0C Courtenay Wind Collector		5	7,968,579	(119,139)				7,849,446
17	Courtenay Wind	Capital	A.0001580.025 CRT0C Courtenay Wind Land		440,555	1,647,779	(4,365)				2,083,969
18			**Sub-Total Courtenay Wind**	**140,596**	**96,398,020**	**187,733,992**	**(4,785)**				**284,267,823**
19											
20	Crowned Ridge	Capital	A.0001705.001-G100-Crowned Ridge BOT Wind Farm				2,382,705	50,978,472	426,770,520	991,817	481,123,515
21			**Sub-Total Crowned Ridge**				**2,382,705**	**50,978,472**	**426,770,520**	**991,817**	**481,123,515**
22											
23	Foxtail	Capital	A.0001703.001-FOX G100-Foxtail Wind Farm				18,853,369	64,638,030	149,632,123		233,123,522
24	Foxtail	Capital	A.0001703.002 FOX G100-Foxtail Wind Farm Land					40,477	144,015		184,492
25	Foxtail	Capital	A.0001703.003 FOX G100-Foxtail Wind Farm TSG 230					295,801			295,801
26	Foxtail	Capital	A.0001703.004 FOX G100-Foxtail Wind Farm TSG Sub					6,422,780	25,883		6,448,664
27	Foxtail	Capital	A.0001703.005 FOX G100-Foxtail Wind Farm 230 Line				15,616,860				15,616,860
28			**Sub-Total Foxtail**				**34,470,229**	**71,397,088**	**149,802,022**		**255,669,339**
29											
30	Freeborn	Capital	A.0001704.001-G100-Freeborn Wind Farm				2,226,529	13,533,735	33,045,774	249,793,333	298,599,371
31	Freeborn	Capital	A.0001704.002-G100-Freeborn Wind Farm Land					250,622	118,320		368,942
32	Freeborn	Capital	A.0001704.003-G100-Freeborn Wind Farm TSG Tline							2,218,500	2,218,500
33	Freeborn	Capital	A.0001704.004-G100-Freeborn Wind Farm TSG Sub						241,915	10,815,619	11,057,534
34			**Sub-Total Freeborn**				**2,226,529**	**13,784,358**	**33,406,009**	**262,827,452**	**312,244,348**
35											
36	Lake Benton	Capital	A.0001706.001-G100-Lake Benton BOT Wind Farm				306,704	20,833,504	145,404,926	991,817	167,536,951
37			**Sub-Total Lake Benton**				**306,704**	**20,833,504**	**145,404,926**	**991,817**	**167,536,951**
38											
39			**Total**	**140,596**	**96,398,020**	**187,733,992**	**42,083,387**	**257,698,021**	**1,132,581,887**	**464,897,819**	**2,181,533,721**

Line No.	NSPM Rider Revenue Requirements calculation - MN RES *Amounts in $ Dollars*	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	2017
	Blazing Star I													
2	**Cap Structure and Tax Rates**													
3	LT Debt Cost	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%
4	LT Debt Ratio	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%
5	LT Debt Weighted Cost Rounded	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%
6	ST Debt Cost	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%
7	ST Debt Ratio	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%
8	ST Debt Weighted Cost Rounded	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
9	Equity Cost	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
10	Equity Ratio	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%
11	Equity Weighted Cost Rounded	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%
12														
13	Fed Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
14	State Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
15	State Composite Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
16														
17	**Revenue Requirement Calculation**													
18	CWIP										1,389,710	1,497,586	1,579,648	1,579,648
19	Plant Investment													
20	Depreciation Reserve													
21	Accumulated Deferred Taxes	(351)	(702)	(1,053)	(1,403)	(1,754)	(2,105)	(2,456)	(2,807)	(3,158)	(3,508)	(3,859)	(4,210)	(4,210)
22	Rate Base	351	702	1,053	1,403	1,754	2,105	2,456	2,807	3,158	1,393,218	1,501,445	1,583,858	1,583,858
23	Rate Base from Previous Period		351	702	1,053	1,403	1,754	2,105	2,456	2,807	3,158	1,393,218	1,501,445	1,501,445
24	Average Rate Base	175	526	877	1,228	1,579	1,930	2,280	2,631	2,982	698,188	1,447,332	1,542,652	1,542,652
25														
26	LT Debt Return	0	1	2	2	3	4	4	5	5	1,286	2,666	2,841	6,819
27	ST Debt Return	0	0	0	0	0	0	0	0	0	29	60	64	154
28	Equity Return	1	2	4	5	7	8	10	12	13	3,055	6,332	6,749	16,198
29														
30	Tax Depreciation & Removal													
31	Avoided Tax Interest										1,943	4,043	4,320	10,307
32	Book Depreciation													
33	AFUDC													
34														
35	Annual Deferred Tax	(351)	(351)	(351)	(351)	(351)	(351)	(351)	(351)	(351)	(351)	(351)	(351)	(4,210)
36	Operating Expense													
37	Property Tax Expense													
38														
39	Current Income Tax Requirement	(247)	(246)	(245)	(244)	(243)	(242)	(241)	(239)	(238)	3,279	7,073	7,563	15,731
40	Production Tax Credit													
41														
42	**Total Revenue Requirements**	(597)	(593)	(590)	(587)	(584)	(580)	(577)	(574)	(571)	7,298	15,780	16,867	34,692
43														
44	Jurisdictional Allocation Factor *	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%
45	Interchange Allocation Factor	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%
46	**State Jurisdictional Revenue Requirement**	(439)	(437)	(434)	(432)	(430)	(427)	(425)	(422)	(420)	5,373	11,617	12,417	25,540

* Note: State Jurisdictional Requirements are calculated using Energy and Demand allocators applied to the separate Production and Transmission components of the project.

Line No.	NSPM Rider Revenue Requirements calculation - MN RES *Amounts in $ Dollars*	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	2018
	Blazing Star I													
2	**Cap Structure and Tax Rates**													
3	LT Debt Cost	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%
4	LT Debt Ratio	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%
5	LT Debt Weighted Cost Rounded	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%
6	ST Debt Cost	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%
7	ST Debt Ratio	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%
8	ST Debt Weighted Cost Rounded	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
9	Equity Cost	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
10	Equity Ratio	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%
11	Equity Weighted Cost Rounded	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%
12														
13	Fed Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
14	State Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
15	State Composite Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
16														
17	**Revenue Requirement Calculation**													
18	CWIP	1,641,091	25,966,766	26,065,652	26,174,489	26,311,880	36,511,849	36,688,872	41,052,574	41,286,616	71,216,787	74,826,105	75,253,556	75,253,556
19	Plant Investment													
20	Depreciation Reserve													
21	Accumulated Deferred Taxes	(48,279)	(92,347)	(136,416)	(180,484)	(224,553)	(268,621)	(312,690)	(356,759)	(400,827)	(444,896)	(488,964)	(533,033)	(533,033)
22	Rate Base	1,689,370	26,059,113	26,202,068	26,354,973	26,536,433	36,780,471	37,001,562	41,409,333	41,687,443	71,661,683	75,315,070	75,786,589	75,786,589
23	Rate Base from Previous Period	1,583,858	1,689,370	26,059,113	26,202,068	26,354,973	26,536,433	36,780,471	37,001,562	41,409,333	41,687,443	71,661,683	75,315,070	75,315,070
24	Average Rate Base	1,636,614	13,874,241	26,130,590	26,278,521	26,445,703	31,658,452	36,891,016	39,205,447	41,548,388	56,674,563	73,488,376	75,550,829	75,550,829
25														
26	LT Debt Return	3,014	25,552	48,124	48,396	48,704	58,304	67,941	72,203	76,518	104,376	135,341	139,139	827,613
27	ST Debt Return	68	578	1,089	1,095	1,102	1,319	1,537	1,634	1,731	2,361	3,062	3,148	18,724
28	Equity Return	7,160	60,700	114,321	114,969	115,700	138,506	161,398	171,524	181,774	247,951	321,512	330,535	1,966,049
29														
30	Tax Depreciation & Removal													
31	Avoided Tax Interest	4,673	39,697	74,849	75,313	75,834	90,905	106,078	112,878	119,782	163,568	212,345	218,727	1,294,649
32	Book Depreciation													
33	AFUDC													
34														
35	Annual Deferred Tax	(44,069)	(44,069)	(44,069)	(44,069)	(44,069)	(44,069)	(44,069)	(44,069)	(44,069)	(44,069)	(44,069)	(44,069)	(528,823)
36	Operating Expense													
37	Property Tax Expense													
38														
39	Current Income Tax Requirement	(22,745)	39,746	102,385	103,170	104,053	130,780	157,639	169,582	181,686	259,277	345,600	356,470	1,927,643
40	Production Tax Credit													
41														
42	**Total Revenue Requirements**	(56,571)	82,507	221,851	223,561	225,491	284,840	344,447	370,874	397,641	569,897	761,446	785,224	4,211,207
43														
44	Jurisdictional Allocation Factor *	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%
45	Interchange Allocation Factor	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%
46	**State Jurisdictional Revenue Requirement**	(41,486)	60,467	162,615	163,869	165,283	208,853	252,612	272,011	291,659	417,933	558,368	575,815	3,087,998

* Note: State Jurisdictional Requirements are calculated using Energy and Demand allocators applied to the separate Production and Transmission components of the project.

Line No.	NSPM Rider Revenue Requirements calculation - MN RES *Amounts in $ Dollars*	Jan - 2019	Feb - 2019	Mar - 2019	Apr - 2019	May - 2019	Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	2019
	Blazing Star I													
2	**Cap Structure and Tax Rates**													
3	LT Debt Cost	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%
4	LT Debt Ratio	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%
5	LT Debt Weighted Cost Rounded	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%
6	ST Debt Cost	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%
7	ST Debt Ratio	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%
8	ST Debt Weighted Cost Rounded	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%
9	Equity Cost	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
10	Equity Ratio	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%
11	Equity Weighted Cost Rounded	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%
12														
13	Fed Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
14	State Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
15	State Composite Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
16														
17	**Revenue Requirement Calculation**													
18	CWIP	81,985,578	83,919,862	118,711,452	109,983,858	120,385,744	156,170,935	196,209,129	236,863,662	279,692,803	293,573,602	291,377,363		
19	Plant Investment				26,711,481	27,066,440	27,066,440	27,066,440	27,066,440	27,066,440	27,066,440	38,086,162	335,410,333	335,410,333
20	Depreciation Reserve				20,924	63,427	106,586	149,746	192,906	236,066	279,225	333,987	938,011	938,011
21	Accumulated Deferred Taxes	3,850,888	8,234,808	12,618,728	17,002,649	21,386,569	25,770,489	30,154,410	34,538,330	38,922,251	43,306,171	47,690,091	52,074,012	52,074,012
22	Rate Base	78,134,690	75,685,054	106,092,724	119,671,767	126,002,188	157,360,298	192,971,413	229,198,866	267,600,926	277,054,645	281,439,447	282,398,311	282,398,311
23	Rate Base from Previous Period	75,786,589	78,134,690	75,685,054	106,092,724	119,671,767	126,002,188	157,360,298	192,971,413	229,198,866	267,600,926	277,054,645	281,439,447	281,439,447
24	Average Rate Base	76,960,639	76,909,872	90,888,889	112,882,245	122,836,977	141,681,243	175,165,856	211,085,139	248,399,896	272,327,786	279,247,046	281,918,879	281,918,879
25														
26	LT Debt Return	139,812	139,720	165,115	205,069	223,154	257,388	318,218	383,471	451,260	494,729	507,299	512,153	3,797,386
27	ST Debt Return	4,489	4,486	5,302	6,585	7,165	8,265	10,218	12,313	14,490	15,886	16,289	16,445	121,934
28	Equity Return	336,703	336,481	397,639	493,860	537,412	619,855	766,351	923,497	1,086,750	1,191,434	1,221,706	1,233,395	9,145,082
29														
30	Tax Depreciation & Removal	11,330,354	11,330,354	11,330,354	11,330,354	11,330,354	11,330,354	11,330,354	11,330,354	11,330,354	11,330,354	11,330,354	11,330,354	135,964,251
31	Avoided Tax Interest	243,143	257,062	313,865	357,020	357,198	429,342	546,411	671,272	800,774	889,797	910,102	459,150	6,235,137
32	Book Depreciation				20,924	42,503	43,160	43,160	43,160	43,160	43,160	54,761	604,024	938,011
33	AFUDC													
34														
35	Annual Deferred Tax	4,383,920	4,383,920	4,383,920	4,383,920	4,383,920	4,383,920	4,383,920	4,383,920	4,383,920	4,383,920	4,383,920	4,383,920	52,607,044
36	Operating Expense	192,299	192,299	192,299	192,299	192,299	192,299	192,299	192,299	192,299	192,299	192,299	192,299	2,307,585
37	Property Tax Expense													
38														
39	Current Income Tax Requirement	(4,492,337)	(4,482,673)	(4,399,438)	(4,286,329)	(4,240,246)	(4,130,703)	(3,944,729)	(3,745,742)	(3,539,171)	(3,402,489)	(3,358,615)	(3,280,998)	(47,303,471)
40	Production Tax Credit												(3,001,718)	(3,001,718)
41														
42	**Total Revenue Requirements**	564,886	574,233	744,836	1,016,328	1,146,207	1,374,183	1,769,436	2,192,919	2,632,707	2,918,939	3,017,659	659,520	18,611,855
43														
44	Jurisdictional Allocation Factor *	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%
45	Interchange Allocation Factor	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%
46	**State Jurisdictional Revenue Requirement**	413,577	420,454	545,227	743,830	838,875	1,005,630	1,294,726	1,604,457	1,926,093	2,135,426	2,207,629	483,183	13,619,105

* Note: State Jurisdictional Requirements are calculated using Energy and Demand allocators applied to the separate Production and Transmission components of the project.

Line No.	NSPM Rider Revenue Requirements calculation - MN RES *Amounts in $ Dollars*	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	2017
	Blazing Star II													
2	**Cap Structure and Tax Rates**													
3	LT Debt Cost	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%
4	LT Debt Ratio	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%
5	LT Debt Weighted Cost Rounded	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%
6	ST Debt Cost	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%
7	ST Debt Ratio	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%
8	ST Debt Weighted Cost Rounded	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
9	Equity Cost	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
10	Equity Ratio	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%
11	Equity Weighted Cost Rounded	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%
12														
13	Fed Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
14	State Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
15	State Composite Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
16														
17	**Revenue Requirement Calculation**													
18	CWIP										1,032,033	1,086,377	1,122,357	1,122,357
19	Plant Investment													
20	Depreciation Reserve													
21	Accumulated Deferred Taxes	(256)	(511)	(767)	(1,023)	(1,278)	(1,534)	(1,790)	(2,045)	(2,301)	(2,557)	(2,812)	(3,068)	(3,068)
22	Rate Base	256	511	767	1,023	1,278	1,534	1,790	2,045	2,301	1,034,590	1,089,189	1,125,425	1,125,425
23	Rate Base from Previous Period		256	511	767	1,023	1,278	1,534	1,790	2,045	2,301	1,034,590	1,089,189	1,089,189
24	Average Rate Base	128	384	639	895	1,151	1,406	1,662	1,918	2,173	518,446	1,061,890	1,107,307	1,107,307
25														
26	LT Debt Return	0	1	1	2	2	3	3	4	4	955	1,956	2,039	4,969
27	ST Debt Return	0	0	0	0	0	0	0	0	0	22	44	46	112
28	Equity Return	1	2	3	4	5	6	7	8	10	2,268	4,646	4,844	11,804
29														
30	Tax Depreciation & Removal													
31	Avoided Tax Interest										1,443	2,967	3,101	7,511
32	Book Depreciation													
33	AFUDC													
34														
35	Annual Deferred Tax	(256)	(256)	(256)	(256)	(256)	(256)	(256)	(256)	(256)	(256)	(256)	(256)	(3,068)
36	Operating Expense													
37	Property Tax Expense													
38														
39	Current Income Tax Requirement	(180)	(179)	(178)	(178)	(177)	(176)	(175)	(174)	(174)	2,438	5,191	5,426	11,464
40	Production Tax Credit													
41														
42	**Total Revenue Requirements**	(435)	(432)	(430)	(428)	(425)	(423)	(421)	(418)	(416)	5,427	11,581	12,100	25,281
43														
44	Jurisdictional Allocation Factor *	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%
45	Interchange Allocation Factor	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%
46	**State Jurisdictional Revenue Requirement**	(320)	(318)	(317)	(315)	(313)	(311)	(310)	(308)	(306)	3,996	8,526	8,908	18,612

* Note: State Jurisdictional Requirements are calculated using Energy and Demand allocators applied to the separate Production and Transmission components of the project.

Line No.	NSPM Rider Revenue Requirements calculation - MN RES *Amounts in $ Dollars*	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	2018
	Blazing Star II													
2	**Cap Structure and Tax Rates**													
3	LT Debt Cost	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%
4	LT Debt Ratio	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%
5	LT Debt Weighted Cost Rounded	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%
6	ST Debt Cost	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%
7	ST Debt Ratio	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%
8	ST Debt Weighted Cost Rounded	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
9	Equity Cost	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
10	Equity Ratio	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%
11	Equity Weighted Cost Rounded	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%
12														
13	Fed Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
14	State Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
15	State Composite Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
16														
17	**Revenue Requirement Calculation**													
18	CWIP	1,133,504	1,148,368	1,494,374	4,480,984	4,510,751	4,530,413	8,168,145	27,431,380	27,642,889	27,943,421	28,095,504	28,153,048	28,153,048
19	Plant Investment													
20	Depreciation Reserve													
21	Accumulated Deferred Taxes	(18,030)	(32,992)	(47,954)	(62,917)	(77,879)	(92,841)	(107,803)	(122,765)	(137,727)	(152,689)	(167,651)	(182,614)	(182,614)
22	Rate Base	1,151,534	1,181,360	1,542,328	4,543,901	4,588,629	4,623,253	8,275,948	27,554,145	27,780,616	28,096,111	28,263,155	28,335,662	28,335,662
23	Rate Base from Previous Period	1,125,425	1,151,534	1,181,360	1,542,328	4,543,901	4,588,629	4,623,253	8,275,948	27,554,145	27,780,616	28,096,111	28,263,155	28,263,155
24	Average Rate Base	1,138,479	1,166,447	1,361,844	3,043,115	4,566,265	4,605,941	6,449,601	17,915,047	27,667,380	27,938,363	28,179,633	28,299,408	28,299,408
25														
26	LT Debt Return	2,097	2,148	2,508	5,604	8,410	8,483	11,878	32,994	50,954	51,453	51,897	52,118	280,544
27	ST Debt Return	47	49	57	127	190	192	269	746	1,153	1,164	1,174	1,179	6,347
28	Equity Return	4,981	5,103	5,958	13,314	19,977	20,151	28,217	78,378	121,045	122,230	123,286	123,810	666,450
29														
30	Tax Depreciation & Removal													
31	Avoided Tax Interest	3,274	3,321	3,851	8,667	13,041	13,150	18,461	51,534	79,761	80,730	81,615	82,153	439,558
32	Book Depreciation													
33	AFUDC													
34														
35	Annual Deferred Tax	(14,962)	(14,962)	(14,962)	(14,962)	(14,962)	(14,962)	(14,962)	(14,962)	(14,962)	(14,962)	(14,962)	(14,962)	(179,546)
36	Operating Expense													
37	Property Tax Expense													
38														
39	Current Income Tax Requirement	(4,733)	(4,613)	(3,636)	4,952	12,741	12,940	22,379	81,110	131,134	132,653	134,023	134,772	653,723
40	Production Tax Credit													
41														
42	**Total Revenue Requirements**	(12,570)	(12,275)	(10,075)	9,035	26,356	26,804	47,781	178,266	289,323	292,539	295,418	296,917	1,427,519
43														
44	Jurisdictional Allocation Factor *	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%
45	Interchange Allocation Factor	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%
46	**State Jurisdictional Revenue Requirement**	(9,222)	(9,006)	(7,393)	6,634	19,350	19,678	35,074	130,747	212,158	214,516	216,627	217,725	1,046,889

* Note: State Jurisdictional Requirements are calculated using Energy and Demand allocators applied to the separate Production and Transmission components of the project.

Line No.	NSPM Rider Revenue Requirements calculation - MN RES *Amounts in $ Dollars*	Jan - 2019	Feb - 2019	Mar - 2019	Apr - 2019	May - 2019	Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	2019
	Blazing Star II													
2	**Cap Structure and Tax Rates**													
3	LT Debt Cost	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%
4	LT Debt Ratio	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%
5	LT Debt Weighted Cost Rounded	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%
6	ST Debt Cost	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%
7	ST Debt Ratio	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%
8	ST Debt Weighted Cost Rounded	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%
9	Equity Cost	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
10	Equity Ratio	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%
11	Equity Weighted Cost Rounded	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%
12														
13	Fed Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
14	State Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
15	State Composite Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
16														
17	**Revenue Requirement Calculation**													
18	CWIP	28,284,087	35,914,741	36,286,530	43,260,976	44,508,616	60,105,484	74,068,392	95,558,930	105,392,986	140,899,685	105,959,357	106,879,452	106,879,452
19	Plant Investment					58,428	58,428	58,428	58,428	58,428	58,428	38,315,228	38,315,228	38,315,228
20	Depreciation Reserve					108	324	540	756	971	1,187	31,371	91,523	91,523
21	Accumulated Deferred Taxes	130,348	443,309	756,270	1,069,232	1,382,193	1,695,154	2,008,115	2,321,077	2,634,038	2,946,999	3,259,960	3,572,922	3,572,922
22	Rate Base	28,153,740	35,471,432	35,530,260	42,191,744	43,184,744	58,468,435	72,118,165	93,295,527	102,816,405	138,009,927	140,983,254	141,530,236	141,530,236
23	Rate Base from Previous Period	28,335,662	28,153,740	35,471,432	35,530,260	42,191,744	43,184,744	58,468,435	72,118,165	93,295,527	102,816,405	138,009,927	140,983,254	140,983,254
24	Average Rate Base	28,244,701	31,812,586	35,500,846	38,861,002	42,688,244	50,826,589	65,293,300	82,706,846	98,055,966	120,413,166	139,496,590	141,256,745	141,256,745
25														
26	LT Debt Return	51,311	57,793	64,493	70,597	77,550	92,335	118,616	150,251	178,135	218,751	253,419	256,616	1,589,868
27	ST Debt Return	1,648	1,856	2,071	2,267	2,490	2,965	3,809	4,825	5,720	7,024	8,137	8,240	51,051
28	Equity Return	123,571	139,180	155,316	170,017	186,761	222,366	285,658	361,842	428,995	526,808	610,298	617,998	3,828,810
29														
30	Tax Depreciation & Removal	990,694	990,694	990,694	990,694	990,694	990,694	990,694	990,694	990,694	990,694	990,694	990,694	11,888,329
31	Avoided Tax Interest	87,503	99,576	112,055	123,568	136,564	162,785	208,410	263,173	311,799	381,972	384,481	330,725	2,602,610
32	Book Depreciation					108	216	216	216	216	216	30,184	60,152	91,523
33	AFUDC													
34														
35	Annual Deferred Tax	312,961	312,961	312,961	312,961	312,961	312,961	312,961	312,961	312,961	312,961	312,961	312,961	3,755,535
36	Operating Expense													
37	Property Tax Expense													
38														
39	Current Income Tax Requirement	(329,280)	(309,747)	(289,556)	(271,059)	(249,998)	(206,297)	(129,443)	(37,046)	44,649	163,181	245,009	233,658	(1,135,930)
40	Production Tax Credit													
41														
42	**Total Revenue Requirements**	160,210	202,043	245,286	284,783	329,872	424,547	591,817	793,049	970,676	1,228,941	1,460,007	1,489,625	8,180,857
43														
44	Jurisdictional Allocation Factor *	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%
45	Interchange Allocation Factor	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%
46	**State Jurisdictional Revenue Requirement**	117,177	147,820	179,494	208,423	241,440	310,706	433,086	580,366	710,368	899,251	1,068,264	1,089,945	5,986,340

* Note: State Jurisdictional Requirements are calculated using Energy and Demand allocators applied to the separate Production and Transmission components of the project.

Line No.	NSPM Rider Revenue Requirements calculation - MN RES *Amounts in $ Dollars*	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	2017
	Courtenay Wind													
2	**Cap Structure and Tax Rates**													
3	LT Debt Cost	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%
4	LT Debt Ratio	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%
5	LT Debt Weighted Cost Rounded	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%
6	ST Debt Cost	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%
7	ST Debt Ratio	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%
8	ST Debt Weighted Cost Rounded	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
9	Equity Cost	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
10	Equity Ratio	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%
11	Equity Weighted Cost Rounded	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%
12														
13	Fed Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
14	State Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
15	State Composite Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
16														
17	**Revenue Requirement Calculation**													
18	CWIP													
19	Plant Investment	284,886,856	284,890,972	284,605,691	285,263,328	285,712,286	285,013,034	285,043,725	285,045,866	284,863,530	284,868,460	284,868,460	284,868,460	284,868,460
20	Depreciation Reserve	2,462,024	3,456,558	4,450,579	5,445,282	6,442,019	7,438,871	8,435,063	9,431,317	10,427,554	11,423,782	12,420,020	13,416,257	13,416,257
21	Accumulated Deferred Taxes	61,851,167	63,061,021	64,270,874	65,480,728	66,690,582	67,900,436	69,110,289	70,320,143	71,529,997	72,739,851	73,949,704	75,159,558	75,159,558
22	Rate Base	220,573,665	218,373,394	215,884,238	214,337,318	212,579,685	209,673,728	207,498,373	205,294,407	202,905,978	200,704,827	198,498,735	196,292,644	196,292,644
23	Rate Base from Previous Period	222,764,411	220,573,665	218,373,394	215,884,238	214,337,318	212,579,685	209,673,728	207,498,373	205,294,407	202,905,978	200,704,827	198,498,735	198,498,735
24	Average Rate Base	221,669,038	219,473,530	217,128,816	215,110,778	213,458,502	211,126,707	208,586,050	206,396,390	204,100,193	201,805,402	199,601,781	197,395,690	197,395,690
25														
26	LT Debt Return	408,240	404,197	399,879	396,162	393,119	388,825	384,146	380,113	375,885	371,658	367,600	363,537	4,633,362
27	ST Debt Return	9,236	9,145	9,047	8,963	8,894	8,797	8,691	8,600	8,504	8,409	8,317	8,225	104,827
28	Equity Return	969,802	960,197	949,939	941,110	933,881	923,679	912,564	902,984	892,938	882,899	873,258	863,606	11,006,856
29														
30	Tax Depreciation & Removal	3,957,317	3,957,317	3,957,317	3,957,317	3,957,317	3,957,317	3,957,317	3,957,317	3,957,317	3,957,317	3,957,317	3,957,317	47,487,809
31	Avoided Tax Interest													
32	Book Depreciation	994,502	994,534	994,021	994,703	996,738	996,851	996,193	996,254	996,238	996,228	996,237	996,237	11,948,736
33	AFUDC													
34														
35	Annual Deferred Tax	1,209,854	1,209,854	1,209,854	1,209,854	1,209,854	1,209,854	1,209,854	1,209,854	1,209,854	1,209,854	1,209,854	1,209,854	14,518,245
36	Operating Expense	679,047	496,250	83,973	1,308,243	(386,845)	559,749	636,849	257,888	370,247	575,009	568,294	610,762	5,759,466
37	Property Tax Expense	85,876	85,876	85,877	85,877	85,877	85,522	85,522	85,522	85,328	85,328	85,328	85,328	1,027,263
38	Interconnection Costs	136,654	136,654	136,654	136,654	136,654	136,654	136,654	136,654	136,654	136,654	136,654	136,654	1,639,848
39														
40	Current Income Tax Requirement	(552,606)	(559,362)	(566,962)	(572,710)	(576,375)	(583,493)	(591,801)	(598,518)	(605,618)	(612,709)	(619,505)	(626,315)	(7,065,973)
41	Production Tax Credit	(3,328,124)	(2,807,174)	(2,723,270)	(2,522,453)	(2,843,885)	(2,454,598)	(1,791,748)	(1,422,289)	(2,517,682)	(3,060,404)	(2,850,554)	(2,829,207)	(31,151,388)
42														
43	**Total Revenue Requirements**	612,482	930,171	579,012	1,986,402	(42,089)	1,271,840	1,986,923	1,957,062	952,348	592,926	775,483	818,681	12,421,242
44														
45	Jurisdictional Allocation Factor *	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%
46	Interchange Allocation Factor	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%
47	**State Jurisdictional Revenue Requirement**	457,446	690,313	431,756	1,467,046	(25,088)	941,100	1,466,149	1,443,530	706,088	442,535	576,502	608,247	9,205,625

* Note: State Jurisdictional Requirements are calculated using Energy and Demand allocators applied to the separate Production and Transmission components of the project.

Line No.	NSPM Rider Revenue Requirements calculation - MN RES *Amounts in $ Dollars*	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	2018
	Courtenay Wind													
2	**Cap Structure and Tax Rates**													
3	LT Debt Cost	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%
4	LT Debt Ratio	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%
5	LT Debt Weighted Cost Rounded	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%
6	ST Debt Cost	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%
7	ST Debt Ratio	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%
8	ST Debt Weighted Cost Rounded	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
9	Equity Cost	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
10	Equity Ratio	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%
11	Equity Weighted Cost Rounded	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%
12														
13	Fed Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
14	State Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
15	State Composite Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
16														
17	**Revenue Requirement Calculation**													
18	CWIP													
19	Plant Investment	284,868,460	284,868,460	284,868,460	284,868,460	284,868,460	284,868,460	284,868,460	284,868,460	284,868,460	284,868,460	284,868,460	284,868,460	284,868,460
20	Depreciation Reserve	14,412,494	15,408,732	16,404,969	17,401,206	18,397,444	19,393,681	20,389,918	21,386,155	22,382,393	23,378,630	24,374,867	25,371,105	25,371,105
21	Accumulated Deferred Taxes	75,777,064	76,394,570	77,012,076	77,629,582	78,247,088	78,864,594	79,482,100	80,099,606	80,717,112	81,334,617	81,952,123	82,569,629	82,569,629
22	Rate Base	194,678,901	193,065,158	191,451,415	189,837,672	188,223,928	186,610,185	184,996,442	183,382,699	181,768,955	180,155,212	178,541,469	176,927,726	176,927,726
23	Rate Base from Previous Period	196,292,644	194,678,901	193,065,158	191,451,415	189,837,672	188,223,928	186,610,185	184,996,442	183,382,699	181,768,955	180,155,212	178,541,469	178,541,469
24	Average Rate Base	195,485,773	193,872,030	192,258,286	190,644,543	189,030,800	187,417,057	185,803,313	184,189,570	182,575,827	180,962,084	179,348,341	177,734,597	177,734,597
25														
26	LT Debt Return	360,020	357,048	354,076	351,104	348,132	345,160	342,188	339,216	336,244	333,272	330,300	327,328	4,124,085
27	ST Debt Return	8,145	8,078	8,011	7,944	7,876	7,809	7,742	7,675	7,607	7,540	7,473	7,406	93,305
28	Equity Return	855,250	848,190	841,130	834,070	827,010	819,950	812,889	805,829	798,769	791,709	784,649	777,589	9,797,035
29														
30	Tax Depreciation & Removal	2,507,657	2,507,657	2,507,657	2,507,657	2,507,657	2,507,657	2,507,657	2,507,657	2,507,657	2,507,657	2,507,657	2,507,657	30,091,887
31	Avoided Tax Interest													
32	Book Depreciation	996,237	996,237	996,237	996,237	996,237	996,237	996,237	996,237	996,237	996,237	996,237	996,237	11,954,848
33	AFUDC													
34														
35	Annual Deferred Tax	617,506	617,506	617,506	617,506	617,506	617,506	617,506	617,506	617,506	617,506	617,506	617,506	7,410,071
36	Operating Expense	617,138	617,138	617,138	617,138	617,138	617,138	617,138	617,138	617,138	617,138	617,138	617,138	7,405,661
37	Property Tax Expense	85,328	85,328	85,328	85,328	85,328	85,328	85,328	85,328	85,328	85,328	85,328	85,328	1,023,938
38	Interconnection Costs	142,373	142,373	142,373	142,373	142,373	142,373	142,373	142,373	142,373	142,373	142,373	142,373	1,708,471
39														
40	Current Income Tax Requirement	(27,282)	(32,263)	(37,245)	(42,227)	(47,208)	(52,190)	(57,172)	(62,154)	(67,135)	(72,117)	(77,099)	(82,080)	(656,172)
41	Production Tax Credit	(3,233,156)	(2,576,930)	(3,287,753)	(3,425,004)	(2,845,924)	(2,515,414)	(1,937,505)	(2,024,103)	(2,778,541)	(3,255,750)	(3,032,505)	(3,009,795)	(33,922,381)
42														
43	**Total Revenue Requirements**	421,560	1,062,705	336,801	184,469	748,468	1,063,896	1,626,725	1,525,046	755,526	263,237	471,400	479,029	8,938,861
44														
45	Jurisdictional Allocation Factor *	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%
46	Interchange Allocation Factor	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%
47	**State Jurisdictional Revenue Requirement**	314,655	783,712	252,599	141,127	553,742	784,496	1,196,254	1,121,841	558,818	198,623	350,899	356,459	6,613,225

* Note: State Jurisdictional Requirements are calculated using Energy and Demand allocators applied to the separate Production and Transmission components of the project.

Line No.	NSPM Rider Revenue Requirements calculation - MN RES *Amounts in $ Dollars*	Jan - 2019	Feb - 2019	Mar - 2019	Apr - 2019	May - 2019	Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	2019
	Courtenay Wind													
2	**Cap Structure and Tax Rates**													
3	LT Debt Cost	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%
4	LT Debt Ratio	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%
5	LT Debt Weighted Cost Rounded	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%
6	ST Debt Cost	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%
7	ST Debt Ratio	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%
8	ST Debt Weighted Cost Rounded	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%
9	Equity Cost	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
10	Equity Ratio	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%
11	Equity Weighted Cost Rounded	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%
12														
13	Fed Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
14	State Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
15	State Composite Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
16														
17	**Revenue Requirement Calculation**													
18	CWIP													
19	Plant Investment	284,868,460	284,868,460	284,868,460	284,868,460	284,868,460	284,868,460	284,868,460	284,868,460	284,868,460	284,868,460	284,868,460	284,868,460	284,868,460
20	Depreciation Reserve	26,367,342	27,363,579	28,359,817	29,356,054	30,352,291	31,348,529	32,344,766	33,341,003	34,337,240	35,333,478	36,329,715	37,325,952	37,325,952
21	Accumulated Deferred Taxes	82,829,528	83,089,426	83,349,324	83,609,223	83,869,121	84,129,019	84,388,918	84,648,816	84,908,714	85,168,613	85,428,511	85,688,409	85,688,409
22	Rate Base	175,671,590	174,415,454	173,159,319	171,903,183	170,647,047	169,390,912	168,134,776	166,878,641	165,622,505	164,366,369	163,110,234	161,854,098	161,854,098
23	Rate Base from Previous Period	176,927,726	175,671,590	174,415,454	173,159,319	171,903,183	170,647,047	169,390,912	168,134,776	166,878,641	165,622,505	164,366,369	163,110,234	163,110,234
24	Average Rate Base	176,299,658	175,043,522	173,787,387	172,531,251	171,275,115	170,018,980	168,762,844	167,506,708	166,250,573	164,994,437	163,738,301	162,482,166	162,482,166
25														
26	LT Debt Return	320,278	317,996	315,714	313,432	311,150	308,868	306,586	304,304	302,022	299,740	297,458	295,176	3,692,722
27	ST Debt Return	10,284	10,211	10,138	10,064	9,991	9,918	9,844	9,771	9,698	9,625	9,551	9,478	118,574
28	Equity Return	771,311	765,815	760,320	754,824	749,329	743,833	738,337	732,842	727,346	721,851	716,355	710,859	8,893,023
29														
30	Tax Depreciation & Removal	1,632,172	1,632,172	1,632,172	1,632,172	1,632,172	1,632,172	1,632,172	1,632,172	1,632,172	1,632,172	1,632,172	1,632,172	19,586,068
31	Avoided Tax Interest													
32	Book Depreciation	996,237	996,237	996,237	996,237	996,237	996,237	996,237	996,237	996,237	996,237	996,237	996,237	11,954,848
33	AFUDC													
34														
35	Annual Deferred Tax	259,898	259,898	259,898	259,898	259,898	259,898	259,898	259,898	259,898	259,898	259,898	259,898	3,118,780
36	Operating Expense	603,060	603,060	603,060	603,060	603,060	603,060	603,060	603,060	603,060	603,060	603,060	603,060	7,236,721
37	Property Tax Expense	85,328	85,328	85,328	85,328	85,328	85,328	85,328	85,328	85,328	85,328	85,328	85,328	1,023,938
38	Interconnection Costs	142,373	142,373	142,373	142,373	142,373	142,373	142,373	142,373	142,373	142,373	142,373	142,373	1,708,471
39														
40	Current Income Tax Requirement	278,910	275,032	271,155	267,277	263,399	259,521	255,644	251,766	247,888	244,010	240,133	236,255	3,090,989
41	Production Tax Credit	(3,233,156)	(2,576,930)	(3,287,753)	(3,425,004)	(2,845,924)	(2,515,414)	(1,937,505)	(2,024,103)	(2,778,541)	(3,255,750)	(3,030,425)	(3,009,795)	(33,920,301)
42														
43	**Total Revenue Requirements**	234,523	879,021	156,469	7,490	574,841	893,622	1,459,803	1,361,476	595,309	106,372	319,969	328,870	6,917,765
44														
45	Jurisdictional Allocation Factor *	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%
46	Interchange Allocation Factor	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%
47	**State Jurisdictional Revenue Requirement**	172,779	644,092	115,696	6,748	421,645	654,766	1,068,807	996,901	436,609	79,053	235,253	241,761	5,074,110

* Note: State Jurisdictional Requirements are calculated using Energy and Demand allocators applied to the separate Production and Transmission components of the project.

Line No.	NSPM Rider Revenue Requirements calculation - MN RES *Amounts in $ Dollars*	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	2017
	Crowned Ridge													
2	**Cap Structure and Tax Rates**													
3	LT Debt Cost	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%
4	LT Debt Ratio	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%
5	LT Debt Weighted Cost Rounded	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%
6	ST Debt Cost	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%
7	ST Debt Ratio	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%
8	ST Debt Weighted Cost Rounded	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
9	Equity Cost	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
10	Equity Ratio	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%
11	Equity Weighted Cost Rounded	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%
12														
13	Fed Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
14	State Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
15	State Composite Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
16														
17	**Revenue Requirement Calculation**													
18	CWIP										2,360,073	2,372,356	2,382,705	2,382,705
19	Plant Investment													
20	Depreciation Reserve													
21	Accumulated Deferred Taxes	(565)	(1,130)	(1,696)	(2,261)	(2,826)	(3,391)	(3,957)	(4,522)	(5,087)	(5,652)	(6,218)	(6,783)	(6,783)
22	Rate Base	565	1,130	1,696	2,261	2,826	3,391	3,957	4,522	5,087	2,365,725	2,378,574	2,389,488	2,389,488
23	Rate Base from Previous Period		565	1,130	1,696	2,261	2,826	3,391	3,957	4,522	5,087	2,365,725	2,378,574	2,378,574
24	Average Rate Base	283	848	1,413	1,978	2,544	3,109	3,674	4,239	4,804	1,185,406	2,372,150	2,384,031	2,384,031
25														
26	LT Debt Return	1	2	3	4	5	6	7	8	9	2,183	4,369	4,391	10,985
27	ST Debt Return	0	0	0	0	0	0	0	0	0	49	99	99	249
28	Equity Return	1	4	6	9	11	14	16	19	21	5,186	10,378	10,430	26,095
29														
30	Tax Depreciation & Removal													
31	Avoided Tax Interest										3,300	6,627	6,678	16,605
32	Book Depreciation													
33	AFUDC													
34														
35	Annual Deferred Tax	(565)	(565)	(565)	(565)	(565)	(565)	(565)	(565)	(565)	(565)	(565)	(565)	(6,783)
36	Operating Expense													
37	Property Tax Expense													
38														
39	Current Income Tax Requirement	(398)	(396)	(394)	(393)	(391)	(389)	(387)	(386)	(384)	5,589	11,600	11,673	25,344
40	Production Tax Credit													
41														
42	**Total Revenue Requirements**	(961)	(956)	(951)	(946)	(940)	(935)	(930)	(924)	(919)	12,443	25,881	26,027	55,889
43														
44	Jurisdictional Allocation Factor *	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%
45	Interchange Allocation Factor	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%
46	**State Jurisdictional Revenue Requirement**	(708)	(704)	(700)	(696)	(692)	(688)	(684)	(681)	(677)	9,160	19,053	19,161	41,145

* Note: State Jurisdictional Requirements are calculated using Energy and Demand allocators applied to the separate Production and Transmission components of the project.

Line No.	NSPM Rider Revenue Requirements calculation - MN RES *Amounts in $ Dollars*	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	2018
	Crowned Ridge													
2	**Cap Structure and Tax Rates**													
3	LT Debt Cost	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%
4	LT Debt Ratio	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%
5	LT Debt Weighted Cost Rounded	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%
6	ST Debt Cost	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%
7	ST Debt Ratio	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%
8	ST Debt Weighted Cost Rounded	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
9	Equity Cost	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
10	Equity Ratio	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%
11	Equity Weighted Cost Rounded	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%
12														
13	Fed Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
14	State Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
15	State Composite Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
16														
17	**Revenue Requirement Calculation**													
18	CWIP	29,065,036	29,077,271	29,093,148	29,110,714	29,132,874	53,178,542	53,205,607	53,235,409	53,262,632	53,295,351	53,327,887	53,361,177	53,361,177
19	Plant Investment													
20	Depreciation Reserve													
21	Accumulated Deferred Taxes	(55,810)	(104,836)	(153,863)	(202,890)	(251,917)	(300,944)	(349,971)	(398,997)	(448,024)	(497,051)	(546,078)	(595,105)	(595,105)
22	Rate Base	29,120,845	29,182,108	29,247,011	29,313,604	29,384,791	53,479,486	53,555,578	53,634,406	53,710,657	53,792,402	53,873,965	53,956,282	53,956,282
23	Rate Base from Previous Period	2,389,488	29,120,845	29,182,108	29,247,011	29,313,604	29,384,791	53,479,486	53,555,578	53,634,406	53,710,657	53,792,402	53,873,965	53,873,965
24	Average Rate Base	15,755,167	29,151,477	29,214,559	29,280,308	29,349,197	41,432,138	53,517,532	53,594,992	53,672,531	53,751,529	53,833,183	53,915,123	53,915,123
25														
26	LT Debt Return	29,016	53,687	53,803	53,925	54,051	76,304	98,561	98,704	98,847	98,992	99,143	99,294	914,328
27	ST Debt Return	656	1,215	1,217	1,220	1,223	1,726	2,230	2,233	2,236	2,240	2,243	2,246	20,686
28	Equity Return	68,929	127,538	127,814	128,101	128,403	181,266	234,139	234,478	234,817	235,163	235,520	235,879	2,172,046
29														
30	Tax Depreciation & Removal													
31	Avoided Tax Interest	45,390	84,010	84,292	84,584	84,885	119,831	154,885	155,414	155,944	156,480	157,026	157,573	1,440,313
32	Book Depreciation													
33	AFUDC													
34														
35	Annual Deferred Tax	(49,027)	(49,027)	(49,027)	(49,027)	(49,027)	(49,027)	(49,027)	(49,027)	(49,027)	(49,027)	(49,027)	(49,027)	(588,322)
36	Operating Expense													
37	Property Tax Expense													
38														
39	Current Income Tax Requirement	46,071	114,676	115,071	115,479	115,904	177,863	239,906	240,518	241,132	241,754	242,391	243,030	2,133,796
40	Production Tax Credit													
41														
42	**Total Revenue Requirements**	95,645	248,089	248,878	249,698	250,554	388,133	525,810	526,907	528,006	529,122	530,270	531,422	4,652,534
43														
44	Jurisdictional Allocation Factor *	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%
45	Interchange Allocation Factor	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%
46	**State Jurisdictional Revenue Requirement**	70,114	181,865	182,443	183,044	183,672	284,525	385,451	386,255	387,061	387,879	388,721	389,565	3,410,594

* Note: State Jurisdictional Requirements are calculated using Energy and Demand allocators applied to the separate Production and Transmission components of the project.

Line No.	NSPM Rider Revenue Requirements calculation - MN RES *Amounts in $ Dollars*	Jan - 2019	Feb - 2019	Mar - 2019	Apr - 2019	May - 2019	Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	2019
	Crowned Ridge													
2	**Cap Structure and Tax Rates**													
3	LT Debt Cost	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%
4	LT Debt Ratio	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%
5	LT Debt Weighted Cost Rounded	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%
6	ST Debt Cost	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%
7	ST Debt Ratio	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%
8	ST Debt Weighted Cost Rounded	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%
9	Equity Cost	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
10	Equity Ratio	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%
11	Equity Weighted Cost Rounded	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%
12														
13	Fed Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
14	State Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
15	State Composite Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
16														
17	**Revenue Requirement Calculation**													
18	CWIP	53,478,731	53,621,067	53,852,995	54,114,167	73,820,962	74,076,172	90,215,345	185,041,922	278,970,613				
19	Plant Investment										408,192,660	421,189,297	480,131,697	480,131,697
20	Depreciation Reserve										738,148	2,237,948	3,867,837	3,867,837
21	Accumulated Deferred Taxes	5,909,429	12,413,963	18,918,496	25,423,030	31,927,564	38,432,097	44,936,631	51,441,165	57,945,698	64,450,232	70,954,766	77,459,299	77,459,299
22	Rate Base	47,569,302	41,207,104	34,934,499	28,691,137	41,893,398	35,644,074	45,278,714	133,600,757	221,024,914	343,004,280	347,996,583	398,804,561	398,804,561
23	Rate Base from Previous Period	53,956,282	47,569,302	41,207,104	34,934,499	28,691,137	41,893,398	35,644,074	45,278,714	133,600,757	221,024,914	343,004,280	347,996,583	347,996,583
24	Average Rate Base	50,762,792	44,388,203	38,070,802	31,812,818	35,292,268	38,768,736	40,461,394	89,439,736	177,312,836	282,014,597	345,500,431	373,400,572	373,400,572
25														
26	LT Debt Return	92,219	80,639	69,162	57,793	64,114	70,430	73,505	162,482	322,118	512,327	627,659	678,344	2,810,792
27	ST Debt Return	2,961	2,589	2,221	1,856	2,059	2,262	2,360	5,217	10,343	16,451	20,154	21,782	90,255
28	Equity Return	222,087	194,198	166,560	139,181	154,404	169,613	177,019	391,299	775,744	1,233,814	1,511,564	1,633,628	6,769,110
29														
30	Tax Depreciation & Removal	16,500,507	16,500,507	16,500,507	16,500,507	16,500,507	16,500,507	16,500,507	16,500,507	16,500,507	16,500,507	16,500,507	16,500,507	198,006,080
31	Avoided Tax Interest	167,559	168,467	169,553	170,824	201,830	232,922	258,662	428,861	718,339	530,606			3,047,622
32	Book Depreciation										738,148	1,499,799	1,629,889	3,867,837
33	AFUDC													
34														
35	Annual Deferred Tax	6,504,534	6,504,534	6,504,534	6,504,534	6,504,534	6,504,534	6,504,534	6,504,534	6,504,534	6,504,534	6,504,534	6,504,534	78,054,404
36	Operating Expense	81,280	81,280	81,280	81,280	81,280	81,280	81,280	81,280	81,280	81,280	81,280	81,280	975,355
37	Property Tax Expense													
38														
39	Current Income Tax Requirement	(6,778,334)	(6,797,372)	(6,816,108)	(6,834,530)	(6,801,911)	(6,769,240)	(6,745,852)	(6,474,559)	(5,999,031)	(5,287,432)	(4,928,420)	(4,750,499)	(74,983,289)
40	Production Tax Credit												(5,024,589)	(5,024,589)
41														
42	**Total Revenue Requirements**	124,746	65,867	7,648	(49,887)	4,479	58,878	92,845	670,253	1,694,987	3,799,121	5,316,570	774,369	12,559,875
43														
44	Jurisdictional Allocation Factor *	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%
45	Interchange Allocation Factor	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%
46	**State Jurisdictional Revenue Requirement**	91,333	48,273	5,694	(36,383)	3,377	43,161	68,002	490,285	1,239,716	2,778,556	3,888,330	566,687	9,187,031

* Note: State Jurisdictional Requirements are calculated using Energy and Demand allocators applied to the separate Production and Transmission components of the project.

Line No.	NSPM Rider Revenue Requirements calculation - MN RES *Amounts in $ Dollars*	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	2017
	Foxtail													
2	**Cap Structure and Tax Rates**													
3	LT Debt Cost	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%
4	LT Debt Ratio	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%
5	LT Debt Weighted Cost Rounded	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%
6	ST Debt Cost	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%
7	ST Debt Ratio	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%
8	ST Debt Weighted Cost Rounded	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
9	Equity Cost	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
10	Equity Ratio	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%
11	Equity Weighted Cost Rounded	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%
12														
13	Fed Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
14	State Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
15	State Composite Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
16														
17	**Revenue Requirement Calculation**													
18	CWIP										3,443,107	19,220,096	34,470,229	34,470,229
19	Plant Investment													
20	Depreciation Reserve													
21	Accumulated Deferred Taxes	(3,802)	(7,605)	(11,407)	(15,210)	(19,012)	(22,815)	(26,617)	(30,420)	(34,222)	(38,025)	(41,827)	(45,629)	(45,629)
22	Rate Base	3,802	7,605	11,407	15,210	19,012	22,815	26,617	30,420	34,222	3,481,132	19,261,923	34,515,858	34,515,858
23	Rate Base from Previous Period		3,802	7,605	11,407	15,210	19,012	22,815	26,617	30,420	34,222	3,481,132	19,261,923	19,261,923
24	Average Rate Base	1,901	5,704	9,506	13,309	17,111	20,914	24,716	28,518	32,321	1,757,677	11,371,527	26,888,891	26,888,891
25														
26	LT Debt Return	4	11	18	25	32	39	46	53	60	3,237	20,943	49,520	73,984
27	ST Debt Return	0	0	0	1	1	1	1	1	1	73	474	1,120	1,674
28	Equity Return	8	25	42	58	75	91	108	125	141	7,690	49,750	117,639	175,753
29														
30	Tax Depreciation & Removal													
31	Avoided Tax Interest										4,815	31,707	75,186	111,709
32	Book Depreciation													
33	AFUDC													
34														
35	Annual Deferred Tax	(3,802)	(3,802)	(3,802)	(3,802)	(3,802)	(3,802)	(3,802)	(3,802)	(3,802)	(3,802)	(3,802)	(3,802)	(45,629)
36	Operating Expense													
37	Property Tax Expense													
38														
39	Current Income Tax Requirement	(2,677)	(2,665)	(2,654)	(2,642)	(2,630)	(2,618)	(2,607)	(2,595)	(2,583)	6,141	54,794	133,377	170,640
40	Production Tax Credit													
41														
42	**Total Revenue Requirements**	(6,468)	(6,432)	(6,397)	(6,361)	(6,326)	(6,290)	(6,255)	(6,219)	(6,183)	13,338	122,159	297,854	376,420
43														
44	Jurisdictional Allocation Factor *	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%	87.3462%
45	Interchange Allocation Factor	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%
46	**State Jurisdictional Revenue Requirement**	(4,760)	(4,734)	(4,708)	(4,682)	(4,656)	(4,629)	(4,603)	(4,577)	(4,551)	9,821	89,904	219,220	277,045

* Note: State Jurisdictional Requirements are calculated using Energy and Demand allocators applied to the separate Production and Transmission components of the project.

Line No.	NSPM Rider Revenue Requirements calculation - MN RES *Amounts in $ Dollars*	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	2018
	Foxtail													
2	**Cap Structure and Tax Rates**													
3	LT Debt Cost	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%
4	LT Debt Ratio	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%
5	LT Debt Weighted Cost Rounded	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%
6	ST Debt Cost	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%
7	ST Debt Ratio	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%
8	ST Debt Weighted Cost Rounded	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
9	Equity Cost	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
10	Equity Ratio	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%
11	Equity Weighted Cost Rounded	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%
12														
13	Fed Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
14	State Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
15	State Composite Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
16														
17	**Revenue Requirement Calculation**													
18	CWIP	39,081,724	39,186,008	39,326,557	39,462,103	39,892,841	44,549,956	48,845,763	56,583,814	67,393,622	59,610,778	63,954,939	89,954,656	89,954,656
19	Plant Investment										15,912,661	15,912,661	15,912,661	15,912,661
20	Depreciation Reserve										12,483	37,450	62,417	62,417
21	Accumulated Deferred Taxes	109,865	265,360	420,855	576,349	731,844	887,339	1,042,833	1,198,328	1,353,823	1,509,317	1,664,812	1,820,307	1,820,307
22	Rate Base	38,971,859	38,920,648	38,905,702	38,885,754	39,160,997	43,662,617	47,802,929	55,385,486	66,039,799	74,001,638	78,165,337	103,984,593	103,984,593
23	Rate Base from Previous Period	34,515,858	38,971,859	38,920,648	38,905,702	38,885,754	39,160,997	43,662,617	47,802,929	55,385,486	66,039,799	74,001,638	78,165,337	78,165,337
24	Average Rate Base	36,743,859	38,946,254	38,913,175	38,895,728	39,023,376	41,411,807	45,732,773	51,594,208	60,712,642	70,020,719	76,083,488	91,074,965	91,074,965
25														
26	LT Debt Return	67,670	71,726	71,665	71,633	71,868	76,267	84,225	95,019	111,812	128,955	140,120	167,730	1,158,690
27	ST Debt Return	1,531	1,623	1,621	1,621	1,626	1,725	1,906	2,150	2,530	2,918	3,170	3,795	26,215
28	Equity Return	160,754	170,390	170,245	170,169	170,727	181,177	200,081	225,725	265,618	306,341	332,865	398,453	2,752,544
29														
30	Tax Depreciation & Removal	532,046	532,046	532,046	532,046	532,046	532,046	532,046	532,046	532,046	532,046	532,046	532,046	6,384,548
31	Avoided Tax Interest	106,371	113,477	114,157	114,884	116,031	123,692	136,941	154,669	181,842	186,024	180,827	225,083	1,753,998
32	Book Depreciation										12,483	24,967	24,967	62,417
33	AFUDC													
34														
35	Annual Deferred Tax	155,495	155,495	155,495	155,495	155,495	155,495	155,495	155,495	155,495	155,495	155,495	155,495	1,865,936
36	Operating Expense													
37	Property Tax Expense													
38														
39	Current Income Tax Requirement	(77,212)	(65,399)	(65,021)	(64,562)	(63,359)	(50,580)	(27,892)	2,712	50,034	90,528	114,385	191,892	35,526
40	Production Tax Credit													
41														
42	**Total Revenue Requirements**	308,238	333,834	334,005	334,355	336,357	364,083	413,813	481,100	585,489	696,719	771,003	942,331	5,901,328
43														
44	Jurisdictional Allocation Factor *	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%	87.3171%
45	Interchange Allocation Factor	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%
46	**State Jurisdictional Revenue Requirement**	226,108	244,870	244,994	245,248	246,714	267,046	303,530	352,887	429,419	510,961	565,418	691,010	4,328,205

* Note: State Jurisdictional Requirements are calculated using Energy and Demand allocators applied to the separate Production and Transmission components of the project.

Line No.	NSPM Rider Revenue Requirements calculation - MN RES *Amounts in $ Dollars*	Jan - 2019	Feb - 2019	Mar - 2019	Apr - 2019	May - 2019	Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	2019
	Foxtail													
2	**Cap Structure and Tax Rates**													
3	LT Debt Cost	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%
4	LT Debt Ratio	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%
5	LT Debt Weighted Cost Rounded	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%
6	ST Debt Cost	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%
7	ST Debt Ratio	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%
8	ST Debt Weighted Cost Rounded	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%
9	Equity Cost	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
10	Equity Ratio	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%
11	Equity Weighted Cost Rounded	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%
12														
13	Fed Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
14	State Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
15	State Composite Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
16														
17	**Revenue Requirement Calculation**													
18	CWIP	90,404,753	92,649,523	93,206,856	93,646,542	115,346,371	135,135,482	160,209,919	189,254,587	218,366,492	227,570,994	225,727,144		
19	Plant Investment	15,912,661	15,912,661	15,912,661	15,912,661	15,912,661	15,912,661	15,912,661	15,912,661	15,912,661	16,097,153	22,545,817	255,669,339	255,669,339
20	Depreciation Reserve	87,384	112,351	137,317	162,284	187,251	212,218	237,185	262,152	287,118	312,432	344,882	805,687	805,687
21	Accumulated Deferred Taxes	5,052,441	8,284,576	11,516,710	14,748,845	17,980,979	21,213,113	24,445,248	27,677,382	30,909,517	34,141,651	37,373,786	40,605,920	40,605,920
22	Rate Base	101,177,588	100,165,257	97,465,489	94,648,074	113,090,801	129,622,811	151,440,147	177,227,714	203,082,517	209,214,064	210,554,293	214,257,731	214,257,731
23	Rate Base from Previous Period	103,984,593	101,177,588	100,165,257	97,465,489	94,648,074	113,090,801	129,622,811	151,440,147	177,227,714	203,082,517	209,214,064	210,554,293	210,554,293
24	Average Rate Base	102,581,091	100,671,422	98,815,373	96,056,781	103,869,438	121,356,806	140,531,479	164,333,931	190,155,115	206,148,290	209,884,178	212,406,012	212,406,012
25														
26	LT Debt Return	186,356	182,886	179,515	174,503	188,696	220,465	255,299	298,540	345,448	374,503	381,290	385,871	3,173,371
27	ST Debt Return	5,984	5,872	5,764	5,603	6,059	7,079	8,198	9,586	11,092	12,025	12,243	12,390	101,897
28	Equity Return	448,792	440,437	432,317	420,248	454,429	530,936	614,825	718,961	831,929	901,899	918,243	929,276	7,642,293
29														
30	Tax Depreciation & Removal	8,413,594	8,413,594	8,413,594	8,413,594	8,413,594	8,413,594	8,413,594	8,413,594	8,413,594	8,413,594	8,413,594	8,413,594	100,963,124
31	Avoided Tax Interest	279,379	284,327	289,455	291,841	326,522	390,859	460,545	544,573	635,023	695,559	708,559	359,351	5,265,994
32	Book Depreciation	24,967	24,967	24,967	24,967	24,967	24,967	24,967	24,967	24,967	25,313	32,450	460,805	743,270
33	AFUDC													
34														
35	Annual Deferred Tax	3,232,134	3,232,134	3,232,134	3,232,134	3,232,134	3,232,134	3,232,134	3,232,134	3,232,134	3,232,134	3,232,134	3,232,134	38,785,613
36	Operating Expense	67,309	67,309	67,309	67,309	67,309	67,309	67,309	67,309	67,309	67,309	67,309	67,309	807,703
37	Property Tax Expense													
38														
39	Current Income Tax Requirement	(3,124,674)	(3,127,078)	(3,129,190)	(3,136,021)	(3,087,432)	(2,988,051)	(2,879,687)	(2,746,916)	(2,603,383)	(2,511,051)	(2,485,309)	(2,421,678)	(34,240,469)
40	Production Tax Credit												(2,259,916)	(2,259,916)
41														
42	**Total Revenue Requirements**	840,868	826,528	812,816	788,743	886,162	1,094,839	1,323,045	1,604,581	1,909,497	2,102,133	2,158,360	406,192	14,753,763
43														
44	Jurisdictional Allocation Factor *	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%	87.2773%
45	Interchange Allocation Factor	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%
46	**State Jurisdictional Revenue Requirement**	615,305	604,817	594,788	577,181	648,426	801,039	967,934	1,173,832	1,396,828	1,537,710	1,578,836	297,522	10,794,216

* Note: State Jurisdictional Requirements are calculated using Energy and Demand allocators applied to the separate Production and Transmission components of the project.

Line No.	NSPM Rider Revenue Requirements calculation - MN RES *Amounts in $ Dollars*	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	2017
	Freeborn													
2	**Cap Structure and Tax Rates**													
3	LT Debt Cost	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%
4	LT Debt Ratio	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%
5	LT Debt Weighted Cost Rounded	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%
6	ST Debt Cost	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%
7	ST Debt Ratio	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%
8	ST Debt Weighted Cost Rounded	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
9	Equity Cost	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
10	Equity Ratio	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%
11	Equity Weighted Cost Rounded	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%
12														
13	Fed Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
14	State Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
15	State Composite Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
16														
17	**Revenue Requirement Calculation**													
18	CWIP										1,498,875	1,595,172	2,226,529	2,226,529
19	Plant Investment													
20	Depreciation Reserve													
21	Accumulated Deferred Taxes	(401)	(803)	(1,204)	(1,605)	(2,007)	(2,408)	(2,810)	(3,211)	(3,612)	(4,014)	(4,415)	(4,816)	(4,816)
22	Rate Base	401	803	1,204	1,605	2,007	2,408	2,810	3,211	3,612	1,502,888	1,599,587	2,231,345	2,231,345
23	Rate Base from Previous Period		401	803	1,204	1,605	2,007	2,408	2,810	3,211	3,612	1,502,888	1,599,587	1,599,587
24	Average Rate Base	201	602	1,003	1,405	1,806	2,208	2,609	3,010	3,412	753,250	1,551,238	1,915,466	1,915,466
25														
26	LT Debt Return	0	1	2	3	3	4	5	6	6	1,387	2,857	3,528	7,802
27	ST Debt Return	0	0	0	0	0	0	0	0	0	31	65	80	177
28	Equity Return	1	3	4	6	8	10	11	13	15	3,295	6,787	8,380	18,533
29														
30	Tax Depreciation & Removal													
31	Avoided Tax Interest										2,096	4,333	5,363	11,791
32	Book Depreciation													
33	AFUDC													
34														
35	Annual Deferred Tax	(401)	(401)	(401)	(401)	(401)	(401)	(401)	(401)	(401)	(401)	(401)	(401)	(4,816)
36	Operating Expense													
37	Property Tax Expense													
38														
39	Current Income Tax Requirement	(283)	(281)	(280)	(279)	(278)	(276)	(275)	(274)	(273)	3,521	7,563	9,414	17,999
40	Production Tax Credit													
41														
42	**Total Revenue Requirements**	(683)	(679)	(675)	(671)	(668)	(664)	(660)	(656)	(653)	7,834	16,870	21,000	39,694
43														
44	Jurisdictional Allocation Factor *	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%
45	Interchange Allocation Factor	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%
46	**State Jurisdictional Revenue Requirement**	(503)	(500)	(497)	(494)	(492)	(489)	(486)	(483)	(481)	5,767	12,419	15,460	29,223

* Note: State Jurisdictional Requirements are calculated using Energy and Demand allocators applied to the separate Production and Transmission components of the project.

Line No.	NSPM Rider Revenue Requirements calculation - MN RES *Amounts in $ Dollars*	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	2018
	Freeborn													
2	**Cap Structure and Tax Rates**													
3	LT Debt Cost	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%
4	LT Debt Ratio	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%
5	LT Debt Weighted Cost Rounded	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%
6	ST Debt Cost	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%
7	ST Debt Ratio	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%
8	ST Debt Weighted Cost Rounded	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
9	Equity Cost	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
10	Equity Ratio	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%
11	Equity Weighted Cost Rounded	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%
12														
13	Fed Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
14	State Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
15	State Composite Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
16														
17	**Revenue Requirement Calculation**													
18	CWIP	2,260,132	2,288,666	2,319,882	2,349,119	2,396,985	15,499,229	15,594,271	15,693,805	15,772,623	15,859,027	15,938,797	16,010,887	16,010,887
19	Plant Investment													
20	Depreciation Reserve													
21	Accumulated Deferred Taxes	(16,153)	(27,489)	(38,825)	(50,161)	(61,497)	(72,834)	(84,170)	(95,506)	(106,842)	(118,178)	(129,515)	(140,851)	(140,851)
22	Rate Base	2,276,284	2,316,155	2,358,707	2,399,281	2,458,482	15,572,062	15,678,441	15,789,311	15,879,465	15,977,205	16,068,312	16,151,738	16,151,738
23	Rate Base from Previous Period	2,231,345	2,276,284	2,316,155	2,358,707	2,399,281	2,458,482	15,572,062	15,678,441	15,789,311	15,879,465	15,977,205	16,068,312	16,068,312
24	Average Rate Base	2,253,815	2,296,220	2,337,431	2,378,994	2,428,881	9,015,272	15,625,252	15,733,876	15,834,388	15,928,335	16,022,759	16,110,025	16,110,025
25														
26	LT Debt Return	4,151	4,229	4,305	4,381	4,473	16,603	28,777	28,977	29,162	29,335	29,509	29,669	213,569
27	ST Debt Return	94	96	97	99	101	376	651	656	660	664	668	671	4,832
28	Equity Return	9,860	10,046	10,226	10,408	10,626	39,442	68,360	68,836	69,275	69,686	70,100	70,481	507,348
29														
30	Tax Depreciation & Removal													
31	Avoided Tax Interest	6,503	6,611	6,717	6,823	6,954	25,884	44,885	45,188	45,473	45,740	46,005	46,254	333,035
32	Book Depreciation													
33	AFUDC													
34														
35	Annual Deferred Tax	(11,336)	(11,336)	(11,336)	(11,336)	(11,336)	(11,336)	(11,336)	(11,336)	(11,336)	(11,336)	(11,336)	(11,336)	(136,034)
36	Operating Expense													
37	Property Tax Expense													
38														
39	Current Income Tax Requirement	3,547	3,755	3,956	4,160	4,406	38,096	71,908	72,457	72,969	73,447	73,925	74,371	496,997
40	Production Tax Credit													
41														
42	**Total Revenue Requirements**	6,316	6,789	7,248	7,712	8,270	83,180	158,360	159,589	160,729	161,796	162,865	163,857	1,086,712
43														
44	Jurisdictional Allocation Factor *	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%
45	Interchange Allocation Factor	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%
46	**State Jurisdictional Revenue Requirement**	4,630	4,977	5,313	5,653	6,063	60,976	116,088	116,988	117,825	118,606	119,390	120,117	796,626

* Note: State Jurisdictional Requirements are calculated using Energy and Demand allocators applied to the separate Production and Transmission components of the project.

Line No.	NSPM Rider Revenue Requirements calculation - MN RES *Amounts in $ Dollars*	Jan - 2019	Feb - 2019	Mar - 2019	Apr - 2019	May - 2019	Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	2019
	Freeborn													
2	**Cap Structure and Tax Rates**													
3	LT Debt Cost	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%
4	LT Debt Ratio	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%
5	LT Debt Weighted Cost Rounded	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%
6	ST Debt Cost	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%
7	ST Debt Ratio	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%
8	ST Debt Weighted Cost Rounded	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%
9	Equity Cost	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
10	Equity Ratio	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%
11	Equity Weighted Cost Rounded	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%
12														
13	Fed Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
14	State Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
15	State Composite Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
16														
17	**Revenue Requirement Calculation**													
18	CWIP	16,088,269	16,151,682	16,215,913	16,280,623	16,361,390	16,798,632	16,947,027	16,869,748	17,064,773	47,549,562	48,351,106	49,047,954	49,047,954
19	Plant Investment								368,942	368,942	368,942	368,942	368,942	368,942
20	Depreciation Reserve								688	2,067	3,445	4,824	6,203	6,203
21	Accumulated Deferred Taxes	(170,476)	(200,102)	(229,728)	(259,354)	(288,979)	(318,605)	(348,231)	(377,857)	(407,482)	(437,108)	(466,734)	(496,359)	(496,359)
22	Rate Base	16,258,746	16,351,784	16,445,641	16,539,977	16,650,370	17,117,237	17,295,258	17,615,859	17,839,131	48,352,167	49,181,958	49,907,053	49,907,053
23	Rate Base from Previous Period	16,151,738	16,258,746	16,351,784	16,445,641	16,539,977	16,650,370	17,117,237	17,295,258	17,615,859	17,839,131	48,352,167	49,181,958	49,181,958
24	Average Rate Base	16,205,242	16,305,265	16,398,712	16,492,809	16,595,173	16,883,803	17,206,247	17,455,558	17,727,495	33,095,649	48,767,063	49,544,506	49,544,506
25														
26	LT Debt Return	29,440	29,621	29,791	29,962	30,148	30,672	31,258	31,711	32,205	60,124	88,593	90,006	513,531
27	ST Debt Return	945	951	957	962	968	985	1,004	1,018	1,034	1,931	2,845	2,890	16,490
28	Equity Return	70,898	71,336	71,744	72,156	72,604	73,867	75,277	76,368	77,558	144,793	213,356	216,757	1,236,714
29														
30	Tax Depreciation & Removal													
31	Avoided Tax Interest	49,293	49,658	50,005	50,354	50,730	51,676	52,728	53,380	54,105	101,109	149,182	151,925	864,144
32	Book Depreciation								688	1,379	1,379	1,379	1,379	6,203
33	AFUDC													
34														
35	Annual Deferred Tax	(29,626)	(29,626)	(29,626)	(29,626)	(29,626)	(29,626)	(29,626)	(29,626)	(29,626)	(29,626)	(29,626)	(29,626)	(355,509)
36	Operating Expense													
37	Property Tax Expense													
38														
39	Current Income Tax Requirement	63,904	64,470	65,003	65,540	66,122	67,680	69,418	71,133	72,972	153,580	235,879	240,215	1,235,915
40	Production Tax Credit													
41														
42	**Total Revenue Requirements**	135,561	136,753	137,870	138,995	140,216	143,578	147,331	151,292	155,521	332,181	512,426	521,621	2,653,344
43														
44	Jurisdictional Allocation Factor *	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%
45	Interchange Allocation Factor	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%
46	**State Jurisdictional Revenue Requirement**	99,141	100,013	100,830	101,653	102,546	105,005	107,749	110,646	113,739	242,938	374,759	381,485	1,940,502

* Note: State Jurisdictional Requirements are calculated using Energy and Demand allocators applied to the separate Production and Transmission components of the project.

Line No.	NSPM Rider Revenue Requirements calculation - MN RES *Amounts in $ Dollars*	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	2017
	Lake Benton													
2	**Cap Structure and Tax Rates**													
3	LT Debt Cost	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%
4	LT Debt Ratio	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%	46.04%
5	LT Debt Weighted Cost Rounded	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%
6	ST Debt Cost	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%
7	ST Debt Ratio	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%
8	ST Debt Weighted Cost Rounded	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
9	Equity Cost	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
10	Equity Ratio	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%
11	Equity Weighted Cost Rounded	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%
12														
13	Fed Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
14	State Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
15	State Composite Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
16														
17	**Revenue Requirement Calculation**													
18	CWIP										291,612	299,802	306,704	306,704
19	Plant Investment													
20	Depreciation Reserve													
21	Accumulated Deferred Taxes	(71)	(142)	(213)	(284)	(355)	(426)	(497)	(568)	(640)	(711)	(782)	(853)	(853)
22	Rate Base	71	142	213	284	355	426	497	568	640	292,323	300,584	307,557	307,557
23	Rate Base from Previous Period		71	142	213	284	355	426	497	568	640	292,323	300,584	300,584
24	Average Rate Base	36	107	178	249	320	391	462	533	604	146,481	296,453	304,070	304,070
25														
26	LT Debt Return	0	0	0	0	1	1	1	1	1	270	546	560	1,381
27	ST Debt Return	0	0	0	0	0	0	0	0	0	6	12	13	31
28	Equity Return	0	0	1	1	1	2	2	2	3	641	1,297	1,330	3,281
29														
30	Tax Depreciation & Removal													
31	Avoided Tax Interest										408	828	852	2,088
32	Book Depreciation													
33	AFUDC													
34														
35	Annual Deferred Tax	(71)	(71)	(71)	(71)	(71)	(71)	(71)	(71)	(71)	(71)	(71)	(71)	(853)
36	Operating Expense													
37	Property Tax Expense													
38														
39	Current Income Tax Requirement	(50)	(50)	(50)	(49)	(49)	(49)	(49)	(48)	(48)	690	1,449	1,489	3,186
40	Production Tax Credit													
41														
42	**Total Revenue Requirements**	(121)	(120)	(120)	(119)	(118)	(118)	(117)	(116)	(116)	1,535	3,234	3,321	7,027
43														
44	Jurisdictional Allocation Factor *	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%	87.3858%
45	Interchange Allocation Factor	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%	84.2464%
46	**State Jurisdictional Revenue Requirement**	(89)	(88)	(88)	(88)	(87)	(87)	(86)	(86)	(85)	1,130	2,381	2,445	5,173

* Note: State Jurisdictional Requirements are calculated using Energy and Demand allocators applied to the separate Production and Transmission components of the project.

Line No.	NSPM Rider Revenue Requirements calculation - MN RES *Amounts in $ Dollars*	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	2018
	Lake Benton													
2	**Cap Structure and Tax Rates**													
3	LT Debt Cost	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%
4	LT Debt Ratio	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%	46.41%
5	LT Debt Weighted Cost Rounded	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%
6	ST Debt Cost	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%	4.45%
7	ST Debt Ratio	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%	1.09%
8	ST Debt Weighted Cost Rounded	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
9	Equity Cost	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
10	Equity Ratio	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%
11	Equity Weighted Cost Rounded	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%
12														
13	Fed Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
14	State Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
15	State Composite Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
16														
17	**Revenue Requirement Calculation**													
18	CWIP	11,558,419	11,566,577	11,577,161	11,588,878	11,603,652	20,995,094	21,013,096	21,032,956	21,054,341	21,081,962	21,110,289	21,140,208	21,140,208
19	Plant Investment													
20	Depreciation Reserve													
21	Accumulated Deferred Taxes	(20,235)	(39,618)	(59,001)	(78,383)	(97,766)	(117,149)	(136,531)	(155,914)	(175,296)	(194,679)	(214,062)	(233,444)	(233,444)
22	Rate Base	11,578,654	11,606,195	11,636,162	11,667,261	11,701,418	21,112,243	21,149,627	21,188,869	21,229,637	21,276,641	21,324,350	21,373,652	21,373,652
23	Rate Base from Previous Period	307,557	11,578,654	11,606,195	11,636,162	11,667,261	11,701,418	21,112,243	21,149,627	21,188,869	21,229,637	21,276,641	21,324,350	21,324,350
24	Average Rate Base	5,943,105	11,592,424	11,621,178	11,651,712	11,684,340	16,406,830	21,130,935	21,169,248	21,209,253	21,253,139	21,300,496	21,349,001	21,349,001
25														
26	LT Debt Return	10,945	21,349	21,402	21,459	21,519	30,216	38,916	38,987	39,060	39,141	39,228	39,318	361,541
27	ST Debt Return	248	483	484	485	487	684	880	882	884	886	888	890	8,180
28	Equity Return	26,001	50,717	50,843	50,976	51,119	71,780	92,448	92,615	92,790	92,982	93,190	93,402	858,864
29														
30	Tax Depreciation & Removal													
31	Avoided Tax Interest	17,113	33,397	33,521	33,650	33,785	47,444	61,148	61,379	61,615	61,864	62,123	62,386	569,424
32	Book Depreciation													
33	AFUDC													
34														
35	Annual Deferred Tax	(19,383)	(19,383)	(19,383)	(19,383)	(19,383)	(19,383)	(19,383)	(19,383)	(19,383)	(19,383)	(19,383)	(19,383)	(232,592)
36	Operating Expense													
37	Property Tax Expense													
38														
39	Current Income Tax Requirement	16,745	45,675	45,851	46,036	46,232	70,449	94,702	94,983	95,274	95,585	95,914	96,249	843,697
40	Production Tax Credit													
41														
42	**Total Revenue Requirements**	34,557	98,842	99,198	99,574	99,974	153,746	207,564	208,085	208,626	209,211	209,837	210,475	1,839,689
43														
44	Jurisdictional Allocation Factor *	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%	87.1864%
45	Interchange Allocation Factor	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%	84.0798%
46	**State Jurisdictional Revenue Requirement**	25,332	72,457	72,718	72,994	73,287	112,705	152,157	152,539	152,936	153,365	153,823	154,291	1,348,605

* Note: State Jurisdictional Requirements are calculated using Energy and Demand allocators applied to the separate Production and Transmission components of the project.

Line No.	NSPM Rider Revenue Requirements calculation - MN RES *Amounts in $ Dollars*	Jan - 2019	Feb - 2019	Mar - 2019	Apr - 2019	May - 2019	Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	2019
	Lake Benton													
2	**Cap Structure and Tax Rates**													
3	LT Debt Cost	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%
4	LT Debt Ratio	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%	45.81%
5	LT Debt Weighted Cost Rounded	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%
6	ST Debt Cost	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%
7	ST Debt Ratio	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%
8	ST Debt Weighted Cost Rounded	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%
9	Equity Cost	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
10	Equity Ratio	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%
11	Equity Weighted Cost Rounded	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%
12														
13	Fed Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
14	State Tax Rate	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%
15	State Composite Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
16														
17	**Revenue Requirement Calculation**													
18	CWIP	21,217,878	21,311,466	21,480,393	21,667,917	29,446,870	29,629,085	36,019,078	71,876,616	102,748,719				
19	Plant Investment										146,801,880	150,933,401	166,545,134	166,545,134
20	Depreciation Reserve										265,467	803,871	1,377,979	1,377,979
21	Accumulated Deferred Taxes	2,020,070	4,273,584	6,527,098	8,780,612	11,034,125	13,287,639	15,541,153	17,794,667	20,048,181	22,301,695	24,555,209	26,808,723	26,808,723
22	Rate Base	19,197,808	17,037,882	14,953,295	12,887,305	18,412,745	16,341,446	20,477,925	54,081,948	82,700,538	124,234,718	125,574,321	138,358,432	138,358,432
23	Rate Base from Previous Period	21,373,652	19,197,808	17,037,882	14,953,295	12,887,305	18,412,745	16,341,446	20,477,925	54,081,948	82,700,538	124,234,718	125,574,321	125,574,321
24	Average Rate Base	20,285,730	18,117,845	15,995,589	13,920,300	15,650,025	17,377,095	18,409,685	37,279,936	68,391,243	103,467,628	124,904,519	131,966,376	131,966,376
25														
26	LT Debt Return	36,852	32,914	29,059	25,289	28,431	31,568	33,444	67,725	124,244	187,966	226,910	239,739	1,064,142
27	ST Debt Return	1,183	1,057	933	812	913	1,014	1,074	2,175	3,989	6,036	7,286	7,698	34,170
28	Equity Return	88,750	79,266	69,981	60,901	68,469	76,025	80,542	163,100	299,212	452,671	546,457	577,353	2,562,726
29														
30	Tax Depreciation & Removal	5,729,943	5,729,943	5,729,943	5,729,943	5,729,943	5,729,943	5,729,943	5,729,943	5,729,943	5,729,943	5,729,943	5,729,943	68,759,312
31	Avoided Tax Interest	66,412	66,877	67,481	68,232	80,602	93,003	103,320	168,134	270,522	192,868			1,177,451
32	Book Depreciation										265,467	538,405	574,107	1,377,979
33	AFUDC													
34														
35	Annual Deferred Tax	2,253,514	2,253,514	2,253,514	2,253,514	2,253,514	2,253,514	2,253,514	2,253,514	2,253,514	2,253,514	2,253,514	2,253,514	27,042,168
36	Operating Expense	31,236	31,236	31,236	31,236	31,236	31,236	31,236	31,236	31,236	31,236	31,236	31,236	374,829
37	Property Tax Expense													
38														
39	Current Income Tax Requirement	(2,343,524)	(2,349,888)	(2,356,013)	(2,361,890)	(2,347,822)	(2,333,740)	(2,323,272)	(2,219,286)	(2,050,997)	(1,810,192)	(1,687,517)	(1,640,525)	(25,824,666)
40	Production Tax Credit												(1,697,111)	(1,697,111)
41														
42	**Total Revenue Requirements**	68,012	48,098	28,709	9,861	34,741	59,616	76,538	298,464	661,198	1,386,697	1,916,291	346,011	4,934,235
43														
44	Jurisdictional Allocation Factor *	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%	87.1291%
45	Interchange Allocation Factor	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%	83.9377%
46	**State Jurisdictional Revenue Requirement**	49,779	35,215	21,035	7,251	25,446	43,639	56,014	218,318	483,600	1,014,188	1,401,502	253,178	3,609,165

* Note: State Jurisdictional Requirements are calculated using Energy and Demand allocators applied to the separate Production and Transmission components of the project.

Shaded Wind Farms are recovered through Base Rates and are included in the PTC True-up Calculation below.

Line No.			First Month of Credit	Final Month of Credit	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	Fcst Oct-17	Fcst Nov-17	Fcst Dec-17	Total 2017
1		Grand Meadows	Nov-08	Oct-18	24,354,752	34,461,149	34,843,947	27,370,239	26,833,007	21,365,221	11,532,783	14,501,222	22,334,083	29,535,340	34,655,390	25,593,290	**307,380,422**
2		Nobles	Dec-10	Nov-20	58,312,107	70,411,456	78,488,528	70,331,665	61,190,343	46,032,892	32,040,574	25,501,131	48,660,017	64,635,210	78,249,490	62,804,160	**696,657,573**
3		Pleasant Valley	Nov-15	Oct-25	67,463,343	84,175,308	83,346,808	71,919,289	71,176,718	58,458,023	37,140,738	44,118,505	67,225,514	76,156,850	80,261,680	67,989,480	**809,432,256**
4		Border Winds	Dec-15	Nov-25	57,445,832	52,793,483	57,161,713	52,530,978	43,570,079	50,334,971	46,440,839	29,715,528	59,287,967	50,868,990	55,091,610	41,535,580	**596,777,570**
5	**Wind Production**	Courtenay	Dec-16	Nov-26	81,303,284	68,576,910	66,527,207	61,621,432	69,473,742	59,963,782	43,770,898	34,745,337	61,504,892	74,763,135	69,636,685	69,115,183	**761,002,486**
6	**(kWh)**	Blazing Star I	Dec-19	Nov-29													
7		Foxtail	Dec-19	Nov-29													
8	**A**	Crowned Ridge	Dec-19	Nov-29													
9		Lake Benton	Dec-19	Nov-29													
10		Blazing Star II	Dec-20	Nov-30													
11		Freeborn	Dec-20	Nov-30													
12		**Total kWh Wind Production**			**288,879,318**	**310,418,305**	**320,368,203**	**283,773,603**	**272,243,887**	**236,154,888**	**170,925,833**	**148,581,723**	**259,012,473**	**295,959,525**	**317,894,855**	**267,037,693**	**3,171,250,306**
13																	
14																	
15		**B** PTC Factor per kWh		$0.024													
16																	
17		Grand Meadows			584,514	827,068	836,255	656,886	643,992	512,765	276,787	348,029	536,018	708,848	831,729	614,239	**7,377,130**
18		Nobles			1,399,491	1,689,875	1,883,725	1,687,960	1,468,568	1,104,789	768,974	612,027	1,167,840	1,551,245	1,877,988	1,507,300	**16,719,782**
19		Pleasant Valley			1,619,120	2,020,207	2,000,323	1,726,063	1,708,241	1,402,993	891,378	1,058,844	1,613,412	1,827,764	1,926,280	1,631,748	**19,426,374**
20		Border Winds			1,378,700	1,267,044	1,371,881	1,260,743	1,045,682	1,208,039	1,114,580	713,173	1,422,911	1,220,856	1,322,199	996,854	**14,322,662**
21	**PTC Value**	Courtenay			1,951,279	1,645,846	1,596,653	1,478,914	1,667,370	1,439,131	1,050,502	833,888	1,476,117	1,794,315	1,671,280	1,658,764	**18,264,060**
22	**($0.024 per kWh)**	Blazing Star I			-	-	-	-	-	-	-	-	-	-	-	-	**-**
23		Foxtail			-	-	-	-	-	-	-	-	-	-	-	-	**-**
24	**C = A x B**	Crowned Ridge			-	-	-	-	-	-	-	-	-	-	-	-	**-**
25		Lake Benton			-	-	-	-	-	-	-	-	-	-	-	-	**-**
26		Blazing Star II			-	-	-	-	-	-	-	-	-	-	-	-	**-**
27		Freeborn			-	-	-	-	-	-	-	-	-	-	-	-	**-**
28		**Total PTC Value**			**6,933,104**	**7,450,039**	**7,688,837**	**6,810,566**	**6,533,853**	**5,667,717**	**4,102,220**	**3,565,961**	**6,216,299**	**7,103,029**	**7,629,477**	**6,408,905**	**76,110,007**
29																	
30																	
31		**D** RR Tax Gross-up		1.705611462													
32																	
33		Grand Meadows			996,954	1,410,656	1,426,326	1,120,392	1,098,400	874,578	472,091	593,603	914,238	1,209,020	1,418,607	1,047,653	**12,582,518**
34		Nobles			2,386,987	2,882,270	3,212,902	2,879,004	2,504,807	1,884,341	1,311,570	1,043,881	1,991,882	2,645,821	3,203,117	2,570,868	**28,517,451**
35		Pleasant Valley			2,761,590	3,445,689	3,411,775	2,943,993	2,913,596	2,392,960	1,520,344	1,805,977	2,751,855	3,117,456	3,285,486	2,783,127	**33,133,846**
36		Border Winds			2,351,526	2,161,084	2,339,896	2,150,338	1,783,527	2,060,446	1,901,041	1,216,396	2,426,934	2,082,306	2,255,157	1,700,245	**24,428,896**
37	**PTC Revenue**	Courtenay		*Att. G, pg. 7-9*	3,328,124	2,807,174	2,723,270	2,522,453	2,843,885	2,454,598	1,791,748	1,422,289	2,517,683	3,060,405	2,850,555	2,829,208	**31,151,389**
38	**Requirements**	Blazing Star I		*Att. G, pg. 1-3*	-	-	-	-	-	-	-	-	-	-	-	-	**-**
39		Foxtail		*Att. G, pg. 16-18*	-	-	-	-	-	-	-	-	-	-	-	-	**-**
40	**E = C x D**	Crowned Ridge		*Att. G, pg. 10-12*	-	-	-	-	-	-	-	-	-	-	-	-	**-**
41		Lake Benton		*Att. G, pg. 22-24*	-	-	-	-	-	-	-	-	-	-	-	-	**-**
42		Blazing Star II		*Att. G, pg. 4-6*	-	-	-	-	-	-	-	-	-	-	-	-	**-**
43		Freeborn		*Att. G, pg. 19-21*	-	-	-	-	-	-	-	-	-	-	-	-	**-**
44		**Total PTC Value**			**11,825,181**	**12,706,872**	**13,114,168**	**11,616,180**	**11,144,215**	**9,666,924**	**6,996,793**	**6,082,145**	**10,602,591**	**12,115,007**	**13,012,923**	**10,931,101**	**129,814,101**
45																	
46																	
47		**F** '17 Energy Allocator		73.4132%													
48		**F** '18 Energy Allocator		73.1627%													
49		**F** '19 Energy Allocator		73.1290%													
50																	
51		Grand Meadows			731,895	1,035,607	1,047,111	822,515	806,370	642,056	346,577	435,783	671,171	887,579	1,041,444	769,115	**9,237,224**
52		Nobles			1,752,363	2,115,966	2,358,693	2,113,568	1,838,858	1,383,355	962,865	766,346	1,462,304	1,942,381	2,351,510	1,887,355	**20,935,562**
53		Pleasant Valley			2,027,371	2,529,589	2,504,691	2,161,278	2,138,963	1,756,748	1,116,133	1,325,825	2,020,223	2,288,623	2,411,979	2,043,182	**24,324,604**
54		Border Winds			1,726,330	1,586,520	1,717,792	1,578,631	1,309,344	1,512,638	1,395,614	892,994	1,781,689	1,528,686	1,655,582	1,248,204	**17,934,024**
55	**MN Jur**	**Sub Total Base Rate Wind Farms**			6,237,958	7,267,682	7,628,287	6,675,992	6,093,535	5,294,796	3,821,189	3,420,947	5,935,387	6,647,270	7,460,515	5,947,856	**72,431,414**
56		Courtenay			2,443,281	2,060,835	1,999,238	1,851,813	2,087,786	1,801,998	1,315,378	1,044,147	1,848,310	2,246,740	2,092,683	2,077,011	**22,869,219**
57	**PTC Value**	Blazing Star I			-	-	-	-	-	-	-	-	-	-	-	-	**-**
58	**G = E x F**	Foxtail			-	-	-	-	-	-	-	-	-	-	-	-	**-**
59		Crowned Ridge			-	-	-	-	-	-	-	-	-	-	-	-	**-**
60		Lake Benton			-	-	-	-	-	-	-	-	-	-	-	-	**-**
61		Blazing Star II			-	-	-	-	-	-	-	-	-	-	-	-	**-**
62		Freeborn			-	-	-	-	-	-	-	-	-	-	-	-	**-**
63		**Total MN Jur PTC Value**			**8,681,239**	**9,328,517**	**9,627,525**	**8,527,805**	**8,181,320**	**7,096,794**	**5,136,567**	**4,465,095**	**7,783,697**	**8,894,009**	**9,553,198**	**8,024,867**	**95,300,634**
64																	
65																	
66		Grand Meadows			890,491	530,104	664,240	679,351	675,119	496,938	440,565	313,168	487,370	731,032	736,966	608,879	**7,254,223**
67		Nobles			1,490,055	1,168,124	1,378,712	1,425,770	1,556,410	1,122,653	925,520	765,325	1,099,354	1,561,286	1,628,515	1,315,738	**15,437,462**
68	**H**	Pleasant Valley			1,943,017	1,256,973	1,450,104	1,507,926	1,507,006	1,108,577	1,003,122	713,828	1,143,606	1,613,657	1,622,305	1,329,262	**16,199,383**
69		Border Winds			1,134,360	975,614	995,647	1,286,597	1,176,841	866,249	726,685	595,516	835,866	1,179,187	1,257,295	938,723	**11,968,580**
70		**Total Base Rate Test Year PTC Forecast**			**5,457,923**	**3,930,815**	**4,488,703**	**4,899,644**	**4,915,376**	**3,594,417**	**3,095,892**	**2,387,837**	**3,566,196**	**5,085,162**	**5,245,081**	**4,192,602**	**50,859,648**
71																	
72	**Base Rate Test Year**	Test Year Allocators:															
73	**PTC Forecast from**	**I** '17 Energy Allocator		72.8410%													
74		**I** '18 Energy Allocator		72.5794%													
75	**15-826**	**I** '19 Energy Allocator		72.3290%													
76		**J** RR Tax Gross-up		1.705611462													
77																	
78		Grand Meadows			1,106,333	658,593	825,242	844,015	838,758	617,388	547,351	389,075	605,501	908,223	915,595	756,462	**9,012,537**
79		Nobles			1,851,222	1,451,260	1,712,891	1,771,355	1,933,660	1,394,767	1,149,852	950,828	1,365,821	1,939,718	2,023,242	1,634,653	**19,179,269**
80	**K = H x I x J**	Pleasant Valley			2,413,975	1,561,644	1,801,587	1,873,424	1,872,281	1,377,279	1,246,264	886,849	1,420,799	2,004,783	2,015,527	1,651,455	**20,125,868**
81		Border Winds			1,409,312	1,212,088	1,236,977	1,598,449	1,462,089	1,076,215	902,822	739,860	1,038,467	1,465,004	1,562,044	1,166,255	**14,869,582**
82		**Total MN Jur RR Base Rate Test Year PTC Forecast**			**6,780,841**	**4,883,585**	**5,576,697**	**6,087,243**	**6,106,789**	**4,465,649**	**3,846,289**	**2,966,612**	**4,430,588**	**6,317,728**	**6,516,409**	**5,208,825**	**63,187,255**
83																	
84																	
85	**PTC True-up**	Grand Meadows			374,437	(377,014)	(221,869)	21,500	32,387	(24,667)	200,775	(46,707)	(65,670)	20,644	(125,849)	(12,653)	**(224,687)**
86	**(Actual PTCs vs**	Nobles			98,859	(664,706)	(645,802)	(342,213)	94,802	11,412	186,987	184,483	(96,483)	(2,663)	(328,267)	(252,702)	**(1,756,294)**
87	**Base Rate Fcst)**	Pleasant Valley			386,604	(967,945)	(703,104)	(287,854)	(266,681)	(379,468)	130,131	(438,975)	(599,425)	(283,840)	(396,452)	(391,727)	**(4,198,736)**
88		Border Winds			(317,018)	(374,432)	(480,815)	19,817	152,746	(436,424)	(492,792)	(153,134)	(743,221)	(63,682)	(93,538)	(81,949)	**(3,064,442)**
89	**L = K - G**	**Total PTC True-up**			**542,882**	**(2,384,097)**	**(2,051,591)**	**(588,749)**	**13,254**	**(829,147)**	**25,101**	**(454,335)**	**(1,504,799)**	**(329,542)**	**(944,106)**	**(739,031)**	**(9,244,159)**

Att. C

Shaded Wind Farms are recovered through Base Rates and are included in the PTC True-up Calculation below.

Line No.			First Month of Credit	Final Month of Credit	Fcst Jan-18	Fcst Feb-18	Fcst Mar-18	Fcst Apr-18	Fcst May-18	Fcst Jun-18	Fcst Jul-18	Fcst Aug-18	Fcst Sep-18	Fcst Oct-18	Fcst Nov-18	Fcst Dec-18	Total 2018
1		Grand Meadows	Nov-08	Oct-18	30,037,770	27,865,140	32,996,080	35,166,050	25,170,170	20,134,360	14,889,190	11,104,770	23,626,220	29,535,340	-	-	**250,525,090**
2		Nobles	Dec-10	Nov-20	70,080,620	60,262,410	71,101,130	82,901,880	61,442,040	48,073,130	38,158,450	28,931,670	53,511,110	64,635,210	78,249,490	62,804,160	**720,151,300**
3		Pleasant Valley	Nov-15	Oct-25	75,462,340	68,245,710	81,300,310	85,096,930	68,850,670	54,518,550	43,373,790	34,018,840	67,140,880	76,156,850	80,261,680	67,989,480	**802,416,030**
4		Border Winds	Dec-15	Nov-25	61,414,450	43,342,460	66,505,060	62,281,780	54,402,540	47,566,750	32,382,240	49,509,220	54,511,300	50,868,990	55,091,610	41,535,580	**619,411,980**
5	**Wind Production**	Courtenay	Dec-16	Nov-26	78,983,310	62,952,260	80,317,070	83,669,990	69,523,550	61,449,480	47,331,630	49,447,150	67,877,450	79,535,250	74,081,580	73,526,790	**828,695,510**
6	**(kWh)**	Blazing Star I	Dec-19	Nov-29													
7		Foxtail	Dec-19	Nov-29													
8	**A**	Crowned Ridge	Dec-19	Nov-29													
9		Lake Benton	Dec-19	Nov-29													
10		Blazing Star II	Dec-20	Nov-30													
11		Freeborn	Dec-20	Nov-30													
12		**Total kWh Wind Production**			**315,978,490**	**262,667,980**	**332,219,650**	**349,116,630**	**279,388,970**	**231,742,270**	**176,135,300**	**173,011,650**	**266,666,960**	**300,731,640**	**287,684,360**	**245,856,010**	**3,221,199,910**
13																	
14																	
15			**B** PTC Factor per kWh	$0.024													
16																	
17		Grand Meadows			720,906	668,763	791,906	843,985	604,084	483,225	357,341	266,514	567,029	708,848	-	-	**6,012,602**
18		Nobles			1,681,935	1,446,298	1,706,427	1,989,645	1,474,609	1,153,755	915,803	694,360	1,284,267	1,551,245	1,877,988	1,507,300	**17,283,631**
19		Pleasant Valley			1,811,096	1,637,897	1,951,207	2,042,326	1,652,416	1,308,445	1,040,971	816,452	1,611,381	1,827,764	1,926,280	1,631,748	**19,257,985**
20		Border Winds			1,473,947	1,040,219	1,596,121	1,494,763	1,305,661	1,141,602	777,174	1,188,221	1,308,271	1,220,856	1,322,199	996,854	**14,865,888**
21	**PTC Value**	Courtenay			1,895,599	1,510,854	1,927,610	2,008,080	1,668,565	1,474,788	1,135,959	1,186,732	1,629,059	1,908,846	1,777,958	1,764,643	**19,888,692**
22	**($0.024 per kWh)**	Blazing Star I			-	-	-	-	-	-	-	-	-	-	-	-	-
23		Foxtail			-	-	-	-	-	-	-	-	-	-	-	-	-
24	**C = A x B**	Crowned Ridge			-	-	-	-	-	-	-	-	-	-	-	-	-
25		Lake Benton			-	-	-	-	-	-	-	-	-	-	-	-	-
26		Blazing Star II			-	-	-	-	-	-	-	-	-	-	-	-	-
27		Freeborn			-	-	-	-	-	-	-	-	-	-	-	-	-
28		**Total PTC Value**			**7,583,484**	**6,304,032**	**7,973,272**	**8,378,799**	**6,705,335**	**5,561,814**	**4,227,247**	**4,152,280**	**6,400,007**	**7,217,559**	**6,904,425**	**5,900,544**	**77,308,798**
29																	
30																	
31			**D** RR Tax Gross-up	1.705611462													
32																	
33		Grand Meadows			1,229,586	1,140,650	1,350,684	1,439,511	1,030,333	824,193	609,484	454,570	967,132	1,209,020	-	-	**10,255,163**
34		Nobles			2,868,727	2,466,822	2,910,502	3,393,562	2,515,110	1,967,858	1,562,004	1,184,309	2,190,460	2,645,821	3,203,117	2,570,868	**29,479,159**
35		Pleasant Valley			3,089,026	2,793,616	3,328,002	3,483,415	2,818,380	2,231,699	1,775,492	1,392,550	2,748,390	3,117,456	3,285,486	2,783,127	**32,846,639**
36		Border Winds			2,513,981	1,774,210	2,722,363	2,549,484	2,226,950	1,947,129	1,325,556	2,026,644	2,231,402	2,082,306	2,255,157	1,700,245	**25,355,428**
37	**PTC Revenue**	Courtenay		*Att. G, pg. 7-9*	3,233,156	2,576,930	3,287,753	3,425,004	2,845,924	2,515,414	1,937,505	2,024,103	2,778,541	3,255,750	3,032,505	3,009,795	**33,922,381**
38	**Requirements**	Blazing Star I		*Att. G, pg. 1-3*	-	-	-	-	-	-	-	-	-	-	-	-	-
39		Foxtail		*Att. G, pg. 16-18*	-	-	-	-	-	-	-	-	-	-	-	-	-
40	**E = C x D**	Crowned Ridge		*Att. G, pg. 10-12*	-	-	-	-	-	-	-	-	-	-	-	-	-
41		Lake Benton		*Att. G, pg. 22-24*	-	-	-	-	-	-	-	-	-	-	-	-	-
42		Blazing Star II		*Att. G, pg. 4-6*	-	-	-	-	-	-	-	-	-	-	-	-	-
43		Freeborn		*Att. G, pg. 19-21*	-	-	-	-	-	-	-	-	-	-	-	-	-
44		**Total PTC Value**			**12,934,477**	**10,752,228**	**13,599,303**	**14,290,976**	**11,436,697**	**9,486,295**	**7,210,041**	**7,082,176**	**10,915,925**	**12,310,352**	**11,776,266**	**10,064,036**	**131,858,772**
45																	
46																	
47			**F** '17 Energy Allocator	73.4132%													
48			**F** '18 Energy Allocator	73.1627%													
49			**F** '19 Energy Allocator	73.1290%													
50																	
51		Grand Meadows			899,599	834,531	988,197	1,053,185	753,820	603,002	445,915	332,576	707,580	884,552	-	-	**7,502,957**
52		Nobles			2,098,839	1,804,794	2,129,402	2,482,822	1,840,123	1,439,739	1,142,805	866,472	1,602,600	1,935,755	2,343,488	1,880,917	**21,567,758**
53		Pleasant Valley			2,260,016	2,043,886	2,434,857	2,548,562	2,062,004	1,632,772	1,298,998	1,018,828	2,010,797	2,280,816	2,403,751	2,036,212	**24,031,498**
54		Border Winds			1,839,297	1,298,060	1,991,755	1,865,272	1,629,298	1,424,573	969,813	1,482,748	1,632,555	1,523,472	1,649,935	1,243,946	**18,550,723**
55	**MN Jur**	**Sub Total Base Rate Wind Farms**			7,097,751	5,981,271	7,544,212	7,949,842	6,285,244	5,100,086	3,857,532	3,700,624	5,953,532	6,624,594	6,397,174	5,161,075	**71,652,936**
56		Courtenay			2,365,465	1,885,353	2,405,410	2,505,826	2,082,156	1,840,346	1,417,531	1,480,889	2,032,857	2,381,995	2,218,664	2,202,048	**24,818,540**
57	**PTC Value**	Blazing Star I			-	-	-	-	-	-	-	-	-	-	-	-	-
58	**G = E x F**	Foxtail			-	-	-	-	-	-	-	-	-	-	-	-	-
59		Crowned Ridge			-	-	-	-	-	-	-	-	-	-	-	-	-
60		Lake Benton			-	-	-	-	-	-	-	-	-	-	-	-	-
61		Blazing Star II			-	-	-	-	-	-	-	-	-	-	-	-	-
62		Freeborn			-	-	-	-	-	-	-	-	-	-	-	-	-
63		**Total MN Jur PTC Value**			**9,463,216**	**7,866,624**	**9,949,622**	**10,455,668**	**8,367,399**	**6,940,432**	**5,275,063**	**5,181,513**	**7,986,389**	**9,006,589**	**8,615,837**	**7,363,123**	**96,471,476**
64																	
65																	
66		Grand Meadows			890,491	530,104	664,240	679,351	682,249	496,938	440,565	313,168	493,902	733,447	-	-	**5,924,455**
67		Nobles			1,490,055	1,168,124	1,378,712	1,425,770	1,561,539	1,122,653	925,520	765,325	1,107,933	1,561,884	1,628,492	1,315,738	**15,451,745**
68	**H**	Pleasant Valley			1,943,017	1,256,973	1,450,104	1,507,926	1,510,778	1,108,577	1,003,122	713,828	1,145,009	1,613,657	1,622,305	1,329,262	**16,204,558**
69		Border Winds			1,134,360	975,614	995,647	1,286,597	1,179,233	866,249	726,685	595,516	845,342	1,179,187	1,257,295	938,722	**11,980,447**
70		**Total Base Rate Test Year PTC Forecast**			**5,457,923**	**3,930,815**	**4,488,703**	**4,899,644**	**4,933,799**	**3,594,417**	**3,095,892**	**2,387,837**	**3,592,186**	**5,088,175**	**4,508,092**	**3,583,722**	**49,561,205**
71																	
72	**Base Rate Test Year**		Test Year Allocators:														
73	**PTC Forecast from**		**I** '17 Energy Allocator	72.8410%													
74			**I** '18 Energy Allocator	72.5794%													
75	**15-826**		**I** '19 Energy Allocator	72.3290%													
76			**J** RR Tax Gross-up	1.705611462													
77																	
78		Grand Meadows			1,102,358	656,227	822,277	840,983	844,571	615,170	545,385	387,677	611,412	907,950	-	-	**7,334,012**
79		Nobles			1,844,571	1,446,046	1,706,738	1,764,992	1,933,063	1,389,757	1,145,721	947,412	1,371,534	1,933,490	2,015,946	1,628,781	**19,128,051**
80	**K = H x I x J**	Pleasant Valley			2,405,303	1,556,034	1,795,115	1,866,694	1,870,225	1,372,332	1,241,787	883,663	1,417,432	1,997,581	2,008,287	1,645,522	**20,059,975**
81		Border Winds			1,404,249	1,207,734	1,232,533	1,592,706	1,459,798	1,072,348	899,579	737,202	1,046,467	1,459,741	1,556,433	1,162,064	**14,830,856**
82		**Total MN Jur RR Base Rate Test Year PTC Forecast**			**6,756,482**	**4,866,041**	**5,556,663**	**6,065,376**	**6,107,657**	**4,449,607**	**3,832,472**	**2,955,955**	**4,446,845**	**6,298,762**	**5,580,665**	**4,436,367**	**61,352,893**
83																	
84																	
85	**PTC True-up**	Grand Meadows			202,759	(178,304)	(165,920)	(212,202)	90,751	12,168	99,470	55,102	(96,168)	23,398	-	-	**(168,946)**
86	**(Actual PTCs vs**	Nobles			(254,268)	(358,748)	(422,665)	(717,831)	92,940	(49,982)	2,917	80,940	(231,066)	(2,265)	(327,542)	(252,136)	**(2,439,707)**
87	**Base Rate Fcst)**	Pleasant Valley			145,287	(487,851)	(639,742)	(681,867)	(191,779)	(260,440)	(57,212)	(135,165)	(593,366)	(283,235)	(395,464)	(390,690)	**(3,971,523)**
88		Border Winds			(435,048)	(90,326)	(759,222)	(272,566)	(169,499)	(352,225)	(70,234)	(745,546)	(586,088)	(63,730)	(93,502)	(81,882)	**(3,719,867)**
89	**L = K - G**	**Total PTC True-up**			**(341,269)**	**(1,115,230)**	**(1,987,549)**	**(1,884,466)**	**(177,587)**	**(650,479)**	**(25,060)**	**(744,669)**	**(1,506,687)**	**(325,832)**	**(816,509)**	**(724,708)**	**(10,300,043)**

Att. D

Shaded Wind Farms are recovered through Base Rates and are included in the PTC True-up Calculation below.

Line No.			First Month of Credit	Final Month of Credit	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total 2019
					Fcst	*Fcst*	*Fcst*	*Fcst*	*Fcst*	*Fcst*	*Fcst*	*Fcst*	*Fcst*	*Fcst*	*Fcst*	*Fcst*	
1		Grand Meadows	Nov-08	Oct-18	-	-	-	-	-	-	-	-	-	-	-	-	**-**
2		Nobles	Dec-10	Nov-20	70,080,620	60,262,410	71,101,130	82,901,880	61,442,040	48,073,130	38,158,450	28,931,670	53,511,110	64,635,210	78,249,490	62,804,160	**720,151,300**
3		Pleasant Valley	Nov-15	Oct-25	75,462,340	68,245,710	81,300,310	85,096,930	68,850,670	54,518,550	43,373,790	34,018,840	67,140,880	76,156,850	80,226,716	67,989,480	**802,381,066**
4		Border Winds	Dec-15	Nov-25	61,414,450	43,342,460	66,505,060	62,281,780	54,402,540	47,566,750	32,382,240	49,509,220	54,511,300	50,868,990	55,091,610	41,535,580	**619,411,980**
5	**Wind Production**	Courtenay	Dec-16	Nov-26	78,983,310	62,952,260	80,317,070	83,669,990	69,523,550	61,449,480	47,331,630	49,447,150	67,877,450	79,535,250	74,030,746	73,526,790	**828,644,676**
6	**(kWh)**	Blazing Star I	Dec-19	Nov-29												73,329,462	**73,329,462**
7	**A**	Foxtail	Dec-19	Nov-29												55,207,866	**55,207,866**
8		Crowned Ridge	Dec-19	Nov-29												122,746,512	**122,746,512**
9		Lake Benton	Dec-19	Nov-29												41,459,017	**41,459,017**
10		Blazing Star II	Dec-20	Nov-30													**-**
11		Freeborn	Dec-20	Nov-30													**-**
12		**Total kWh Wind Production**			**285,940,720**	**234,802,840**	**299,223,570**	**313,950,580**	**254,218,800**	**211,607,910**	**161,246,110**	**161,906,880**	**243,040,740**	**271,196,300**	**287,598,562**	**538,598,867**	**3,263,331,879**
13																	
14																	
15			**B** PTC Factor per kWh	$0.024													
16																	
17		Grand Meadows			-	-	-	-	-	-	-	-	-	-	-	-	**-**
18		Nobles			1,681,935	1,446,298	1,706,427	1,989,645	1,474,609	1,153,755	915,803	694,360	1,284,267	1,551,245	1,877,988	1,507,300	**17,283,631**
19		Pleasant Valley			1,811,096	1,637,897	1,951,207	2,042,326	1,652,416	1,308,445	1,040,971	816,452	1,611,381	1,827,764	1,925,441	1,631,748	**19,257,146**
20		Border Winds			1,473,947	1,040,219	1,596,121	1,494,763	1,305,661	1,141,602	777,174	1,188,221	1,308,271	1,220,856	1,322,199	996,854	**14,865,888**
21	**PTC Value**	Courtenay			1,895,599	1,510,854	1,927,610	2,008,080	1,668,565	1,474,788	1,135,959	1,186,732	1,629,059	1,908,846	1,776,738	1,764,643	**19,887,472**
22	**($0.024 per kWh)**	Blazing Star I			-	-	-	-	-	-	-	-	-	-	-	1,759,907	**1,759,907**
23	**C = A x B**	Foxtail			-	-	-	-	-	-	-	-	-	-	-	1,324,989	**1,324,989**
24		Crowned Ridge			-	-	-	-	-	-	-	-	-	-	-	2,945,916	**2,945,916**
25		Lake Benton			-	-	-	-	-	-	-	-	-	-	-	995,016	**995,016**
26		Blazing Star II			-	-	-	-	-	-	-	-	-	-	-	-	**-**
27		Freeborn			-	-	-	-	-	-	-	-	-	-	-	-	**-**
28		**Total PTC Value**			**6,862,577**	**5,635,268**	**7,181,366**	**7,534,814**	**6,101,251**	**5,078,590**	**3,869,907**	**3,885,765**	**5,832,978**	**6,508,711**	**6,902,365**	**12,926,373**	**78,319,965**
29																	
30																	
31			**D** RR Tax Gross-up	1.705611462													
32																	
33		Grand Meadows			-	-	-	-	-	-	-	-	-	-	-	-	**-**
34		Nobles			2,868,727	2,466,822	2,910,502	3,393,562	2,515,110	1,967,858	1,562,004	1,184,309	2,190,460	2,645,821	3,203,117	2,570,868	**29,479,159**
35		Pleasant Valley			3,089,026	2,793,616	3,328,002	3,483,415	2,818,380	2,231,699	1,775,492	1,392,550	2,748,390	3,117,456	3,284,055	2,783,127	**32,845,208**
36		Border Winds			2,513,981	1,774,210	2,722,363	2,549,484	2,226,950	1,947,129	1,325,556	2,026,644	2,231,402	2,082,306	2,255,157	1,700,245	**25,355,428**
37	**PTC Revenue**	Courtenay		*Att. G, pg. 7-9*	3,233,156	2,576,930	3,287,753	3,425,004	2,845,924	2,515,414	1,937,505	2,024,103	2,778,541	3,255,750	3,030,425	3,009,795	**33,920,301**
38	**Requirements**	Blazing Star I		*Att. G, pg. 1-3*	-	-	-	-	-	-	-	-	-	-	-	3,001,718	**3,001,718**
39	**E = C x D**	Foxtail		*Att. G, pg. 16-18*	-	-	-	-	-	-	-	-	-	-	-	2,259,916	**2,259,916**
40		Crowned Ridge		*Att. G, pg. 10-12*	-	-	-	-	-	-	-	-	-	-	-	5,024,589	**5,024,589**
41		Lake Benton		*Att. G, pg. 22-24*	-	-	-	-	-	-	-	-	-	-	-	1,697,111	**1,697,111**
42		Blazing Star II		*Att. G, pg. 4-6*	-	-	-	-	-	-	-	-	-	-	-	-	**-**
43		Freeborn		*Att. G, pg. 19-21*	-	-	-	-	-	-	-	-	-	-	-	-	**-**
44		**Total PTC Value**			**11,704,890**	**9,611,578**	**12,248,620**	**12,851,465**	**10,406,364**	**8,662,101**	**6,600,557**	**6,627,606**	**9,948,794**	**11,101,332**	**11,772,754**	**22,047,370**	**133,583,430**
45																	
46																	
47			**F** '17 Energy Allocator	73.4132%													
48			**F** '18 Energy Allocator	73.1627%													
49			**F** '19 Energy Allocator	73.1290%													
50																	
51		Grand Meadows			-	-	-	-	-	-	-	-	-	-	-	-	**-**
52		Nobles			2,097,872	1,803,963	2,128,421	2,481,678	1,839,275	1,439,075	1,142,278	866,073	1,601,862	1,934,863	2,342,408	1,880,051	**21,557,821**
53		Pleasant Valley			2,258,975	2,042,944	2,433,735	2,547,387	2,061,054	1,632,020	1,298,400	1,018,358	2,009,871	2,279,765	2,401,597	2,035,274	**24,019,380**
54		Border Winds			1,838,449	1,297,462	1,990,837	1,864,413	1,628,547	1,423,917	969,366	1,482,065	1,631,803	1,522,770	1,649,174	1,243,373	**18,542,177**
55		**Sub Total Base Rate Wind Farms**			6,195,296	5,144,369	6,552,994	6,893,479	5,528,876	4,495,012	3,410,044	3,366,496	5,243,535	5,737,398	6,393,180	5,158,697	**64,119,377**
56	**MN Jur**	Courtenay			2,364,375	1,884,484	2,404,302	2,504,672	2,081,196	1,839,498	1,416,878	1,480,207	2,031,920	2,380,898	2,216,120	2,201,034	**24,805,584**
57	**PTC Value**	Blazing Star I			-	-	-	-	-	-	-	-	-	-	-	2,195,127	**2,195,127**
58	**G = E x F**	Foxtail			-	-	-	-	-	-	-	-	-	-	-	1,652,655	**1,652,655**
59		Crowned Ridge			-	-	-	-	-	-	-	-	-	-	-	3,674,433	**3,674,433**
60		Lake Benton			-	-	-	-	-	-	-	-	-	-	-	1,241,081	**1,241,081**
61		Blazing Star II			-	-	-	-	-	-	-	-	-	-	-	-	**-**
62		Freeborn			-	-	-	-	-	-	-	-	-	-	-	-	**-**
63		**Total MN Jur PTC Value**			**8,559,672**	**7,028,853**	**8,957,296**	**9,398,151**	**7,610,072**	**6,334,510**	**4,826,923**	**4,846,703**	**7,275,456**	**8,118,296**	**8,609,300**	**16,123,026**	**97,688,256**
64																	
65																	
66		Grand Meadows			-	-	-	-	-	-	-	-	-	-	-	-	**-**
67		Nobles			1,490,055	1,168,124	1,378,712	1,425,770	1,559,676	1,122,653	925,520	765,325	1,107,933	1,561,884	1,628,469	1,315,738	**15,449,859**
68	**H**	Pleasant Valley			1,943,017	1,256,973	1,450,104	1,507,926	1,510,847	1,108,577	1,003,122	713,828	1,145,009	1,613,657	1,622,305	1,329,262	**16,204,627**
69		Border Winds			1,134,360	975,614	995,647	1,286,597	1,179,509	866,249	726,685	595,516	845,342	1,179,187	1,257,295	938,722	**11,980,723**
70		**Total Base Rate Test Year PTC Forecast**			**4,567,432**	**3,400,711**	**3,824,463**	**4,220,293**	**4,250,032**	**3,097,479**	**2,655,327**	**2,074,669**	**3,098,284**	**4,354,728**	**4,508,069**	**3,583,722**	**43,635,209**
71																	
72	**Base Rate Test Year**		Test Year Allocators:														
73	**PTC Forecast from**		**I** '17 Energy Allocator	72.8410%													
74	**15-826**		**I** '18 Energy Allocator	72.5794%													
75			**I** '19 Energy Allocator	72.3290%													
76			**J** RR Tax Gross-up	1.705611462													
77																	
78		Grand Meadows			-	-	-	-	-	-	-	-	-	-	-	-	**-**
79		Nobles			1,838,210	1,441,059	1,700,852	1,758,905	1,924,098	1,384,964	1,141,770	944,145	1,366,804	1,926,822	2,008,965	1,623,164	**19,059,758**
80	**K = H x I x J**	Pleasant Valley			2,397,008	1,550,668	1,788,924	1,860,257	1,863,860	1,367,599	1,237,504	880,616	1,412,543	1,990,692	2,001,361	1,639,847	**19,990,879**
81		Border Winds			1,399,406	1,203,569	1,228,282	1,587,214	1,455,104	1,068,650	896,477	734,660	1,042,858	1,454,707	1,551,065	1,158,057	**14,780,049**
82		**Total MN Jur RR Base Rate Test Year PTC Forecast**			**5,634,624**	**4,195,296**	**4,718,059**	**5,206,375**	**5,243,063**	**3,821,213**	**3,275,751**	**2,559,421**	**3,822,206**	**5,372,221**	**5,561,391**	**4,421,068**	**53,830,687**
83																	
84																	
85	**PTC True-up**	Grand Meadows			-	-	-	-	-	-	-	-	-	-	-	-	**-**
86	**(Actual PTCs vs**	Nobles			(259,662)	(362,904)	(427,570)	(722,774)	84,823	(54,112)	(508)	78,072	(235,058)	(8,041)	(333,444)	(256,887)	**(2,498,063)**
87	**Base Rate Fcst)**	Pleasant Valley			138,033	(492,276)	(644,811)	(687,131)	(197,193)	(264,421)	(60,896)	(137,743)	(597,328)	(289,073)	(400,236)	(395,426)	**(4,028,500)**
88		Border Winds			(439,043)	(93,893)	(762,555)	(277,199)	(173,443)	(355,266)	(72,890)	(747,405)	(588,944)	(68,063)	(98,109)	(85,316)	**(3,762,127)**
89	**L = K - G**	**Total PTC True-up**			**(560,672)**	**(949,073)**	**(1,834,935)**	**(1,687,104)**	**(285,813)**	**(673,799)**	**(134,294)**	**(807,076)**	**(1,421,329)**	**(365,177)**	**(831,789)**	**(737,629)**	**(10,288,691)**

Att. E

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

REC Sales Summary for MN Jurisdiction

Line No. **[TRADE SECRET BEGINS**

Line No.	Counterparty	Transaction Execution Date (1)	REC Type	Vintages	Total Volume Sold A	Sell Price B	Total Proceeds C = A x B	MN % of Transaction (2) D	Proceeds to MN (3) E = C x D
1									
2									
3									
4									
5									
6									
7									
8									
9									

10 **TRADE SECRET ENDS]**

11

12 **Total** **$ 10,552,000**

13 *Att. C*

14 (1) Note, all transactions listed above occurred subsequent to the initial filing of Docket No. E002/M-15-805.

15 (2) The MN percent of the transaction is historically based on the energy allocator for MN, however the Company identified a past accounting issue in which MN was shorted their amount of allocated Poultry RECs. Therefore, the allocation was increased to 100%, and then to 85% in subsequent transactions to "pay back" the REC sales to MN.

16 (3) REC sale proceeds to be refunded to customers do not include any fees incurred by the Company.

ADIT Prorate Calculation

Line No.			Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total	
1	**Pro-Rate Days**	**A**	335	307	276	246	215	185	154	123	93	62	32	1		
2	**Pro-Rate Factor**	**B = A/365**	-	-	-	-	-	-	-	-	-	0.169863	0.087671	0.002740		
3																
4	**Deferred Tax Exp**	**C**	1,204,407	1,204,407	1,204,407	1,204,407	1,204,407	1,204,407	1,204,407	1,204,407	1,204,407	1,204,407	1,204,407	1,204,407	14,452,886	
5	**Prorated Deferred Tax Expense**	**D = B*C**	-	-	-	-	-	-	-	-	-	204,584	105,592	3,300	313,476	
6																
7	**Revenue Requirement Factor**	**E = WACC*(T/(1-T))**	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%		
8																
9	**RR of ADIT Pro-rate**	**F = D*E**	-	-	-	-	-	-	-	-	-	10,841	5,595	175	16,612	
10																
11	**Jurisdictional Allocator**	**G**	73.6194%	73.6194%	73.6194%	73.6194%	73.6194%	73.6194%	73.6194%	73.6194%	73.6194%	73.6194%	73.6194%	73.6194%		
12																
13	**MN Jur RR of ADIT Pro-rate**	**H = F*G**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**7,981**	**4,119**	**129**	**12,229**	*Att. C*
14																
15																
16																

Line No.			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	
17																
18																
19	**Pro-Rate Days**	**A**	335	307	276	246	215	185	154	123	93	62	32	1		
20	**Pro-Rate Factor**	**B = A/365**	0.917808	0.841096	0.756164	0.673973	0.589041	0.506849	0.421918	0.336986	0.254795	0.169863	0.087671	0.002740		
21																
22	**Deferred Tax Exp**	**C**	634,224	634,224	634,224	634,224	634,224	634,224	634,224	634,224	634,224	634,224	634,224	634,224	7,610,691	
23	**Prorated Deferred Tax Expense**	**D = B*C**	582,096	533,443	479,578	427,450	373,584	321,456	267,591	213,725	161,597	107,731	55,603	1,738	3,525,592	
24																
25	**Revenue Requirement Factor**	**E = WACC*(T/(1-T))**	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%		
26																
27	**RR of ADIT Pro-rate**	**F = D*E**	30,846	28,268	25,414	22,651	19,797	17,034	14,180	11,326	8,563	5,709	2,946	92	186,826	
28																
29	**Jurisdictional Allocator**	**G**	73.3062%	73.3062%	73.3062%	73.3062%	73.3062%	73.3062%	73.3062%	73.3062%	73.3062%	73.3062%	73.3062%	73.3062%		
30																
31	**MN Jur RR of ADIT Pro-rate**	**H = F*G**	**22,612**	**20,722**	**18,630**	**16,605**	**14,512**	**12,487**	**10,395**	**8,302**	**6,277**	**4,185**	**2,160**	**67**	**136,955**	*Att. D*
32																
33																
34																

Line No.			Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total	
35																
36																
37	**Pro-Rate Days**	**A**	335	307	276	246	215	185	154	123	93	62	32	1		
38	**Pro-Rate Factor**	**B = A/365**	0.917808	0.841096	0.756164	0.673973	0.589041	0.506849	0.421918	0.336986	0.254795	0.169863	0.087671	0.002740		
39																
40	**Deferred Tax Exp**	**C**	16,917,336	16,917,336	16,917,336	16,917,336	16,917,336	16,917,336	16,917,336	16,917,336	16,917,336	16,917,336	16,917,336	16,917,336	203,008,036	
41	**Prorated Deferred Tax Expense**	**D = B*C**	15,526,870	14,229,102	12,792,287	11,401,821	9,965,006	8,574,540	7,137,725	5,700,911	4,310,445	2,873,630	1,483,164	46,349	94,041,850	
42																
43	**Revenue Requirement Factor**	**E = WACC*(T/(1-T))**	5.29%	5.29%	5.29%	5.29%	5.29%	5.29%	5.29%	5.29%	5.29%	5.29%	5.29%	5.29%		
44																
45	**RR of ADIT Pro-rate**	**F = D*E**	821,695	753,016	676,979	603,394	527,357	453,772	377,735	301,697	228,112	152,075	78,490	2,453	4,976,776	
46																
47	**Jurisdictional Allocator**	**G**	73.1342%	73.1342%	73.1342%	73.1342%	73.1342%	73.1342%	73.1342%	73.1342%	73.1342%	73.1342%	73.1342%	73.1342%		
48																
49	**MN Jur RR of ADIT Pro-rate**	**H = F*G**	**600,940**	**550,712**	**495,103**	**441,287**	**385,678**	**331,862**	**276,253**	**220,644**	**166,828**	**111,219**	**57,403**	**1,794**	**3,639,723**	*Att. E*

Minnesota Calendar Month Electric Sales (MWh)

Line No.		Residential w/o Sp Heat	Residential w/ Sp Heat	Total Residential	Small C&I	Large C&I	Total C&I	Street Lighting	Public Authority	Interdept	Total Other	Total Retail
1	**Oct-17**	585,413	24,802	610,215	1,076,533	713,852	1,790,385	10,485	6,070	797	17,351	2,417,950
2	**Nov-17**	615,815	36,255	652,070	991,918	657,691	1,649,609	10,747	4,609	203	15,560	2,317,239
3	**Dec-17**	726,666	50,157	776,823	1,108,769	640,176	1,748,945	12,764	4,516	1,290	18,570	2,544,338
4	**Total 17**	1,927,894	111,213	2,039,108	3,177,220	2,011,719	5,188,939	33,996	15,195	2,290	51,481	7,279,528
5												
6	**Jan-18**	760,497	58,738	819,235	1,138,335	618,726	1,757,061	12,896	5,164	418	18,478	2,594,774
7	**Feb-18**	614,858	47,492	662,350	975,672	607,703	1,583,375	10,971	4,103	267	15,340	2,261,066
8	**Mar-18**	612,513	41,194	653,707	1,106,523	648,556	1,755,079	10,672	5,042	832	16,546	2,425,332
9	**Apr-18**	512,921	22,780	535,701	933,348	646,343	1,579,691	8,982	4,409	558	13,948	2,129,341
10	**May-18**	575,441	20,199	595,640	1,072,126	672,120	1,744,245	7,916	4,984	207	13,108	2,352,993
11	**Jun-18**	745,211	20,867	766,078	1,148,434	671,786	1,820,220	7,279	5,402	2,430	15,110	2,601,408
12	**Jul-18**	922,786	24,669	947,455	1,284,333	749,148	2,033,481	7,237	6,534	850	14,620	2,995,556
13	**Aug-18**	865,347	23,680	889,026	1,244,998	754,808	1,999,807	6,724	8,140	458	15,322	2,904,155
14	**Sep-18**	657,356	19,550	676,906	1,113,919	693,424	1,807,344	8,201	6,427	1,040	15,668	2,499,917
15	**Oct-18**	582,372	24,705	607,077	1,080,012	675,500	1,755,512	9,179	6,364	797	16,339	2,378,928
16	**Nov-18**	612,991	36,286	649,277	995,484	621,464	1,616,948	9,716	4,623	203	14,542	2,280,766
17	**Dec-18**	726,262	50,514	776,776	1,112,613	604,967	1,717,581	11,390	4,529	1,290	17,210	2,511,567
18	**Total 18**	8,188,556	390,672	8,579,229	13,205,799	7,964,545	21,170,344	111,162	65,720	9,349	186,231	29,935,803
19												
20												

21 **Minnesota Calendar Month Base Revenues ($000s)**

22

Line No.		Residential w/o Sp Heat	Residential w/ Sp Heat	Total Residential	Small C&I	Large C&I	Total C&I	Street Lighting	Public Authority	Interdept	Total Other	Total Retail	
23–24		Residential w/o Sp Heat	Residential w/ Sp Heat	Total Residential	Small C&I	Large C&I	Total C&I	Street Lighting	Public Authority	Interdept	Total Other	Total Retail	
25	**Jan-18**	78,259	3,837	82,096	72,191	28,945	101,136	1,763	434	26	2,222	185,455	
26	**Feb-18**	65,122	3,170	68,292	63,404	28,382	91,786	1,500	358	17	1,875	161,953	*Att. A (refund)*
27	**Mar-18**	64,923	2,799	67,723	72,847	30,653	103,500	1,459	439	51	1,949	173,171	
28	**Apr-18**	55,955	1,708	57,663	63,038	31,116	94,154	1,228	401	35	1,663	153,481	
29	**May-18**	61,611	1,559	63,170	73,251	32,607	105,858	1,082	451	13	1,546	170,574	
30	**Jun-18**	81,963	2,392	84,355	90,570	37,521	128,091	1,467	578	150	2,196	214,642	
31	**Jul-18**	99,190	2,760	101,951	99,491	41,542	141,033	1,459	664	53	2,175	245,159	
32	**Aug-18**	93,651	2,664	96,315	97,341	42,053	139,393	1,356	782	28	2,166	237,874	
33	**Sep-18**	73,465	2,267	75,732	88,081	39,201	127,282	1,653	634	64	2,352	205,366	
34	**Oct-18**	62,275	1,836	64,112	73,968	33,241	107,210	1,255	547	49	1,851	173,172	
35	**Nov-18**	65,040	2,523	67,563	66,599	30,277	96,876	1,328	416	13	1,756	166,196	
36	**Dec-18**	75,250	3,357	78,607	71,038	29,043	100,080	1,557	391	80	2,028	180,716	
37	**Total 18**	876,704	30,875	907,579	931,817	404,582	1,336,399	17,106	6,094	579	23,779	2,267,757	
38													
39												Mar-Dec Total:	
40												1,920,350	*Att. A (new rate)*

Universal Inputs

Line No.			2017	2018	2019
	Capital Structure				
1		Long Term Debt %	46.04%	46.41%	45.81%
2		Long Term Debt Cost	4.81%	4.77%	4.75%
3		Short Term Debt %	1.46%	1.09%	1.69%
4		Short Term Debt Cost	3.57%	4.45%	4.31%
5		Weighted Cost of Debt	2.26%	2.26%	2.25%
6					
7		Common Stock %	52.50%	52.50%	52.50%
8		Common Stock Cost	10.00%	10.00%	10.00%
9		Weighted Cost of Equity	5.25%	5.25%	5.25%
10		Rate of Return	7.51%	7.51%	7.50%
11					
12	**Tax Rates**				
13	Income Tax Rates				
14		State Income Tax Rate	9.80%	9.80%	9.80%
15		Federal Income Tax Rate	35.00%	35.00%	35.00%
16					
17	Composite Income Tax Rate				
18		State Composite Income Tax Rate	41.37%	41.37%	41.37%
19		Company Composite Income Tax Rate	40.8468%	40.8468%	40.8468%
20					
21	Property Tax Rate (Transmission)		1.664%	1.664%	1.664%
22					
23	**Allocators**				
24	MN 12-month CP energy (Electric Energy)		87.3858%	87.1864%	87.1291%
25	NSPM 36-month CP demand (Interchange Electric)		84.2464%	84.0798%	83.9377%
26	Wind	Jurisdictional Allocator	73.6194%	73.3062%	73.1342%
27					
28	MN 12-month CP demand (Electric Demand)		87.3462%	87.3171%	87.2773%
29	NSPM 36-month CP demand (Interchange Electric)		84.2464%	84.0798%	83.9377%
30	Trans	Jurisdictional Allocator	73.5860%	73.4160%	73.2586%
31					
32	MN 12-month CP energy (Electric Energy)		87.3858%	87.1864%	87.1291%
33	NSPM Interchange Energy (Interchange Electric)		84.0104%	83.9153%	83.9318%
34	PTC	Jurisdictional Allocator	73.4132%	73.1627%	73.1290%

Redline

DETERMINATION OF RES ADJUSTMENT FACTOR

The Renewable Energy Standard ("RES") Adjustment Factor shall be the RES annual forecasted revenue requirement as a percentage of "base" revenues. The RES annual forecasted revenue requirement shall be the sum of the Renewable Energy Standard Costs for the forecast period and any residual Tracker balance in the RES Tracker Account.

The RES Adjustment Factor may be adjusted with the approval of the Minnesota Public Utilities Commission (Commission). The RES Factor is:

All Classes	~~0.497%~~negative 6.384%	R

RENEWABLE ENERGY STANDARD COSTS

The RES Costs shall be the annual revenue requirements including operation and maintenance (O&M) expenses for Company owned Renewable Energy Project costs and capacity related renewable energy purchased power costs not recoverable through the FCR, that are eligible for recovery under Minnesota Statute Section 216B.1645. A standard model will be used to calculate the total forecasted revenue requirements for each annual period that is determined by the Commission to be eligible for recovery under this Renewable Energy Standard Rider.

RES TRACKER ACCOUNT

For each annual true-up period, a true-up adjustment to the RES Tracker Account (residual Tracker balance) will be calculated reflecting the difference between the RES Adjustment recoveries and the actual expenditures for such period. The true-up adjustment shall be included in calculating the RES Adjustment Factor effective with the start of the next annual recovery period.

The RES Adjustment Factor includes a true-up of actuals as available for the previous recovery period and forecast information for the remainder of the recovery period. The Final true-up adjustment for a previous recovery period will be determined by September 1 of the following year, at which time the Company will record a Final adjustment to the RES Tracker Account.

All costs appropriately charged to the RES Tracker Account shall be eligible for recovery through this rider.

PROVISION OF FORECAST DATA

To assist commercial and industrial customers in budgeting and managing their energy costs, the Company will annually make available on September 1st a 24-month forecast of the RES Adjustment Factor applicable to demand billed C&I customers under this Rider. The forecast period begins January 1st of the following year. This forecast will be provided only to customers who have signed a protective agreement with the Company.

Clean

DETERMINATION OF RES ADJUSTMENT FACTOR

The Renewable Energy Standard ("RES") Adjustment Factor shall be the RES annual forecasted revenue requirement as a percentage of "base" revenues. The RES annual forecasted revenue requirement shall be the sum of the Renewable Energy Standard Costs for the forecast period and any residual Tracker balance in the RES Tracker Account.

The RES Adjustment Factor may be adjusted with the approval of the Minnesota Public Utilities Commission (Commission). The RES Factor is:

All Classes	negative 6.384%	R

RENEWABLE ENERGY STANDARD COSTS

The RES Costs shall be the annual revenue requirements including operation and maintenance (O&M) expenses for Company owned Renewable Energy Project costs and capacity related renewable energy purchased power costs not recoverable through the FCR, that are eligible for recovery under Minnesota Statute Section 216B.1645. A standard model will be used to calculate the total forecasted revenue requirements for each annual period that is determined by the Commission to be eligible for recovery under this Renewable Energy Standard Rider.

RES TRACKER ACCOUNT

For each annual true-up period, a true-up adjustment to the RES Tracker Account (residual Tracker balance) will be calculated reflecting the difference between the RES Adjustment recoveries and the actual expenditures for such period. The true-up adjustment shall be included in calculating the RES Adjustment Factor effective with the start of the next annual recovery period.

The RES Adjustment Factor includes a true-up of actuals as available for the previous recovery period and forecast information for the remainder of the recovery period. The Final true-up adjustment for a previous recovery period will be determined by September 1 of the following year, at which time the Company will record a Final adjustment to the RES Tracker Account.

All costs appropriately charged to the RES Tracker Account shall be eligible for recovery through this rider.

PROVISION OF FORECAST DATA

To assist commercial and industrial customers in budgeting and managing their energy costs, the Company will annually make available on September 1st a 24-month forecast of the RES Adjustment Factor applicable to demand billed C&I customers under this Rider. The forecast period begins January 1st of the following year. This forecast will be provided only to customers who have signed a protective agreement with the Company.

Redline

DETERMINATION OF RES ADJUSTMENT FACTOR

The Renewable Energy Standard ("RES") Adjustment Factor shall be the RES annual forecasted revenue requirement as a percentage of "base" revenues. The RES annual forecasted revenue requirement shall be the sum of the Renewable Energy Standard Costs for the forecast period and any residual Tracker balance in the RES Tracker Account.

The RES Adjustment Factor may be adjusted with the approval of the Minnesota Public Utilities Commission (Commission). The RES Factor is:

All Classes	~~negative 6.384%~~0.497%	R

RENEWABLE ENERGY STANDARD COSTS

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Attachment O

This attachment is NOT PUBLIC in its entirety.

Attachment P

This attachment is NOT PUBLIC in its entirety.

REPORT:

COST OF EQUITY – RES RIDER

PREPARED FOR

NORTHERN STATES POWER COMPANY - MINNESOTA

BEFORE THE:

MINNESOTA PUBLIC UTILITIES COMMISSION

NOVEMBER 17, 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 Renewable Energy Services ("RES") 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 7.2.

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") for an electric utility proxy group. In addition, I consider the CAPM results for a merchant generation proxy group, authorized returns in other jurisdictions for electric utility companies in 2016 and 2017, the incremental risk associated with renewable energy projects and the Commission's prior precedents for setting RES 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 for the electric utility proxy group from 8.19 percent to 10.78 percent based on a combination of models and alternative input assumptions. For the merchant generation proxy group, the CAPM analysis indicates that return requirements are approximately 14.75 percent. Based on the results of all three methods (i.e., DCF, Risk Premium, and CAPM) for the electric proxy group, and taking

[1] I use the terms "ROE" and "cost of equity" interchangeably throughout my Direct Testimony.

into consideration my observations pertaining to capital market conditions, authorized returns in other jurisdictions, and the return requirements for merchant generators, I derive a range of results from 10.0 percent to 11.0 percent. Although my analyses support an ROE recommendation toward the upper end of this range, NSPM has elected to request an ROE of 10.0 percent for the RES rider, which is a conservative estimate of the cost of equity for these types of renewable investments.

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 electric utility companies. Section VI discusses the market data and models used to estimate the cost of equity for the electric proxy group, as well as the results of the Constant Growth DCF, Risk Premium and CAPM analyses. Section VII discusses the incremental risk associated with investments in generation assets, and presents the results of a CAPM analysis for a proxy group of merchant generation companies. Section VIII 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.[2] 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.

Pursuant to Minnesota statute, NSPM is allowed to earn a return on its investment in renewable energy facilities and resources.[3] As one point of reference, 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.[4] In its decision approving the settlement, the Commission stated "the

[2] Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944), at 602.
[3] Minn. Statute 216B.1645, subd.2a.
[4] E-002/GR-15-0826, May 11, 2017.

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."[5] In support of my recommendation, I present an updated cost of equity analysis for the electric utility proxy group, as well as an additional analysis specific to unregulated generation assets and a review of authorized returns in other jurisdictions.

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

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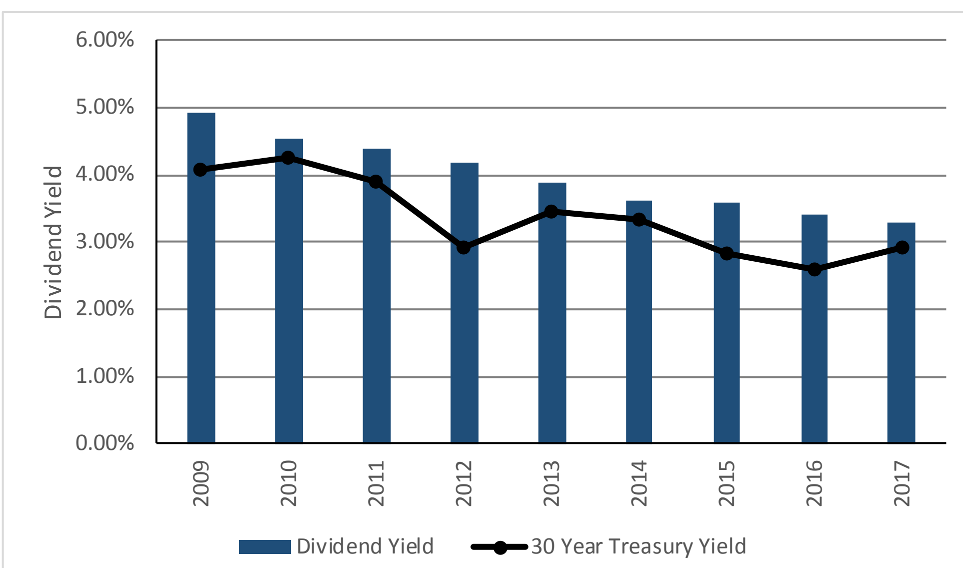
5 *Ibid,* at 22.

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 1.37 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.

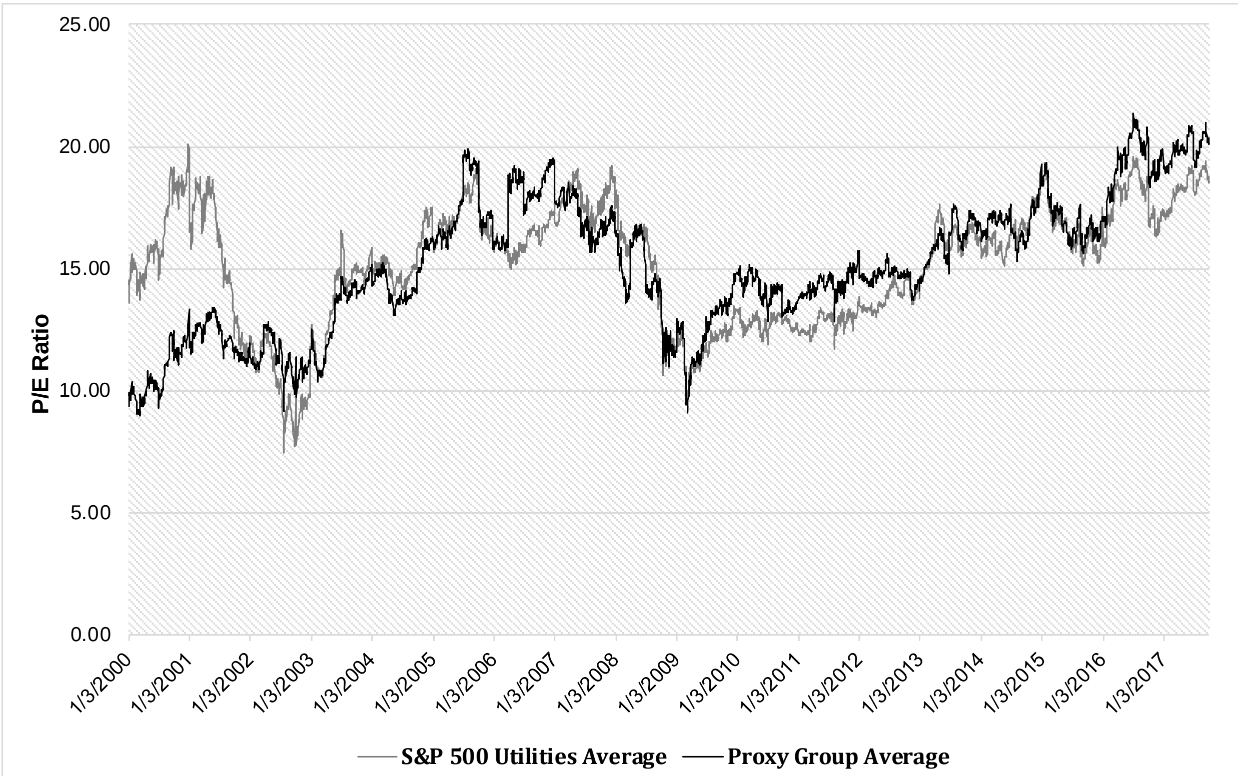
The DCF model is generally a reliable model to estimate the cost of equity and adequately reflects market conditions and investor expectations. However, in the current market environment, the DCF model results are distorted by the historically low level of interest rates and the higher valuation of utility 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.[6]

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.

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

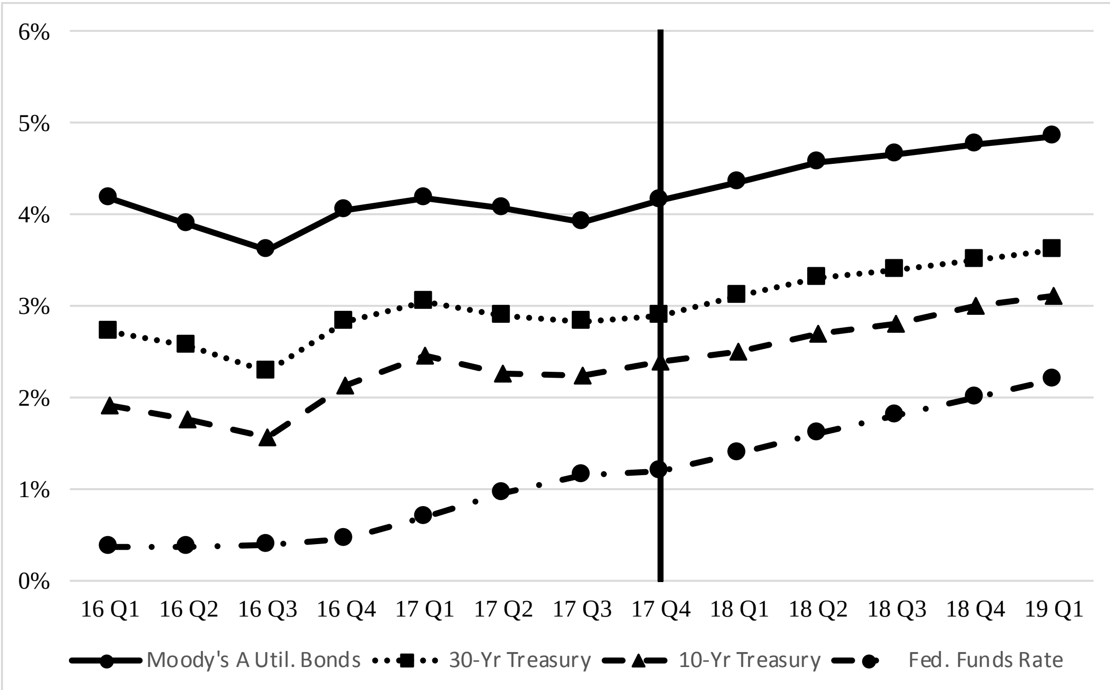
Figure 2: Utility P/E Ratios vs. Proxy Group 2000 to September 2017



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.[7]

[7] 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.

Figure 3: Interest Rate Conditions[8]



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.[9]

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.[10] 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 100 basis points.[11] 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

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8 Source: Historical data from Bloomberg Professional. Forecast data from Blue Chip Financial Forecasts, Volume 36, No. 10, October 1, 2017, at 2.
9 FOMC, Federal Reserve press release, December 14, 2016.
10 Blue Chip Financial Forecasts, Vol. 36, Issue No. 10, October 1, 2017, at 14.
11 *Ibid.*

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.[12] 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. 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 September 2016, which supports an ROE for the RES 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 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

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

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.[13] 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 regulated gas distribution business.[14] NSPM's long-term issuer ratings are A- from Standard & Poor's ("S&P") and A2 from Moody's Investor Services ("Moody's").[15]

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;

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[13] Northern States Power – Minnesota FERC Form 1, December 31, 2016, at 304; Gas Jurisdictional Annual Report, Northern States Power – Minnesota, 2016.
[14] Northern States Power – Minnesota FERC Form 1, December 31, 2016, at 115.
[15] Source: SNL Financial.

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.

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 electric utility 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. <u>Constant Growth DCF Model</u>

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…[16]
>
> ****
>
> 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.[17]
>
> ****
>
> 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

[16] 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.

[17] *Ibid.*, at para 122.

> necessary and reasonable to consider additional record evidence, including evidence of alternative methodologies…[18]

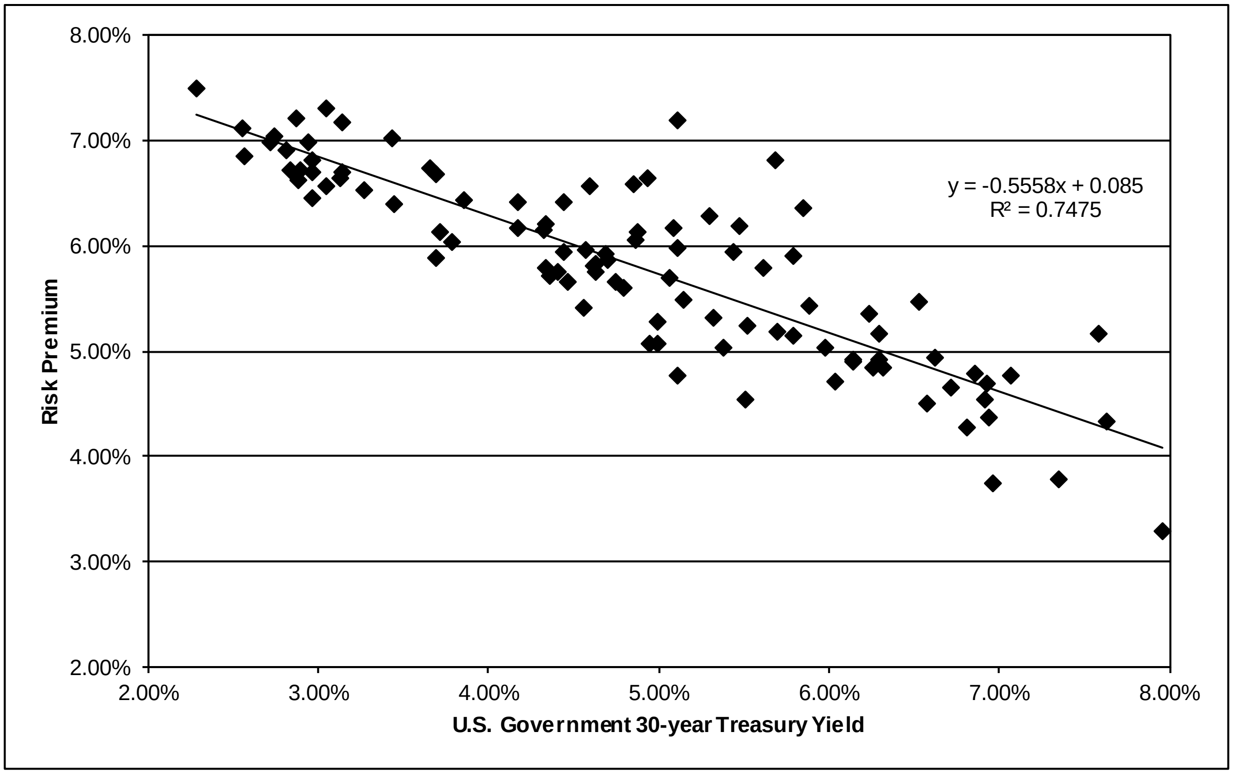
Following the FERC's logic in Opinion No. 551, yields on 10-year Treasury bonds remain well below 3.0 percent,[19] which is the level that the FERC determined represents "anomalous" capital market conditions. The results of the DCF model are understating the cost of equity under current market conditions 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.*
[19] 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[20]	Using Long-Term Forecast for Yield 30-Year Treasury Bond[21]
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 Figure 8. 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.

20 Blue Chip consensus forecast for 4Q 2017 – 1Q 2019, as of October 1, 2017.
21 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. CAPM Analysis

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.[22] 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

22 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.[23]

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. Flotation Costs

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

[23] 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).

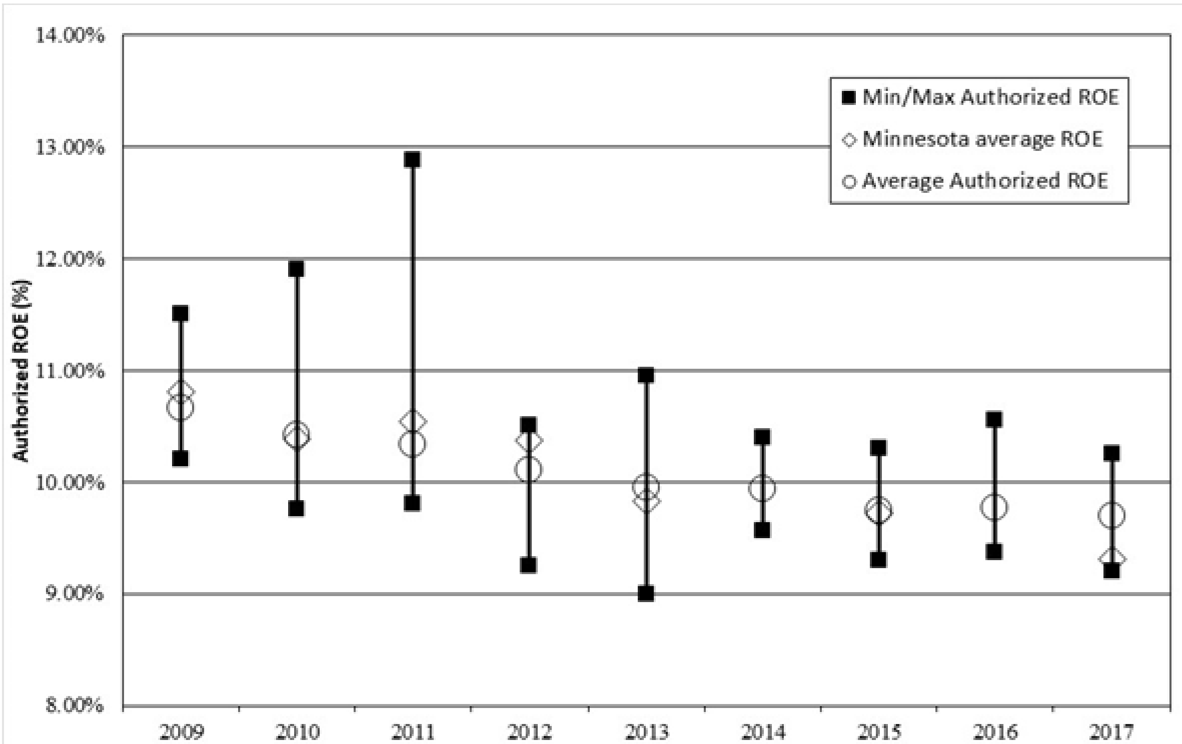
The need to reimburse investors for equity issuance costs has been recognized by the Commission in many, although not all, previous decisions.[24] I did not make an explicit adjustment for flotation costs. Rather, I took into consideration flotation costs in establishing my recommended ROE, which reflects the range of results from my Constant Growth DCF, CAPM, and Risk Premium analyses.

E. Authorized Returns in Other Jurisdictions

In addition to the results of the traditional ROE estimation models, 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.

[24] 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.

Figure 10: Comparison of Minnesota and U.S. Authorized Returns[25]



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.

---

25 Source: SNL Financial.

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 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 RES 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. GENERATION RISK AND ROE

In order to recognize the specific risks associated with electric generation investments, I also developed a proxy group of merchant generation companies in order to evaluate the return requirements for those types of investments. In general, generation risks may be broken down into the following six categories: 1) development and construction risk; 2) market and fuel risk; 3) counterparty risk; 4) operating risk; 5) regulatory risk; and 6) technological risk. Company 10-K filings with the U.S. Securities and Exchange Commission document the risks associated with their businesses for investors, including risk associated with electric generation investments.

The majority of NSPM's renewable energy investments are related to the development of wind generation projects. While the wind generation business has matured, wind projects are generally considered to be riskier investments than conventional technology.

FERC also acknowledged the unique characteristics of wind generation:

> Even with the advances in wind development, wind generation is a relatively new entrant to markets that were not designed specifically for intermittent energy resources or for generation sited remotely from load centers. As such, wind generation faces several challenges to achieve widespread acceptance, including siting and permitting issues, financing issues, and transmission policies that are currently designed for generating units that are more centrally located and able to be dispatched.[26]

[26] "Assessing the State of Wind Energy in Wholesale Electricity Markets," Federal Energy Regulatory Commission, Docket No. AD04-13-000, Staff Briefing Paper, November 2004, at 16.

I evaluate the return requirements associated with generation investment by calculating the ROE for a proxy group of unregulated generating companies. This is the most accurate measure of the market's expected returns for equity investments in the generation business segment of the power industry. This segment captures the common equity returns required for taking the risk of developing and owning generation in general, but does not take into account wind specific risk or the regulatory protection afforded to NSPM's investments. I then consider the portion of this incremental equity return appropriate for investing in regulated generation, and in particular wind projects.

In order to estimate the ROE for investment in generation facilities, I have conducted a CAPM analysis of six companies that own a significant portfolio of non-rate-regulated generating assets. This "Generation Proxy Group" consists of the companies shown in Figure 11.

Figure 11: Generation Proxy Group

Company	Ticker
The AES Corporation	AES
Calpine Corporation	CPN
Covanta Holding Corp.	CVA
Dynegy, Inc.	DYN
NRG Energy, Inc.	NRG
TransAlta Corporation	TA.TO

Defining this Generation Proxy Group allows me to calculate a Beta specific to building and owning generation facilities. The risk-free rate and market risk premium calculations are the same as those used in my CAPM calculation for the electric proxy group. The results of my CAPM analysis for the Generation Proxy Group are provided in Schedule 7.2 and summarized in Figure 12.

Figure 12: Forward-Looking CAPM Results – Generation Proxy Group

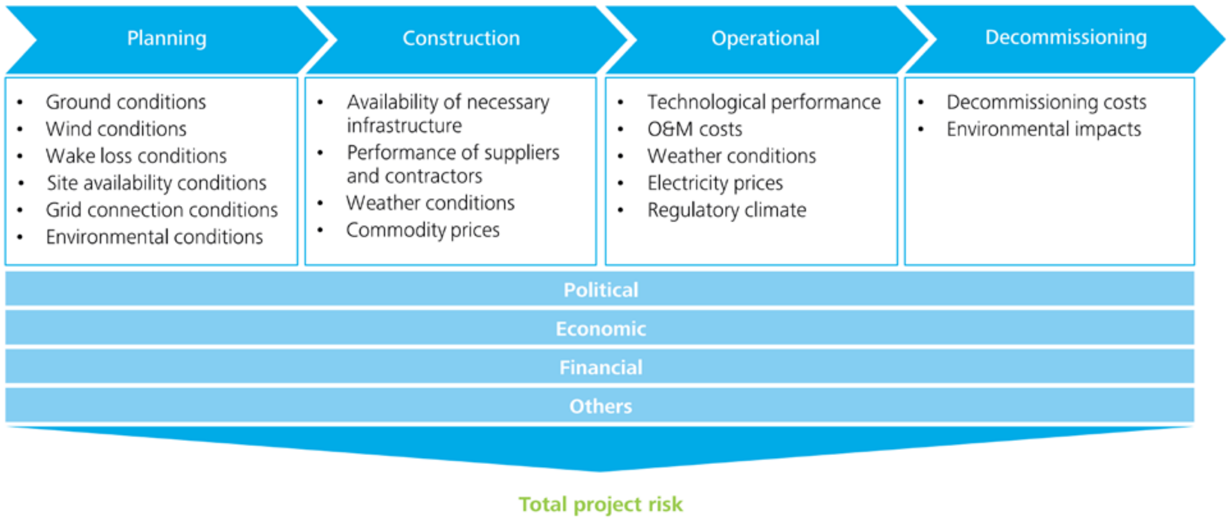
Using Value Line Betas	14.86%
Using Bloomberg Betas	14.57%
Mean Result	14.72%

The forward-looking CAPM results for the Generation Proxy Group are more than 450 basis points higher than the forward-looking CAPM results for the electric proxy group. NSPM is exposed to some, but not all of the risks these companies are exposed to with their generation investments. Recognizing that NSPM's renewable energy investments recovered through the RES rider are not subject to the same degree of risk typically associated with an unregulated generation company, I have reduced the generator return differential accordingly. In the Low ROE case, the return differential is reduced by 90 percent, suggesting that 90 percent of the risk borne by an unregulated generation company would be mitigated by NSPM's RES rider treatment. In the High ROE case, I assume that 70 percent of this risk is mitigated. Under these two scenarios, an ROE between 45 and 135 basis points[27] above the mean results for the electric proxy group is required to compensate investors for the additional risks associated with generation in general and wind generation in particular.

The determination of the remaining 10 – 30 percent risk differential is subjective, but supported by a risk profile that differs from other utility investments. Generation projects in general, and wind specifically, are subject to greater planning, construction, operating and decommissioning risks than routine poles and wires investments. These risks for wind projects include:[28]

[27] Derived by multiplying 450 basis points by (1-.90) in the Low ROE case and (1-.30) in the High ROE case to arrive at an ROE differential of 45 to 135 basis points.
[28] Establishing the Investment Case: Wind Power, Deloitte, April 2014, at 18.

Overview of general and stage-specific risks



These risks are partially, but not entirely, mitigated by NSPM's regulatory compact. The unique wind risk elements in relation to power generation risks are described more fully in Schedule 6, where I also consider the NSPM specific risks associated with its wind-related investments.

As a further point of comparison, the Code of Virginia Section 56-585.1 (sub. 6) allows electric utilities to earn an additional 200 basis points above the base ROE for investments in renewable powered generation projects for the first 10 to 20 years of service life for the asset. My estimated premium for wind generation is somewhat lower than the ROE adder for renewable generation investments of 200 basis points that is allowed by Virginia statute.

VIII. SUMMARY AND CONCLUSIONS

Figure 13 summarizes the mean results of my DCF, Risk Premium and CAPM analyses for the electric utility proxy group.

Figure 13: 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 electric 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 CAPM results for the Generation Proxy Group of 14.72 percent. My ROE recommendation for the RES 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 forward-looking CAPM analysis for the Generation Proxy Group produces a mean result of 14.72 percent. Taking into consideration the risk-mitigating effects of generation owned by NSPM as compared to unregulated generation, a risk premium of 45 to 135 basis points above the average for the electric utility proxy group is warranted; 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.

Based on the results of all three methods (i.e., DCF, Risk Premium, and CAPM) for the electric proxy group, and taking into consideration my observations pertaining to capital market conditions, authorized returns in other jurisdictions, and the return requirements for merchant generators, I derive a range of results from 10.0 percent to 11.0 percent. Although my analyses support an ROE recommendation toward the upper end of this range, NSPM has elected to request an ROE of 10.0 percent for the RES rider, which is a conservative estimate of the cost of equity for these types of renewable investments.

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

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:

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

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:

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

<u>CAPM Analysis</u>

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

		[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	$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

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	$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

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	$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%

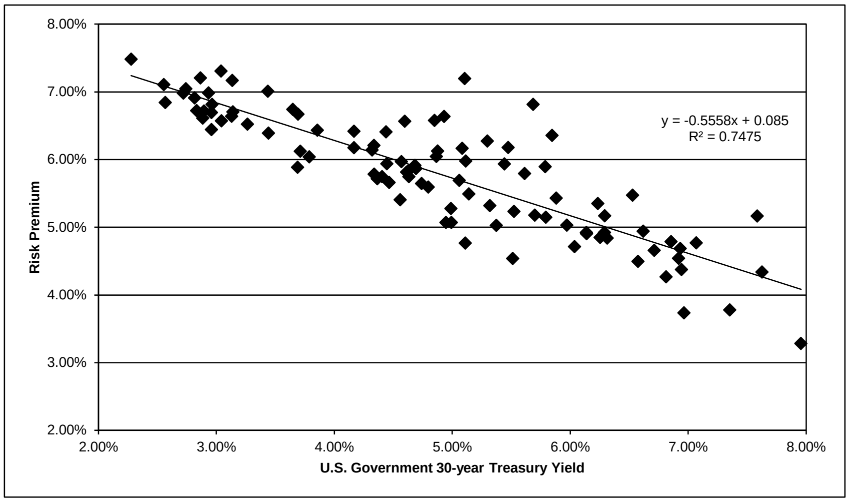
Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of September 29, 2017
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x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

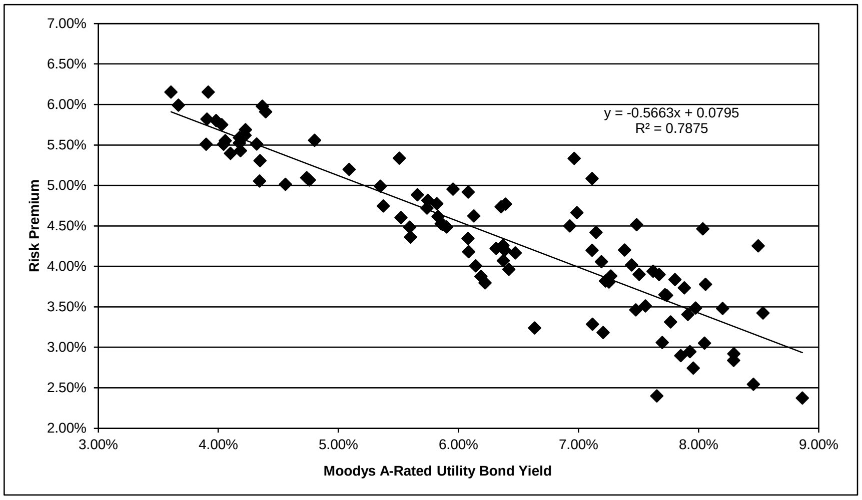
Notes:
[1] Source: Regulatory Research Associates, accessed October 5, 2017
[2] Source: Bloomberg Professional, quarterly bond yields are an average of the trading days in each quarter
[3] Equals Column [1] − Column [2]
[4] Source: Bloomberg Professional, equals 30-day average as of September 29, 2017
[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] Bloomberg	[2] 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

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[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

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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%

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STANDARD AND POOR'S 500 INDEX

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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

[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
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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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%

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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
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%

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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

[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
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]

GENERATION RISK SUMMARY

Risk Type	Electric Generation	Wind Specific	NSPM Wind Projects
Development & Construction	Risks associated with the costs and successful completion of permitting and construction of the facility	Securing land options and leases, validating wind potential, securing state, local and federal permits, site layout and engineering, negotiations with turbine manufacturers and balance of plant construction. The majority of proposed wind projects that start down this path do not reach commercial fruition.	The self-build projects start with the negotiation and execution of a purchase agreement to acquire a site from the developer. Once the site is purchased, NSPM must negotiate contracts to procure turbines and construct the facility. Additionally, NSPM bears interconnection risks including uncertainty around GIA/network upgrade costs. For build-transfer projects, NSPM negotiates and executes a purchase agreement to acquire a fully constructed and operating facility.
Markets & Fuels	Uncertainty associated with future electric prices, fuel price and availability	Fuel risk is not a direct factor, but the values of future electric energy, capacity and resource credits are ongoing uncertainties.	NSPM wind projects face MISO market risks including curtailment and the value of capacity resource credits.
Counterparty	Performance by the contractor building the plant, parties purchasing the output and providing fuel supply	The major counterparties are the land owners, turbine manufacturer, balance of plant constructor, electric power offtake party and transmission provider.	Major counterparties for the self-build projects include the project developer to deliver a shovel-ready site, turbine supplier and balance of plant contractor. For build-transfer projects, the major counterparty is the project developer.
Operating	Failure of the facility to deliver projected output levels, mechanical failures and unforeseen maintenance expenditures	Turbine technology has made significant strides over prior generations and the companies manufacturing these products are larger and more sophisticated, but the long term performance of these facilities must pass the test of time. Weather also factors into the equation for wind projects, both in terms of the actual versus predicted wind resource and the impacts of storms or ice on operating units.	NSPM wind projects face operating risks associated with unexpected maintenance expenditure and less than expected output levels driven in part by weather, curtailment and outages.
Regulatory	Regulatory risk can arise from changes in either state or federal policies that impact the ability of utilities to recover their investments or operating costs as market circumstances change over time. Given the ongoing restructuring of U.S. wholesale power markets, volatile fuel prices, and greater emphasis on utility air emissions, these risks are greater for generating related investments.	Wind projects are most susceptible to changes in tax rules, renewable resource credit markets, regulatory cost recovery, and changes in electric power market rules.	NSPM may be allowed to recover capital costs associated with renewable energy investments through the RES rider while the project is under construction. Once the project is placed in service, the investment may be moved to base rates in the next rate case filing. There is uncertainty regarding tax credits for wind projects under the new tax legislation being introduced in Congress. There is also uncertainty in the final cost of constructing the self-build projects with a risk that costs could exceed the Commission approved cap.
Technology	Technological risk arises when the value of existing technologies is diminished by new products. Generating technology has evolved faster than the core technologies utilized in the other major segments of the utility business, and should be expected to do so into the future.	Given the evolving wind industry, the technological risk for wind projects is higher than for more mature generating technologies.	NSPM wind projects are not immune to the rapidly changing turbine technology.

BETA - MERCHANT GENERATION PROXY GROUP
AS OF SEPTEMBER 29, 2017

		[1] Bloomberg	[2] Value Line
AES Corporation	AES	0.931	1.200
Calpine Corporation	CPN	1.038	1.100
Covanta Holding Corporation	CVA	1.120	0.950
Dynegy Inc.	DYN	1.407	1.400
NRG Energy, Inc.	NRG	1.037	1.300
TransAlta Corporation	TA.TO	1.127	0.900
Average		1.110	1.142

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

CAPITAL ASSET PRICING MODEL - MERCHANT GENERATION PROXY GROUP

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

	[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%	1.110	13.55%	10.78%	14.74%
Near-term projected 30-year U.S. Treasury bond yield (Q4 2017 - Q1 2019) [2]	3.30%	1.110	13.55%	10.25%	14.68%
Projected 30-year U.S. Treasury bond yield (2019 - 2023) [3]	4.30%	1.110	13.55%	9.25%	14.57%
				Average:	**14.66%**
				Median:	**14.68%**
Proxy Group Average Value Line Beta					
Current 30-day average of 30-year U.S. Treasury bond yield [1]	2.77%	1.142	13.55%	10.78%	15.08%
Near-term projected 30-year U.S. Treasury bond yield (Q4 2017 - Q1 2019) [2]	3.30%	1.142	13.55%	10.25%	15.00%
Projected 30-year U.S. Treasury bond yield (2019 - 2023) [3]	4.30%	1.142	13.55%	9.25%	14.86%
				Average:	**14.98%**
				Median:	**15.00%**

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: Source: Schedule 4.2
[7] Equals [6] − [4]
[8] Equals [4] + [5] x [7]

CERTIFICATE OF SERVICE

I, Carl Cronin, 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

DOCKET NO. E002/M-17-___
XCEL ENERGY'S MISCELLANEOUS ELECTRIC SERVICE LIST

Dated this 17th day of November 2017

/s/
____
Carl Cronin

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Aafedt	daafedt@winthrop.com	Winthrop & Weinstine, P.A.	Suite 3500, 225 South Sixth Street Minneapolis, MN 554024629	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Ryan	Barlow	Ryan.Barlow@ag.state.mn.us	Office of the Attorney General-RUD	445 Minnesota Street Bremer Tower, Suite 1400 St. Paul, Minnesota 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
James J.	Bertrand	james.bertrand@stinson.com	Stinson Leonard Street LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
William A.	Blazar	bblazar@mnchamber.com	Minnesota Chamber Of Commerce	Suite 1500 400 Robert Street North St. Paul, MN 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
James	Canaday	james.canaday@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota St. St. Paul, MN 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Jeanne	Cochran	Jeanne.Cochran@state.mn.us	Office of Administrative Hearings	P.O. Box 64620 St. Paul, MN 55164-0620	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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