414 Nicollet Mall
Minneapolis, MN 55401

May 14, 2018

—Via Electronic Filing—

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

RE: REPLY COMMENTS
TRANSMISSION COST RECOVERY RIDER
DOCKET NO. E002/M-17-797

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Reply Comments in response to the April 2, 2018 Comments of the Department of Commerce, Division of Energy Resources and the Office of the Attorney General – Residential Utilities and Antitrust Division in the above-referenced docket.

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

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

Sincerely,

/s/

HOLLY HINMAN
REGULATORY MANAGER

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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

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

DOCKET NO. E002/M-17-797

REPLY COMMENTS

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits this Reply to the Comments submitted by the Minnesota Department of Commerce, Division of Energy Resources and the Office of the Attorney General – Residential Utilities and Antitrust Division on April 2, 2018 regarding our Petition for approval of the Transmission Cost Recovery (TCR) Rider combined revenue requirements for 2017 and 2018 and the corresponding TCR adjustment factors.

REPLY

Our Reply provides the following additional information in support of our Petition as requested by the Department:

- Advanced Distribution Management System (ADMS) CWIP Balances and Allocation;
- Regional Expansion Criteria and Benefits (RECB) Forecast, Related Interest, and December 2016 True-Up; and
- Impact of the Tax Cuts and Jobs Act.

In addition, we respond to several additional recommendations related to the following topics:

- Return on Equity (ROE);
- Accumulated Deferred Income Tax (ADIT) Proration; and
- Proposed Carrying Charge.

A. ADMS CWIP Balances

The Department asked that we confirm that the CWIP balances shown in Attachment 13 for the ADMS project do not include hardware costs, and also explain what is included in those CWIP balances and why they differ from the budgeted costs. There are two primary reasons for the deviation between the CWIP balances shown in Attachment 13 and the budgeted costs shown in Table 1 of Attachment 1A. First, Attachment 13 shows the ADMS project costs at a total NSPM Company level, while Table 1 of Attachment 1A shows the project costs at the Minnesota jurisdictional level. Second, the data in Attachment 13 used to calculate the revenue requirement was derived from the corporate forecast from July 2017. The data in Attachment 1A is a slightly different forecast vintage, which was more recent.

As we examined the differences between Attachments 13 and 1A for the purposes of this Reply, we discovered that the July 2017 data vintage provided in Attachment 13 included some hardware costs. In the initial project budgeting process, some hardware expenses were included in the software parent work order as the project team worked through the various project budget elements. Once project costs were better defined, a new work order was created to capture only hardware costs at which time the hardware costs were separated out of the software parent and moved into the hardware parent. Unfortunately, the new hardware work order was created after the July 2017 forecast was pulled from our budget system for the purposes of this filing.

As discussed in our Petition, we did not intend to request recovery of hardware costs through the rider mechanism. We have updated the ADMS forecast to use a more recent data vintage so that the hardware costs are no longer included in the TCR revenue requirement.

B. ADMS Project Allocation

The Department also requested we describe what the "MN JUR Electric Intangible Composite" allocator is, and support our choice to use different allocators to allocate ADMS costs from the total company level to NSPM and among NSPM's three state jurisdictions. In this section, we provide some general information about the methodologies we use to assign costs, and provide Attachment A to demonstrate the derivation of the MN JUR Electric General Intangible Composite Allocator.

1. General Approach to Cost Allocation and Assignment

Our overall philosophy with regard to costs for all products and services is to record them in a consistent, equitable manner to ensure the costs are recovered from the customers of the entity responsible for incurring the costs. This philosophy is designed to reasonably apportion costs to individual Operating Companies, and to avoid cross-subsidization between the Operating Companies and any non-regulated business activities. We outline below the process we follow to implement this philosophy:

- Tariffed rates shall be used to value tariffed services provided,
- Costs shall be directly assigned to either regulated or non-regulated business activities whenever possible,
- Costs that cannot be directly assigned are common costs, which shall be grouped into homogeneous cost categories. Each cost category shall be allocated based on direct analysis of the origin of costs whenever possible,
- If direct analysis is not possible, common costs shall be allocated based upon indirect cost causation, and
- When neither direct or indirect measures of cost causation can be found, the cost category shall be allocated based upon a general allocator.

Our Cost Allocation and Assignment Manual (CAAM) broadly implements these principles with the NSPM Operating Company by outlining our specific cost assignment and allocation procedures. The Service Agreement between Xcel Energy Services Inc. (XES) and the Operating Companies addresses a subset of our allocation principles and practices – specifying the terms and conditions pursuant to which XES provides products and services to the Company. The CAAM is subject to Commission review and approval in general rate cases; changes to the Service Agreement are submitted for Commission review and approval in Affiliated Interest dockets. The CAAM was most recently approved by the Commission as part of our most recently-concluded electric rate case in Docket No. E002/GR-15-826. The current Service Agreement containing the XES allocation methods was approved by the Commission November 19, 2015 in Docket No. E,G002/AI-15-536.

2. *ADMS Operating Company Cost Allocation*

At the time an Xcel Energy information technology system is initiated, we assess what the system is intended to do, and who will benefit from the system. The allocation methodology that is used to split the capital costs between legal entities (ie, the four Operating Companies, or OpCos) is based on each Operating Company's electric distribution plant asset value compared to the total of all four OpCos.

We show the Operating Company statistics underlying our application of the Electric Distribution Plant at the time the ADMS work order was initiated in July 2013 below:

XES Operating Company Statistics
(As of December 2012 – EMS-Distribution Initiated)

Legal Entity	JDE Company	JDE Bus Unit	FERC Account	Total Electric Distribution $000s	Percentage
NSP-MN	10	889019	581	3,233,192	37.4593%
NSP-WI	11	889119	581	699,829	8.1081%
PSCo	12	889219	581	3,771,256	43.6932%
SPS	13	889319	581	926,936	10.7394%
Total				8,631,213	100.0000%

Note: For purposes of our response to DOC Information Request No. 12, we rounded the NSP-MN percentage to 37 percent.

3. *ADMS Cost Allocation to Jurisdiction within NSPM*

All software-related capital costs are allocated based on a Computer Software Study that evaluates which functions each major software project supports to derive a composite allocator that we call the "MN JUR Electric Intangible Composite." We use the study to determine the proportions of total software that support the production, transmission, and distribution functions. We then multiply those relative function weights by their respective allocation factors to derive a composite, as indicated in the following formula:

Electric Intangible (Software) Composite allocation factor =
production portion from software study * demand allocator +
transmission portion from software study * demand allocator +
distribution portion from software study * customers allocator

In the case of the Minnesota jurisdiction, the resulting composite allocator is approximately 87 percent. We provide Attachment A to demonstrate the calculation of this composite allocation factor. This treatment is consistent with how the equivalent costs were treated in the most recently approved electric rate case.

C. Regional Expansion Criteria and Benefits (RECB) Forecast, December 2016 True-Up, and MISO ROE Interest

The Department requested additional information about RECB revenues and expenses. First, they requested we explain the significant changes observed in the forecasted 2017 and 2018 MISO Schedule 26/26A net revenues relative to the 2013-2016 period. In addition to the reduction in MISO ROE discussed in our Petition, the changes in 2017 and 2018 MISO Schedule 26/26A net revenues is largely due to increased MISO MVP project expenses (Schedule 26A), which has been driven by the increase in the total number of MVP projects. The Schedule 26A Revenue Requirement is calculated in accordance with Attachment MM of the MISO Electric Tariff. NSP pays its load ratio share of the total MISO revenue requirement. While NSP's load ratio share has remained relatively flat year-over-year, the increase in MISO's 26A revenue requirement has resulted in increased expense for NSP. See below for a summary of Schedule 26A activity for the period of 2013 – 2018:

Period	MISO Schedule 26A Revenue Requirement	NSP Approximate Load Ratio Share	NSP Schedule 26A Expense	Source - MISO Revenue Requirement
2013	$86,968,820	9%	$7,779,158	MISO Attachment MM Jan 2013 File
2014	$199,008,539	9%	$17,532,690	MISO Attachment MM Jan 2014 File
2015	$324,717,779	9%	$29,396,731	MISO Attachment MM Jan 2015 File
2016	$495,868,463	9%	$44,022,575	MISO Attachment MM Sep 2016 File
2017	$590,381,111	9%	$50,285,500	MISO Attachment MM Jan 2017 File
2018	$714,596,757	9%	$67,190,021	MISO Schedule 26A Indicative Annual Charges File - April 2017

Second, the Department requested we explain the reasons for the December 2016 RECB true-up. The December 2016 true-up was the result of a timing issue. As we closed the books for December 2016, the Company prepared an estimate related to the Formula Rate true-up. The Company communicated these 2016 actuals in the January compliance filing in Docket No. E002/M-15-891. Subsequently in early 2017, we identified an additional adjustment that was required to reflect the remainder related to 2016. The November 2017 petition in this docket included the adjusted 2016 actuals.

Finally, the Department requested more information about why interest relating to the MISO ROE true-up is not included in the TCR Rider.

The Company's actual interest expenses and revenues are typically not included in ratemaking. Instead, the ratemaking mechanisms rely on the cost of capital applied to the particular scope of the mechanism to determine the appropriate interest to recognize.

The interest related to the MISO ROE resettlement was recorded as interest expense (on the cumulative over-collection of revenue requirements) and interest income (interest received from overbillings) and not transmission expense or transmission revenue. The RECB portions of those amounts were interest income of approximately $0.7 million and interest expense of $1.2 million. This would result in a revenue requirement increase to the TCR of approximately $0.5 million, if the Commission chooses to order its inclusion.

D. Tax Cuts and Jobs Act (TCJA) and Updated Revenue Requirement Calculations

Below we describe the adjustments we have made to the TCR revenue requirement calculations to address the TCJA and other items.

1. TCJA Updates

The Tax Cuts and Jobs Act was signed into law in December 2017 as described by the Company in Comments filed March 2, 2018 in Docket No. E,G999/CI-17-895. In that docket, we discuss how the net effect of the TCJA is expected to be an overall reduction in the Company's revenue requirement. The multiple impacts from tax reform are as follows:

- Current Income Taxes – the change in the federal corporate tax rate from 35% to 21% has a direct impact on the income tax expense and the revenue conversion factor used to "gross up" the revenue requirement items subject to tax to account for the income taxes the company is required to pay.
- Deferred Taxes – the difference between book and tax depreciation results in deferred taxes.

- Bonus Depreciation Changes – for plant additions after the fourth quarter of 2017, bonus depreciation has been eliminated. The loss of bonus depreciation results in lower tax expense, which lowers the ADIT balance and increases rate base.

We have also updated the MISO RECB project line item with the most recent forecast because the TCJA has a significant impact on RECB invoices. Just as the states have been reviewing the impacts of the TCJA on rates, FERC has as well. Income taxes are a component of the Schedule 26/26A revenue requirements and therefore are affected. We provide the current forecast based on FERC actions to date.

2. Other Revenue Requirement Updates

With these Reply Comments, we update several other open items raised by parties:

- As discussed in the Company's response to IR DOC-13 (attached to the Department's Comments as Attachment 1), we identified an additional removal for GIS costs included in the last rate case.
- We updated the actual revenues through March, 2018 to provide more recent tracker information. We have also provided a 2019 sales forecast to illustrate a revised rate calculation over 12 months beginning July 1, 2018.
- The updated ADMS forecast discussed above in Section A has also been incorporated.
- As we discuss below in Section F, we have also made updates to the ADIT proration including the removal of ADIT proration from the 2017 revenue requirements as that test period has ended.

The schedules showing these updates and resulting rate calculations will be provided in a forthcoming supplement.

E. ROE

Attachment B to these Reply Comments provides a detailed response to the Department's and the OAG's ROE analysis and recommendations as prepared by Concentric Energy Advisors (Concentric), the independent expert retained by the Company to advise on this topic. Concentric also outlines several important developments that have affected conditions in capital markets since the time the initial Petition was submitted in November 2017. In summary, Concentric continues to believe that an authorized ROE of 10.00 percent represents a fair determination of the Company's cost of equity for the TCR Rider.

The Department recommends that the ROE from this docket be used until NSPM concludes its next electric rate case. While the Company appreciates the Department's suggestion, recent volatility in the financial markets may make this difficult to implement. Thus, at least for the time being, the Company believes that both shareholders and our customers will benefit from the more current financial information that more frequent review will offer. The Company is willing to revisit this issue in future proceedings to determine a more efficient way to proceed. For example, if financial markets stabilize, we may be able to consider less frequent review of the ROE issue. Finally, we continue to recommend that a single ROE can be applied to all of our riders.

F. ADIT Proration

We acknowledge that the ADIT Proration requirements from the IRS are cumbersome. We took steps to evaluate this topic in significant depth and explore what alternative treatments could be applied across all of the Company's open rider proceedings so as to minimize the customer impact while still maintaining the significant deferred tax benefits provided to our customers. Below we provide a discussion of the Department's proposed resolution of the issue and discuss the additional work we have done as well to bring constructive closure to this issue.

1. Response to the Department

In the Department's Comments, the Department compares the Company's position to the resolution in the Otter Tail Power TCRR proceeding, Docket No. E017/M-16-374, noting:

> *As the tracker is updated with actual results, the effect of proration is eliminated and the actual, non-prorated ADIT amounts are reflected in the TCRR.*

We note that the Otter Tail docket is now two years old, and did not have the benefit of the clarifying guidance from the IRS. Otter Tail has not filed subsequent riders in Minnesota, but it has filed subsequent riders in other jurisdictions. For example, in their January 29, 2018 supplement to a rider in South Dakota, Docket No. EL17-048, Otter Tail writes:

> *Proration of Federal Accumulated Deferred Income Taxes (ADIT): Based on further research and analysis of United States Internal Revenue Service (IRS) rules related to proration, including recently issued IRS private letter rulings, Otter Tail identified revisions needed to its Accumulated Deferred Income Tax (ADIT) balances to preserve the effect of the application of the proration methodology for the true-up period. This calculation methodology is necessary in order to comply with Section 1.167(l)-l(h)(6)(ii) of the IRS regulations and to avoid a tax normalization violation.*

The Department also notes that Private Letter Rulings (PLRs) are not the same as IRS Regulations and every PLR is only for the entity requesting the PLR. The Company notes that nonetheless, PLRs represent the IRS' view of the application of the law to a specific set of facts. Thus, the IRS makes their PLR findings public so that parties with similar fact patterns can learn from the circumstances addressed in the PLR.

The Department notes that by implementing the ADIT prorate, debits and credits would no longer be equal in the ratemaking calculation. It also notes that ADIT would be treated differently from the rest of rate base, which follows a BOY/EOY average without a proration effect. The Company notes that tax normalization is required in order to use accelerated depreciation, and Treasury Regulation §1.167(l)(h)(6) requires a proration of forecasted ADIT to comply. Without changing the law or the regulation, the Company sees no way to avoid this circumstance.

The Department notes that the Company is not incurring any additional costs to warrant such a change in long-standing ratemaking policy. The Company notes that Treasury Reg. §1.167(l)(h)(6) has been in place since the 1970s. Through a series of PLRs over the past few years, the IRS highlighted that many utilities and regulators had not been complying with this provision in their ratemaking practices. The Company has no particular interest in the provision other than it is required in order to preserve the significant deferred tax benefits for our customers and the IRS has communicated to the industry the ways in which it should be implemented.

2. Additional Work and Interpretation

The Company has reviewed recently-released IRS guidance and engaged Deloitte Tax Services to evaluate our rider calculations and propose further optimizations that could be applied to reduce or effectively eliminate the impact to customers. Through this process we identified a possible modification, which is to treat each forecast month as a test period since the revenue requirements in these riders are calculated monthly. This allows the monthly ADIT balance to be reset to its un-prorated beginning balance and only the monthly activity receives the proration. This treatment reduces the impact to the ratepayers in these rider mechanisms. We are finalizing these calculations and will provide a supplement to this Reply to provide the detailed schedules and impacts of this methodology.

With these changes we feel we have taken as many steps as possible to minimize the issue. We ask that the Commission allow current recovery using this treatment rather than waiting to set the rate after the test period as that is punitive to the Company and potentially volatile for customer rates.

Even without this potential optimization, we believe our position on true-up treatment is in fact quite close to the Department's. In their Comments, the Department restated their position from our last Transmission Cost Recovery (TCR) proceeding, Docket No. E002/M-15-891:

> *Based on our review of IRS Section 1.167(l)(h)(6), the Department concludes that the ADIT issue is simply a timing issue. Once actual non-prorated ADIT balances are known in the following year, they should replace the forecasted prorated ADIT balances in the beginning-of-year and end-of-year average ADIT balance calculations for true-up purposes.*

We note that the proposal provided in our response to IR DOC-3 in the RES Rider docket,[1] attached here as Attachment C, is a slight modification to the Department's position above, and is based on the most recent and relevant guidance from the IRS. Our proposed treatment also uses actuals to replace the forecasted prorated ADIT balances in the beginning-of-[period] and end-of-[period] average ADIT balance calculations for true-up purposes. The only difference is the clarification that neither the original forecast nor the actual results are prorated for the purposes of the comparison used in the true-up.

The Department goes on to say, again quoting from the TCR docket:

> *Alternatively, the Commission could require Xcel's riders to be based solely on historical costs, as Xcel acknowledges that the issue applies only in cases with forward-looking rates.*

We continue to believe this purely historical method, while definitive, provides significant drawbacks to our customers. The revenue requirements value of the prorate is quite small. However postponing the rate implementation past the test

[1] Docket No. E002/M-17-818

year, in this case 2018, would create a large carryover balance to be recovered in the next rate. This creates unnecessarily large volatility in the rider rates year-to-year.

We appreciate the input and discussion the Department has provided thus far in what we acknowledge to be a complex topic. Given the minimal difference that now exists between the parties' interpretations, the Company would be interested in follow-up discussions to determine if any additional adjustments can result in a satisfactory outcome for all parties. Additionally, we believe that, given the additional guidance received from recent IRS rulings and work with Deloitte Tax Services, it is no longer necessary for the Company to submit its own PLR. We look forward to resolving remaining differences with parties.

G. Proposed Carrying Charge

We appreciate the Department's review of the Commission's findings in Docket No. E017/M-13-103. We agree with the Commission's order in that docket that a carrying charge is "unnecessary either to ensure fairness or to act as an incentive." However the issue in the Company's riders is neither one of fairness nor incentive, but rather one of customer impact.

The Company discussed this in response to IR OAG-203, which the Department references, which we provide as Attachment D to these Reply Comments.

The Company has observed that as evaluation periods have lengthened and as rate implementation periods have been ordered so as to avoid customer impacts, carryover balances have been getting quite large. These carryover balances then create significant volatility in the subsequent period revenue requirements and thus the subsequent rates to charge to customers. This creates a cycle in which further deviations from the test period to the implementation period are ordered.

The Company seeks an approximate match between the test period and the implementation period so as to avoid such circumstances and resulting volatility on customer bills. The Company sees a carrying charge as one tool to encourage that match.

CONCLUSION

We appreciate the opportunity to respond to the Comments submitted by the Department and the OAG. We respectfully request the Commission approve our petition as supplemented through this Reply.

Dated: May 14, 2018

Northern States Power Company

Based on Computer Software Study

	Sub Business Unit - Electric		
a	Production	36.5882%	Computer Software Study
b	Transmission	54.0551%	Computer Software Study
c	Distribution	9.3567%	Computer Software Study
d=a+b+c		100.0000%	
	Jurisdiction Allocation - Electric		
	Production and Transmission		
		Electric Demand Allocator	
e	MN Electric Jurisdiction Demand	87.3461%	Docket No. E002/GR-15-826, Vol. 4A, Page B2-6
f	ND Electric Jurisdiction Demand	6.2102%	Docket No. E002/GR-15-826, Vol. 4A, Page B2-6
g	SD Electric Jurisdiction Demand	6.4437%	Docket No. E002/GR-15-826, Vol. 4A, Page B2-6
h = e+f+g	Total NSPM Electric Demand	100.0000%	
	Distribution		
		Electric Customer Allocator	
i	MN Electric Jurisdiction Customers	87.3525%	Docket No. E002/GR-15-826, Vol. 4A, Page B1-2
j	ND Electric Jurisdiction Customers	6.4276%	Docket No. E002/GR-15-826, Vol. 4A, Page B1-2
k	SD Electric Jurisdiction Customers	6.2199%	Docket No. E002/GR-15-826, Vol. 4A, Page B1-2
l = i+j+k	Total NSPM Electric Customers	100.0000%	
	Electric General Intangible Composite Allocator		
		Electric General Intangible Composite Allocator	
m=(a*e)+(b*e)+(c*i)	MN Electric Jurisdiction Intangible Composite	87.3467%	
n=(a*f)+(b*f)+(c*j)	ND Electric Jurisdiction Intangible Composite	6.2305%	
o=(a*g)+(b*g)+(c*k)	SD Electric Jurisdiction Intangible Composite	6.4228%	
p = m+n+o	Total NSPM Electric Intangible Composite	100.0000%	

REPLY COMMENTS:

COST OF EQUITY – TCR RIDER

PREPARED FOR

NORTHERN STATES POWER COMPANY - MINNESOTA

BEFORE THE:

MINNESOTA PUBLIC UTILITIES COMMISSION

MAY 14, 2018

www.ceadvisors.com

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I. INTRODUCTION AND PURPOSE

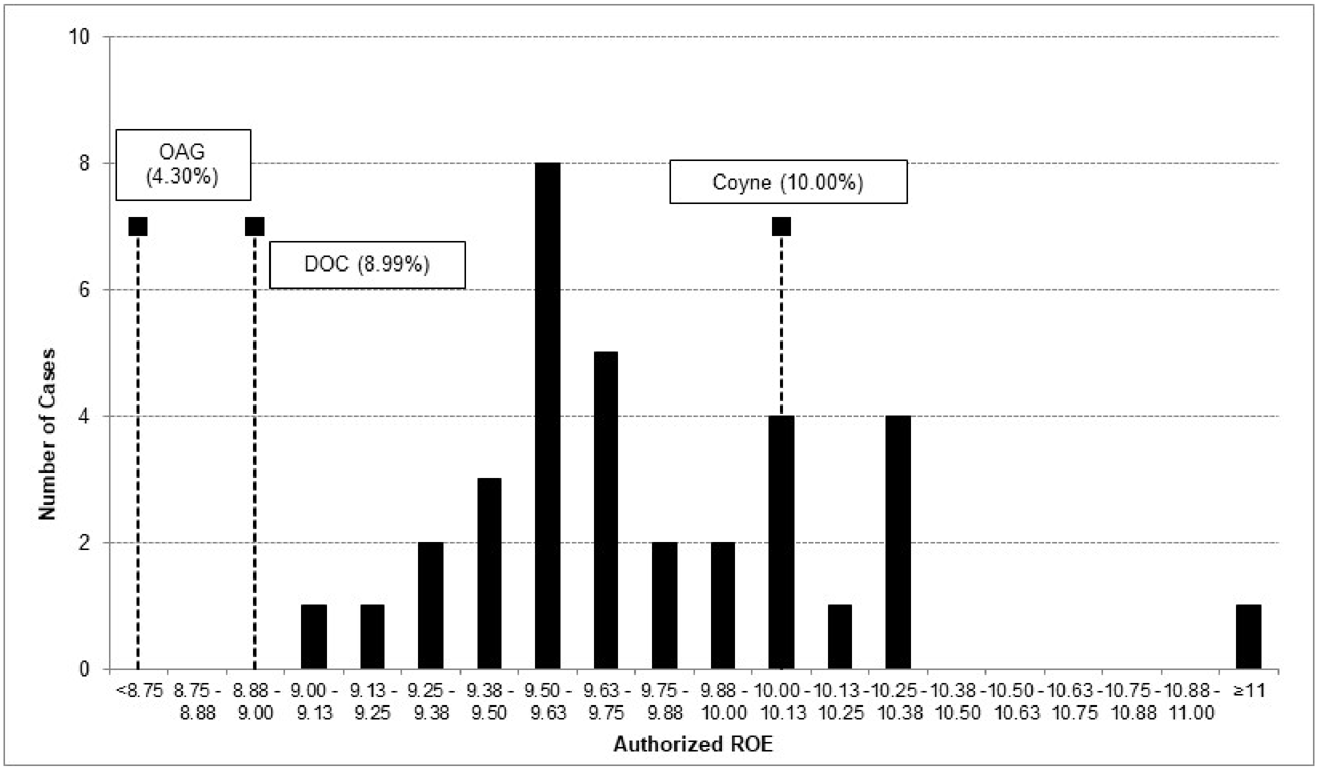
The purpose of these reply comments is to respond to the analysis and recommendations submitted by the Department of Commerce ("DOC") and the Office of the Attorney General ("OAG") regarding the appropriate return on equity ("ROE") for Northern States Power Company's ("NSPM") Transmission Cost Recovery ("TCR") rider. The reply comments are organized as follows: Section II responds to the DOC's analysis and recommendation; Section III responds to the OAG's analysis and recommendation; Section IV provides a discussion of how capital market conditions have changed since the filing of the petition; Section V provides updated DCF, Risk Premium and CAPM results; and Section VI summarizes my conclusions and recommendations.

II. RESPONSE TO DEPARTMENT OF COMMERCE

The DOC recommends an ROE of 8.99 percent for NSPM's TCR rider, based on the mean results of its two-growth DCF model for an Electric Proxy Group and a Combined Proxy Group. The DOC also conducts a CAPM analysis for the two proxy groups, but does not place any weight on that analysis. The DOC observes that the Minnesota Public Utilities Commission has traditionally relied primarily on the results of the DCF analysis, and that "while the Department's CAPM results are higher than its high DCF results, they fall within the ranges established by the Department's high two-growth DCF analyses, and therefore confirm the reasonableness" of the DCF results.

Authorized returns on equity for integrated electric utilities in other state jurisdictions indicate that comparable risk utility investments elsewhere have received equity returns well above the levels recommended by the DOC and the OAG in this proceeding. The national average authorized ROE for integrated electric utilities from January 2017 through March 2018 was 9.78 percent. As shown in Figure 1, my 10.0 percent ROE recommendation is consistent with range of returns authorized for integrated electric utilities in 2017 and 2018, while the DOC's and OAG's ROE recommendations fall outside the range of authorized equity returns during this period.

Figure 1: U.S. Authorized Returns on Equity – January 2017 thru March 2018[1]



The DOC's recommendation of 8.99 percent in this proceeding is lower than the bottom of the range of authorized ROEs in all 50 rate case decisions involving integrated electric utilities in other jurisdictions. The DOC has not provided any evidence to support a conclusion that there are differences in business or financial risk that would justify an ROE for NSPM's TCR rider below any authorized ROE for an integrated electric utility in 2017 or 2018.

On the contrary, the DOC's own analysis, summarized in Figure 2, supports my ROE recommendation of 10.0 percent for NSPM's TCR rider.

[1] Source: SNL Financial.

Figure 2: Summary of DOC's ROE results

	Mean low	Mean	Mean high
Two-growth DCF – Electric	8.12%	8.80%	9.76%
Two growth DCF - Combination	8.37%	9.28%	10.06%
CAPM – Electric		11.01%	
CAPM – Combined		10.90%	
Average DCF & CAPM - Electric		**9.91%**	
Average DCF & CAPM - Combined		**10.09%**	
Average of all Methods		**10.00%**	

Giving equal weight to the DCF and CAPM results shown in Figure 2 produces an ROE estimate of 9.91 percent for the Electric Proxy Group and 10.09 percent for the Combination Proxy Group. The average of all methods is 10.0 percent, which is the same as my recommendation. The results of the DOC's CAPM analysis, which the DOC indicates should be used as a check on the reasonableness of the DCF results, are significantly higher than the results of the DOC's Two-growth DCF analysis for the Electric and Combination proxy groups. The DOC concludes that while the CAPM results are higher than the high DCF results, they fall within the range established by the DOC's high two-growth DCF analysis, and therefore confirm the reasonableness of the DCF results. As shown in Figure 2, the mean CAPM results for both the Electric and Combination proxy groups are between 84 and 125 basis points higher than the Two-growth DCF results. The results of the DOC's own CAPM analysis provide ample support for my position that the Commission should recognize that the DCF model is not producing reliable results under current market conditions, and should consider the results of alternative methodologies including the CAPM analysis and the Risk Premium analysis in order to establish the ROE for NSPM's TCR rider in this proceeding.

As explained in Concentric's Cost of Equity – TCR Rider Report ("TCR Report," dated November 2017), the DCF model is understating the return on equity under current market conditions because the dividend yield component of the DCF is being suppressed by the low interest rate environment, which has been characterized by the Federal Energy Regulatory

Commission ("FERC") as "anomalous". Although the DOC disputes whether market conditions remain anomalous, as shown in Section IV of these reply comments, while interest rates have continued to increase since the filing of the petition, the 10-year and 30-year Treasury bond yields remain well below historical levels.

The FERC's decisions in Opinion No. 531, 531-B, and 551 are especially relevant because the FERC, like the Minnesota Commission, had traditionally relied primarily on the results of the DCF model. However, the FERC determined that capital market conditions after the Great Recession have caused the results of the DCF model to be less than reliable. For that reason, the FERC determined that it was appropriate and necessary to also consider the results of alternative risk-premium based models, such as the Risk Premium analysis and the CAPM, in order to determine where, within the range of reasonable DCF results, to set the authorized ROE for transmission companies.

In addition to the FERC's decisions in Opinion Nos. 531 and 551, other state utility regulators have recognized that current market conditions are distorting the results of the DCF model. For example, decisions of the Pennsylvania Public Utility Commission ("PPUC") and the Missouri Public Service Commission ("Missouri PSC") provide useful guidance on how those Commissions have reflected market conditions in the authorized ROE.

In a 2012 decision for PPL Electric Utilities, the PPUC noted that it has traditionally relied primarily on the DCF method to estimate the cost of equity for regulated utilities; however, the PPUC recognized that market conditions were causing the DCF model to produce results that were much lower than other models such as the CAPM and Bond Yield Plus Risk Premium. The PPUC's Order explained:

> Sole reliance on one methodology without checking the validity of the results of that methodology with other cost of equity analyses does not always lend itself to responsible ratemaking. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived equity return calculation.[2]

[2] Pennsylvania Public Utility Commission, PPL Electric Utilities, R-2012-2290597, meeting held December 5, 2012, at 80.

The PPUC ultimately concluded:

> As such, where evidence based on the CAPM and RP methods suggest that the DCF-only results may understate the utility's current cost of equity capital, we will give consideration to those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination.[3]

In February 2018, the Missouri PSC issued a decision in Spire's 2017 gas rate case, in which the allowed ROE was set at 9.80 percent. In explaining the rationale for its decision, the Commission cited the importance of considering multiple methodologies to estimate the cost of equity and the need for the authorized ROE to be consistent with returns in other jurisdictions and to reflect the growing economy and investor expectations for higher interest rates.

> …the Commission finds that 9.8 percent is a fair and reasonable return on equity for Spire Missouri. That rate is nearly the midpoint of all the experts' recommendations and is consistent with the national average, the growing economy, and the anticipated increasing interest rates. The Commission finds that this rate of return will allow Spire Missouri to compete in the capital market for the funds needed to maintain its financial health.[4]

The DOC also objects to my use of projected interest rates in the CAPM and Risk Premium models. As explained in Concentric's TCR Report, I placed more weight on interest rate forecasts than on current interest rates because investors are expecting higher interest rates over the course of the next few years. The use of projected interest rates in the CAPM analysis is supported by a 2017 decision from the Massachusetts Department of Public Utilities ("MDPU"). In DPU 17-05, the MDPU noted that current monetary policy has pushed Treasury yields to near historic lows. Therefore, the MDPU found that it is appropriate to use prospective interest rates in the CAPM.[5]

> Current federal monetary policy that is intended to stimulate the economy has pushed treasury yields to near historic lows. Consequently, the Department has found that a CAPM analysis based on current treasury yields

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[3] *Id.*, at 81.
[4] File No. GR-2017-0215 and File No. GR-2017-0216, Missouri Public Service Commission, Report and Order, Issue Date February 21, 2018, at 34.
[5] D.P.U. 17-05, at 693.

> may tend to underestimate the risk-free rate over the long term and, thereby, understate the required ROE. The CAPM is based on investor expectations and, therefore, it is appropriate to use a prospective measure for the risk-free rate component. The Department has found that Blue Chip Financial Forecasts is widely relied on by investors and provides a useful proxy for investor expectations for the risk-free rate.[6]

In sum, the DOC's analysis and recommended ROE for NSPM's transmission rider fails to consider the results from other (non-DCF) models, which is a weakness recognized by other regulators. Bringing the DOC's own CAPM results into the analysis, especially in today's market circumstances, is entirely appropriate and would yield results comparable to my recommendation and consistent with allowed ROEs for other vertically-integrated electric utilities.

III. RESPONSE TO OFFICE OF THE ATTORNEY GENERAL

The OAG recommends an ROE of 4.30 percent for NSPM's TCR rider, based on Xcel Energy's weighted-average long-term debt cost. The OAG indicates that it also considered an ROE of 2.30 percent, which is the average yield on 2-year Treasury bonds. The OAG did not present the results of traditional DCF, CAPM or Risk Premium models to estimate the cost of equity for NSPM's TCR rider.

An authorized ROE in the range of 2.30 to 4.30 percent is substantially below any authorized return on equity for an integrated electric utility going back to at least 1977, which is the historical period covered by the RRA database. Such a return is not just and reasonable, and does not meet the three standards established in the *Hope* and *Bluefield* decisions for a fair return:

1) Sufficient to attract capital on reasonable terms;
2) Sufficient to maintain the financial integrity of the company; and
3) Provides a return comparable to other investments with commensurate risk.

The OAG's recommended ROE of 4.30 percent does not take into consideration the risks associated with common equity ownership, including the risk that dividends are not guaranteed

[6] D.P.U. 17-05 Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each doing business as Eversource Energy, Pursuant to G.L. c. 164, § 94 and 220 CMR 5.00 et seq., for Approval of General Increases in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Mechanism, November 30, 2017, at 693.

to shareholders and the risk that shareholders are the residual claimants on the earnings of the company in the event of financial distress or bankruptcy. Equity investors must be compensated for taking on these risks of ownership through a higher return than what is available to debt holders. The OAG's ROE recommendation violates this basic financial principle.

Furthermore, the OAG's recommendation to base the ROE on Xcel Energy's long-term debt cost is not consistent with the way in which NSPM finances the approximately $1.2 billion in cumulative transmission projects that have been included in TCR rider since its inception. Specifically, NSPM finances TCR investments using a mix of equity and debt capital. It is not reasonable to set NSPM's authorized ROE for the TCR rider based on long-term debt costs because the Company is using both equity and debt to finance these large transmission projects. The purpose of the TCR rider is to allow NSPM to recover the costs (including financing costs) associated with these types of projects before they are placed into service and added to rate base in a future rate case.

The OAG attempts to argue that the risk associated with cost recovery through riders such as the TCR is more analogous to the risk of holding long-term debt than to the risk of equity ownership. The OAG is essentially treating the TCR rider as if it were a deferral or variance account rather than a cost recovery mechanism for major capital investment projects. This is not reasonable and should not be the basis used by the Commission for establishing an appropriate equity return for the TCR rider.

The OAG cites a decision of the Iowa Utilities Board in Docket No. RMU-11-0002, which it claims supports the OAG's use of a long-term debt cost as the equity return for a rider. The Iowa decision was issued in a 2011 rule making docket for gas distribution utilities, in which the question arose as to the appropriate return for an infrastructure replacement cost rider for gas utilities. The IUB determined that the return should be equal to the long-term debt cost that was approved in the utility's most recent rate case.

However, Minnesota statutes related to the TCR rider provide the necessary precedent for the Commission; it is not necessary to look to rules for Iowa gas distribution utilities as precedent. As discussed in the original report, the Commission's determination of the appropriate rate of return for the TCR rider looks to the ROE allowed in the Company's last general rate case, unless the Commission determines that a different rate of return is in the public interest.[7] In this instance, NSPM's last general electric rate case was decided in May 2017, when the Company's ROE was set at 9.20 percent as part of a negotiated settlement. In its decision approving the settlement, the Commission stated that "the Settlement does not prevent any party from contesting the ROE when it is applied in rider dockets or other proceedings" and that "parties will be free to assert an alternative ROE at that time."[8] On that basis, Concentric presented an updated cost of equity analysis in support of its recommendation. OAG's recommended ROE based on long-term debt costs for Xcel Energy is not just and reasonable, and should be disregarded by the Commission.

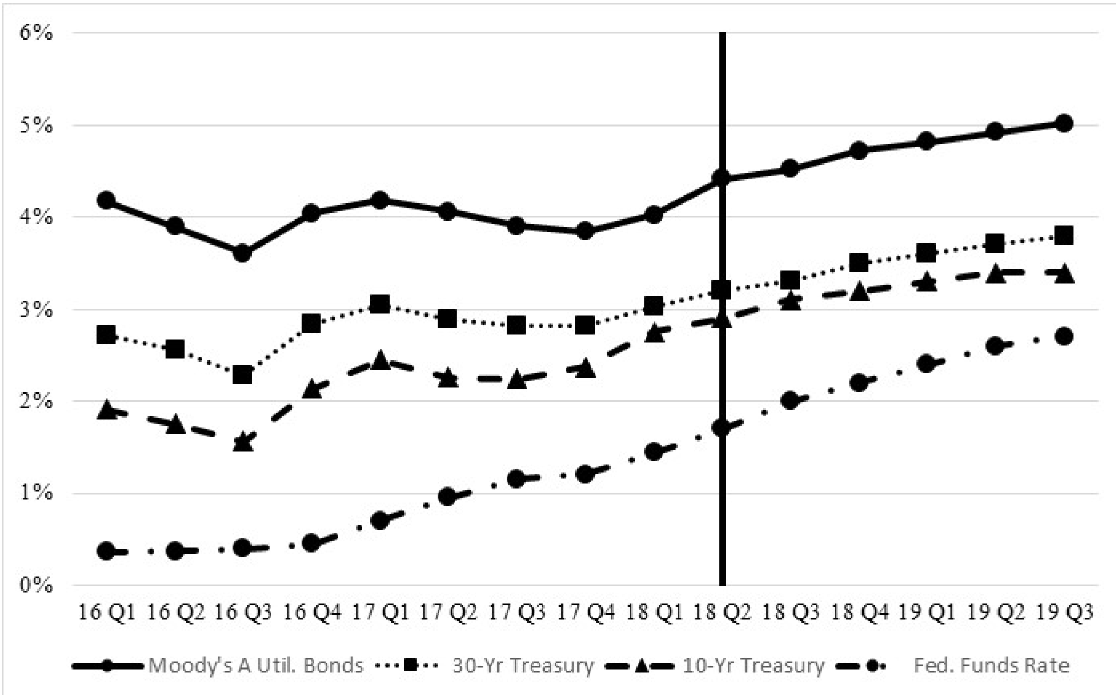
IV. UPDATED CAPITAL MARKET CONDITIONS

Concentric's TCR Report provided an overview of capital market conditions and the implications of those conditions for the cost of equity. Since the filing of that report, there have been several important developments that have affected conditions in capital markets. Those are summarized in this section of the reply comments.

Since the TCR Report was filed, the Federal Reserve has continued to tighten monetary policy, raising the federal funds rate by 25 basis points in both December 2017 and March 2018, for a total increase of 50 basis points since the Company's petition was filed. As noted in Concentric's TCR Report, the 10-year Treasury bond yield was 2.33 percent on September 29, 2017. As of May 9, 2018, the 10-year Treasury bond yield has increased to 3.00 percent, or 67 basis points higher. According to Blue Chip Financial Forecasts, the yield on the 10-year Treasury is projected to increase to 3.20 percent by the 4th quarter of 2018 and 3.40 percent by the 3rd quarter of 2019, and the yield on the 30-year Treasury is projected to increase to 3.50 percent in the 4th quarter of 2018 and 3.80 percent by the 3rd quarter of 2019. I have updated Figure 3 from the TCR report to show the latest actual and projected interest rate conditions.

7 Minn. Statute 216B.16, subd.7b.
8 E-002/GR-15-0826, May 11, 2017, at 22.

Figure 3: Interest Rate Conditions[9]



Furthermore, in October 2017, the Federal Open Market Committee ("FOMC") started reducing the size of the Fed's $4.5 trillion bond portfolio by no longer reinvesting the proceeds of the bonds it holds. In response to the Great Recession, the Fed pursued a policy known as "Quantitative Easing," in which it systematically purchased mortgage-backed securities and long-term Treasury bonds to provide liquidity in financial markets and drive down yields on long-term government bonds. Although the Federal Reserve discontinued the Quantitative Easing program in October 2014, it continued to reinvest the proceeds from the bonds it holds. Under the new policy, the FOMC intends to gradually reduce the Federal Reserve's securities holdings by $10 billion per month initially, ramping up to $50 billion per month by the end of the first twelve months.[10]

In addition, in December 2017, federal tax reform legislation was passed by the U.S. Congress and signed into law by the President. Tax reform has placed upward pressure on interest rates

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[9] Source: Historical data from Bloomberg Professional. Forecast data from Blue Chip Financial Forecasts, Volume 37, No. 4, April 1, 2018, at 2.

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

due to concerns about how lower tax collections will affect the U.S. federal budget deficit, as well as the need for more borrowing by the Treasury to fund the U.S. government.

The major credit rating agencies (i.e., Moody's, S&P and Fitch) all have indicated that tax reform is credit negative for the utility industry because it reduces the cash flows of utilities. Tax reform is expected to reduce utility revenues due to the lower federal income taxes and the requirement to return excess accumulated deferred income taxes ("ADIT"). This change in revenue is expected to reduce funds from operations ("FFO") metrics across the sector and, absent regulatory mitigation strategies, lead to weaker credit metrics and negative ratings actions for some utilities.[11]

Moody's Investors Services ("Moody's") indicated that while tax reform was credit positive for many sectors, it has an overall negative credit impact on regulated utility operating companies and their holding companies due to the reduction in cash flow metrics that results from the change in the federal tax rate and the loss of bonus depreciation. The lower tax rate combined with the loss of bonus depreciation will have a negative effect on utility cash flows for three primary reasons.

1) Utilities will collect less taxes at the lower rate, reducing revenue. While the taxes are ultimately paid out as an expense, under the new law utilities lose the timing benefit, reducing cash that may have been carried over a number of years.
2) Lowering taxes also creates an overcollection that must be refunded to customers.
3) The loss of bonus depreciation means that utilities will be paying taxes starting in 2019 and 2020, earlier than under the prior tax law. This increases the taxable income of the utility.[12]

Moody's expects that the effect of these changes will be a decline in key financial cash flow-to-debt metrics for utilities. In January 2018, Moody's lowered the rating outlook for two dozen regulated utilities from Stable to Negative, noting that the change affected companies with

[11] FitchRatings, Special Report, What Investors Want to Know, "Tax Reform Impact on the U.S. Utilities, Power & Gas Sector", January 24, 2018.
[12] Moody's Investors Services, "Tax Reform- US: Corporate tax cut is credit positive, while effects of other provisions vary by sector", December 21, 2017, at 6-7.

limited cushion in their ratings for deterioration in financial performance. Tax reform results in the expectation that key credit metrics will remain lower for a longer period. Furthermore, Moody's expects that it will be necessary for utilities to work with regulators to try to mitigate the impact of tax reform.[13]

Standard and Poor's ("S&P") published a report on January 24, 2018 entitled "U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound" in which S&P concludes:

> The impact of tax reform on utilities is likely to be negative to varying degrees depending on a company's tax position going into 2018, how its regulators react, and how the company reacts in return. It is negative for credit quality because the combination of a lower tax rate and the loss of stimulus provisions related to bonus depreciation or full expensing of capital spending will create headwinds in operating cash-flow generation capabilities as customer rates are lowered in response to the new tax code. The impact could be sharpened or softened by regulators depending on how much they want to lower utility rates immediately instead of using some of the lower revenue requirement from tax reform to allow the utility to retain the cash for infrastructure investment or other expenses. Regulators must also recognize that tax reform is a strain on utility credit quality, and we expect companies to request stronger capital structures and other means to offset some of the negative impact.
>
> Finally, if the regulatory response does not adequately compensate for the lower cash flows, we will look to the issuers, especially at the holding company level, to take steps to protect credit metrics if necessary. Some deterioration in the ability to deduct interest expense could occur at the parent, making debt there relatively more expensive. More equity may make sense and be necessary to protect ratings if financial metrics are already under pressure and regulators are aggressive in lowering customer rates. It will probably take the remainder of this year to fully assess the financial impact on each issuer from the change in tax liabilities, the regulatory response, and the company's ultimate response. We have already witnessed differing responses. We revised our outlook to negative on PNM Resources Inc. and its subsidiaries on Jan. 16 after a Public Service Co. of New Mexico rate case decision incorporated tax savings with no offsetting measures taken to alleviate the weaker cash flows. It remains to be seen whether PNM will

[13] Moody's Investor Services, Global Credit Research, Rating Action: Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform, January 19, 2018.

> eventually do so, especially as it is facing other regulatory headwinds. On the other hand, FirstEnergy Corp. issued $1.62 billion of mandatory convertible stock and $850 million of common equity on Jan. 22 and explicitly referenced the need to support its credit metrics in the face of the new tax code in announcing the move. That is exactly the kind of proactive financial management that we will be looking for to fortify credit quality and promote ratings stability.[14]

In response to higher interest rates and tax reform, the S&P Utilities Index has declined by approximately 10 percent since mid-November 2017. As shown in Section V of these reply comments, the Constant Growth DCF model mean results have increased by 38 basis points since Concentric's TCR Report was filed, demonstrating the sensitivity of utility stock prices to changes in interest rates and the upward trajectory of the cost of capital, including the utility cost of equity. Figure 4 shows how the S&P Utilities Index has responded to these fundamental changes in capital market conditions.

Figure 4: S&P Utilities Index and U.S. Treasury Bond Yields – 06/2017 – 03/2018[15]

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[14] Standard and Poor's Global Ratings, "U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound," January 24, 2018.

[15] Source: SNL Financial.

These changes in capital market conditions suggest that capital costs for regulated utilities have increased since Concentric's TCR Report was filed. Section V examines how each ROE estimation model has been affected.

V. UPDATED ROE ANALYSES

Concentric has updated the results of the Constant Growth DCF analysis, Risk Premium analysis, and CAPM analysis based on market data through April 30, 2018, using the same proxy group and the same methodologies as in the TCR report. The updated analyses are presented in Appendix 1, Schedules 1 through 3.3.

A. <u>Constant Growth DCF Analysis</u>

The Constant Growth DCF analysis has been updated using stock prices and growth rates as of April 30, 2018. The updated results are presented in Figure 5.

Figure 5: Constant Growth DCF Results

	Mean Low	Mean	Mean High
30-day average	7.86%	8.76%	9.52%
90-day average	7.85%	8.75%	9.51%
180-day average	7.64%	8.54%	9.30%

B. <u>Risk Premium Analysis</u>

The Risk Premium analyses have also been updated; the first risk premium analysis is based on the relationship between quarterly average allowed ROEs for vertically-integrated electric utility companies and the respective 30-year Treasury yield from the relevant quarter from 1993 through April 30, 2018.

Figure 6: 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[16]	Using Long-Term Forecast for Yield 30-Year Treasury Bond[17]
Yield	3.07%	3.58%	4.10%
Risk Premium	6.79%	6.50%	6.22%
Resulting ROE	9.86%	10.08%	10.32%

The second risk premium analysis is based on the same quarterly average allowed ROEs for vertically-integrated electric utilities compared to the corresponding yield on the Moody's A-rated utility bond yield using data from 1993 through April 30, 2018.

Figure 7: 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	4.16%	4.80%	5.32%
Risk Premium	5.60%	5.23%	4.94%
ROEs	9.76%	10.03%	10.26%

C. CAPM Analysis

The CAPM analysis has been updated using the Blue Chip forecast of the yield on 30-year Treasury bonds for 2019-2023 of 4.10 percent as the risk-free rate,[18] Betas from Bloomberg and Value Line, and a forward-looking market risk premium based on the total return on the S&P 500 less the risk-free rate. The updated CAPM results are shown in Figure 8.

16 Blue Chip consensus forecast for 2Q 2018 – 3Q 2019, as of May 1, 2018.
17 Blue Chip consensus forecast for 2019 – 2023, as of December 1, 2017.
18 Blue Chip Financial Forecasts, December 1, 2017, at 14.

Figure 8: Forward-Looking CAPM Results

Using Value Line Betas	11.71%
Using Bloomberg Betas	10.47%
Mean Result	11.09%

VI. SUMMARY AND CONCLUSIONS

Figure 9 summarizes the updated mean results of the DCF, Risk Premium and CAPM analyses for the electric utility proxy group as compared to the original report.

Figure 9: Summary of ROE Model Results

DCF Model – 90-day average stock price	**Filing – Data as of 9/30/17**	**Update – Data as of 4/30/18**
Constant Growth	8.19%	8.75%
Risk Premium		
30 Yr. U.S. Treasury	10.41%	10.32%
Moody's A-rated Utility Index	10.36%	10.26%
CAPM		
Value Line Beta	10.78%	11.71%
Bloomberg Beta	9.52%	10.47%
Mean of All Methods	**9.85%**	**10.30**%

The original results ranged from 8.19 percent (Constant Growth DCF analysis) to 10.78 percent (CAPM analysis). The mean of all methods for the proxy group was 9.85 percent. The updated results demonstrate that the cost of equity has increased between September 2017 and April 2018. The Constant Growth DCF mean results have increased by 56 basis points, the CAPM results have increased between 93 and 95 basis points depending on the source of Beta, while the Risk Premium results have decreased by 9 to 10 basis points. The updated mean of all methods for the proxy group has increased by 45 basis points to 10.30 percent.

Based on this updated analysis, I continue to believe that an authorized ROE of 10.0 percent represents a fair, if not conservative, determination of NSPM's cost of equity for the TCR rider.

30-DAY CONSTANT GROWTH DCF

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] Yahoo! Finance Earnings Growth	[7] Zacks Earnings Growth	[8] Average Growth Rate	[9] Mean Low ROE	[10] Overall Mean ROE	[11] Mean High ROE
ALLETE, Inc.	ALE	$2.24	$72.64	3.08%	3.17%	4.50%	6.00%	6.60%	5.70%	7.65%	8.87%	9.79%
Alliant Energy Corporation	LNT	$1.34	$41.09	3.26%	3.36%	6.50%	5.80%	5.60%	5.97%	8.95%	9.33%	9.87%
Ameren Corporation	AEE	$1.83	$56.39	3.25%	3.36%	7.50%	n/a	6.80%	7.15%	10.16%	10.51%	10.87%
American Electric Power Company, Inc.	AEP	$2.48	$68.31	3.63%	3.73%	4.50%	5.74%	5.40%	5.21%	8.21%	8.94%	9.47%
Duke Energy Corporation	DUK	$3.56	$77.67	4.58%	4.67%	3.70%	4.25%	3.90%	3.95%	8.37%	8.62%	8.93%
El Paso Electric Company	EE	$1.34	$49.91	2.69%	2.75%	4.50%	5.20%	4.90%	4.87%	7.25%	7.62%	7.95%
Hawaiian Electric Industries, Inc.	HE	$1.24	$34.34	3.61%	3.73%	3.50%	8.60%	6.80%	6.30%	7.17%	10.03%	12.37%
IDACORP, Inc.	IDA	$2.36	$88.00	2.68%	2.73%	3.50%	3.10%	3.90%	3.50%	5.82%	6.23%	6.63%
OGE Energy Corporation	OGE	$1.33	$32.29	4.12%	4.22%	2.50%	5.80%	6.00%	4.77%	6.67%	8.98%	10.24%
Pinnacle West Capital Corporation	PNW	$2.78	$79.13	3.51%	3.58%	5.00%	3.63%	3.00%	3.88%	6.57%	7.46%	8.60%
PNM Resources, Inc.	PNM	$1.06	$38.15	2.78%	2.86%	7.50%	4.30%	5.40%	5.73%	7.14%	8.59%	10.38%
Portland General Electric Company	POR	$1.36	$40.39	3.37%	3.41%	2.90%	2.65%	2.90%	2.82%	6.06%	6.23%	6.32%
PPL Corporation	PPL	$1.64	$28.00	5.86%	6.03%	6.00%	n/a	6.00%	6.00%	12.03%	12.03%	12.03%
Southern Company	SO	$2.32	$44.78	5.18%	5.28%	4.50%	2.71%	4.50%	3.90%	7.96%	9.19%	9.80%
MEAN				3.69%	3.78%	4.76%	4.82%	5.12%	4.98%	7.86%	8.76%	9.52%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of April 30, 2018
[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	$2.24	$71.52	3.13%	3.22%	4.50%	6.00%	6.60%	5.70%	7.70%	8.92%	9.84%
Alliant Energy Corporation	LNT	$1.34	$40.21	3.33%	3.43%	6.50%	5.80%	5.60%	5.97%	9.03%	9.40%	9.94%
Ameren Corporation	AEE	$1.83	$56.02	3.27%	3.38%	7.50%	n/a	6.80%	7.15%	10.18%	10.53%	10.89%
American Electric Power Company, Inc.	AEP	$2.48	$68.20	3.64%	3.73%	4.50%	5.74%	5.40%	5.21%	8.22%	8.94%	9.48%
Duke Energy Corporation	DUK	$3.56	$78.11	4.56%	4.65%	3.70%	4.25%	3.90%	3.95%	8.34%	8.60%	8.90%
El Paso Electric Company	EE	$1.34	$50.87	2.63%	2.70%	4.50%	5.20%	4.90%	4.87%	7.19%	7.56%	7.90%
Hawaiian Electric Industries, Inc.	HE	$1.24	$34.17	3.63%	3.74%	3.50%	8.60%	6.80%	6.30%	7.19%	10.04%	12.39%
IDACORP, Inc.	IDA	$2.36	$86.00	2.74%	2.79%	3.50%	3.10%	3.90%	3.50%	5.89%	6.29%	6.70%
OGE Energy Corporation	OGE	$1.33	$31.89	4.17%	4.27%	2.50%	5.80%	6.00%	4.77%	6.72%	9.04%	10.30%
Pinnacle West Capital Corporation	PNW	$2.78	$79.28	3.51%	3.57%	5.00%	3.63%	3.00%	3.88%	6.56%	7.45%	8.59%
PNM Resources, Inc.	PNM	$1.06	$37.45	2.83%	2.91%	7.50%	4.30%	5.40%	5.73%	7.19%	8.64%	10.44%
Portland General Electric Company	POR	$1.36	$41.35	3.29%	3.34%	2.90%	2.65%	2.90%	2.82%	5.98%	6.15%	6.24%
PPL Corporation	PPL	$1.64	$29.54	5.55%	5.72%	6.00%	n/a	6.00%	6.00%	11.72%	11.72%	11.72%
Southern Company	SO	$2.32	$44.95	5.16%	5.26%	4.50%	2.71%	4.50%	3.90%	7.94%	9.17%	9.78%
MEAN				3.67%	3.77%	4.76%	4.82%	5.12%	4.98%	7.85%	8.75%	9.51%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-day average as of April 30, 2018
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7])) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7])) + Maximum ([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Mean Low ROE	Overall Mean ROE	Mean High ROE
ALLETE, Inc.	ALE	$2.24	$74.65	3.00%	3.09%	4.50%	6.00%	6.60%	5.70%	7.57%	8.79%	9.70%
Alliant Energy Corporation	LNT	$1.34	$41.72	3.21%	3.31%	6.50%	5.80%	5.60%	5.97%	8.90%	9.27%	9.82%
Ameren Corporation	AEE	$1.83	$58.45	3.13%	3.24%	7.50%	n/a	6.80%	7.15%	10.04%	10.39%	10.75%
American Electric Power Company, Inc.	AEP	$2.48	$71.07	3.49%	3.58%	4.50%	5.74%	5.40%	5.21%	8.07%	8.79%	9.33%
Duke Energy Corporation	DUK	$3.56	$82.68	4.31%	4.39%	3.70%	4.25%	3.90%	3.95%	8.09%	8.34%	8.65%
El Paso Electric Company	EE	$1.34	$53.95	2.48%	2.54%	4.50%	5.20%	4.90%	4.87%	7.04%	7.41%	7.75%
Hawaiian Electric Industries, Inc.	HE	$1.24	$34.66	3.58%	3.69%	3.50%	8.60%	6.80%	6.30%	7.14%	9.99%	12.33%
IDACORP, Inc.	IDA	$2.36	$88.93	2.65%	2.70%	3.50%	3.10%	3.90%	3.50%	5.79%	6.20%	6.61%
OGE Energy Corporation	OGE	$1.33	$33.84	3.93%	4.02%	2.50%	5.80%	6.00%	4.77%	6.48%	8.79%	10.05%
Pinnacle West Capital Corporation	PNW	$2.78	$83.99	3.31%	3.37%	5.00%	3.63%	3.00%	3.88%	6.36%	7.25%	8.39%
PNM Resources, Inc.	PNM	$1.06	$40.08	2.64%	2.72%	7.50%	4.30%	5.40%	5.73%	7.00%	8.45%	10.24%
Portland General Electric Company	POR	$1.36	$44.31	3.07%	3.11%	2.90%	2.65%	2.90%	2.82%	5.76%	5.93%	6.01%
PPL Corporation	PPL	$1.64	$33.54	4.89%	5.04%	6.00%	n/a	6.00%	6.00%	11.04%	11.04%	11.04%
Southern Company	SO	$2.32	$47.66	4.87%	4.96%	4.50%	2.71%	4.50%	3.90%	7.64%	8.87%	9.48%
MEAN				3.47%	3.56%	4.76%	4.82%	5.12%	4.98%	7.64%	8.54%	9.30%

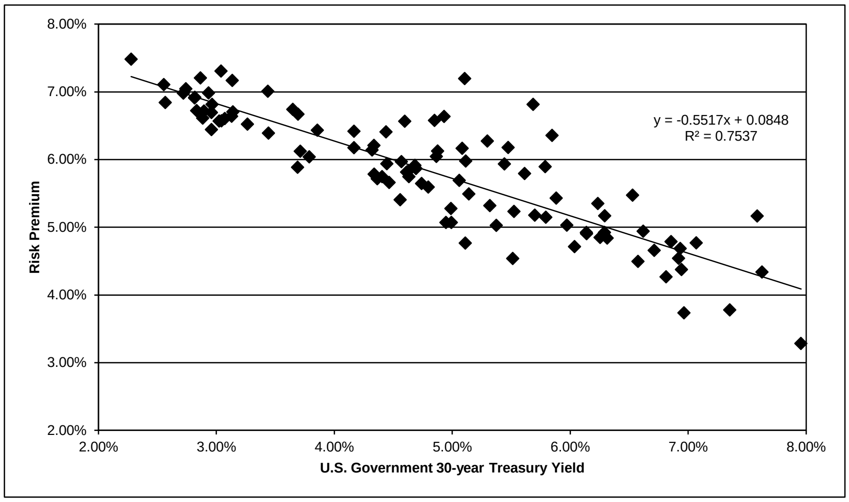
Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of April 30, 2018
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 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%
2017.4	9.74%	2.82%	6.92%
2018.1	9.59%	3.02%	6.57%
2018.2	9.68%	3.07%	6.60%
AVERAGE	10.63%	4.81%	5.83%
MEDIAN	10.54%	4.82%	5.90%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.868169
R Square	0.753717
Adjusted R Square	0.751254
Standard Error	0.004480
Observations	102

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.006141	0.006141	306.037454	0.000000
Residual	100	0.002007	0.000020		
Total	101	0.008148			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0848	0.001579	53.69	0.000000	0.081667	0.087934	0.081667	0.087934
U.S. Govt. 30-year Treasury	(0.5517)	0.031536	(17.49)	0.000000	(0.614264)	(0.489129)	(0.614264)	(0.489129)

	[7]	[8]	[9]
	U.S. Govt. 30-year Treasury	Risk Premium	ROE
Current 30-Day Average [4]	3.07%	6.79%	9.86%
Blue Chip Consensus Forecast (Q3 2018-Q3 2019) [5]	3.58%	6.50%	10.08%
Blue Chip Consensus Forecast (2019-2023) [6]	4.10%	6.22%	10.32%
AVERAGE			10.09%

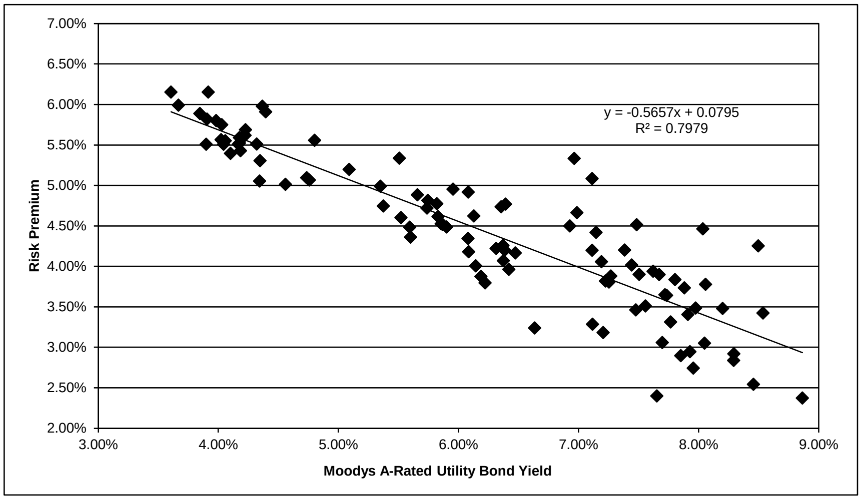
Notes:
[1] Source: Regulatory Research Associates, accessed May 10, 2018
[2] Source: Bloomberg Professional, quarterly bond yields are an average of the trading days in each quarter
[3] Equals Column [1] − Column [2]
[4] Source: Bloomberg Professional, equals 30-day average as of April 30, 2018
[5] Source: Blue Chip Financial Forecasts, Vol. 37, No. 5, May 1, 2018, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 36, No. 12, December 1, 2017, at 14
[7] *See notes [4], [5] & [6]*
[8] Equals 0.084800 + (-0.551697 x Column [7])
[9] Equals Column [7] + Column [8]

UTILITY BOND YIELD PLUS RISK PREMIUM

	[1] Average Authorized Electric ROE	[2] Moodys A-Rated Utility Bond	[3] 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%
2017.4	9.74%	3.85%	5.89%
2018.1	9.59%	4.02%	5.57%
2018.2	9.68%	4.17%	5.51%
AVERAGE	10.63%	6.19%	4.45%
MEDIAN	10.54%	6.27%	4.49%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.893254
R Square	0.797904
Adjusted R Square	0.795883
Standard Error	0.004269
Observations	102

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.007195	0.007195	394.813206	0.000000
Residual	100	0.001822	0.000018		
Total	101	0.009017			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0795	0.001811	43.89	0.000000	0.075892	0.083079	0.075892	0.083079
Moodys A-Rated Utility Bond	(0.5657)	0.028472	(19.87)	0.000000	(0.622215)	(0.509241)	(0.622215)	(0.509241)

	[7]	[8]	[9]
	Moodys A-Rated Utility Bond	Risk Premium	ROE
Current 30-Day Average [4]	4.16%	5.60%	9.75%
Near-Term Consensus Forecast (Q3 2018-Q3 2019) [5]	4.80%	5.23%	10.03%
Long-Term Consensus Forecast (2019-2023) [6]	5.32%	4.94%	10.26%
AVERAGE			10.02%

Notes:

[1] Source: Regulatory Research Associates, accessed May 10, 2018
[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 April 30, 2018
[5] Equals Blue Chip Financial Forecasts near-term 30-year Treasury bond yield (Q3 2018-Q3 2019 Average: 3.58%) plus average daily spread between Treasury and utility bond yields from January 1, 2015 through April 30, 2018 (1.22%)
[6] Equals Blue Chip Financial Forecasts long-term 30-year Treasury bond yield (2019 - 2023 Forecast: 4.10%) plus average daily spread between Treasury and utility bond yields from January 1, 2015 through April 30, 2018 (1.22%)
[7] *See notes [4], [5] & [6]*
[8] Equals 0.079486 + (-0.565728 x Column [7])
[9] Equals Column [7] + Column [8]

BETA
AS OF APRIL 30, 2018

		[1]	[2]
		Bloomberg	Value Line
ALLETE, Inc.	ALE	0.616	0.750
Alliant Energy Corporation	LNT	0.548	0.700
Ameren Corporation	AEE	0.495	0.650
American Electric Power Company, Inc.	AEP	0.582	0.650
Duke Energy Corporation	DUK	0.547	0.600
El Paso Electric Company	EE	0.625	0.750
Hawaiian Electric Industries, Inc.	HE	0.537	0.650
IDACORP, Inc.	IDA	0.625	0.700
OGE Energy Corporation	OGE	0.653	0.950
Pinnacle West Capital Corporation	PNW	0.578	0.650
PNM Resources, Inc.	PNM	0.676	0.700
Portland General Electric Company	POR	0.541	0.650
PPL Corporation	PPL	0.679	0.750
Southern Company	SO	0.414	0.550
Average		0.580	0.693

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		1.97%	
[2] Estimated Weighted Average Long-Term Growth Rate		12.98%	
[3] S&P 500 Estimated Required Market Return		15.08%	
[4] Risk-Free Rate	3.07%	3.58%	4.10%
[5] Implied Market Risk Premium	12.01%	11.50%	10.98%

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%	3.78%	0.01%	7.73%	0.01%
American Express Co	AXP	0.36%	1.42%	0.01%	17.30%	0.06%
Verizon Communications Inc	VZ	0.87%	4.78%	0.04%	2.36%	0.02%
Broadcom Inc	AVGO	0.40%	3.05%	0.01%	12.78%	0.05%
Boeing Co/The	BA	0.83%	2.05%	0.02%	15.20%	0.13%
Caterpillar Inc	CAT	0.37%	2.16%	0.01%	21.78%	0.08%
JPMorgan Chase & Co	JPM	1.59%	2.06%	0.03%	9.80%	0.16%
Chevron Corp	CVX	1.02%	3.58%	0.04%	26.79%	0.27%
Coca-Cola Co/The	KO	0.79%	3.61%	0.03%	8.42%	0.07%
AbbVie Inc	ABBV	0.66%	3.98%	0.03%	13.63%	0.09%
Walt Disney Co/The	DIS	0.65%	1.67%	0.01%	10.12%	0.07%
Extra Space Storage Inc	EXR	0.05%	3.48%	0.00%	5.85%	0.00%
Exxon Mobil Corp	XOM	1.41%	4.22%	0.06%	12.40%	0.17%
Phillips 66	PSX	0.22%	2.52%	0.01%	5.05%	0.01%
General Electric Co	GE	0.52%	3.41%	0.02%	4.03%	0.02%
HP Inc	HPQ	0.15%	2.59%	0.00%	7.19%	0.01%
Home Depot Inc/The	HD	0.91%	2.23%	0.02%	14.58%	0.13%
International Business Machines Corp	IBM	0.57%	4.33%	0.02%	1.97%	0.01%
Concho Resources Inc	CXO	0.10%	n/a	n/a	35.10%	0.04%
Johnson & Johnson	JNJ	1.45%	2.85%	0.04%	7.46%	0.11%
McDonald's Corp	MCD	0.56%	2.41%	0.01%	8.74%	0.05%
Merck & Co Inc	MRK	0.68%	3.26%	0.02%	5.78%	0.04%
3M Co	MMM	0.49%	2.80%	0.01%	8.33%	0.04%
American Water Works Co Inc	AWK	0.07%	2.10%	0.00%	7.92%	0.01%
Bank of America Corp	BAC	1.30%	1.60%	0.02%	13.40%	0.17%
Brighthouse Financial Inc	BHF	0.03%	n/a	n/a	8.00%	0.00%
Baker Hughes a GE Co	BHGE	0.06%	1.99%	0.00%	64.68%	0.04%
Pfizer Inc	PFE	0.93%	3.71%	0.03%	6.98%	0.07%
Procter & Gamble Co/The	PG	0.78%	3.97%	0.03%	7.45%	0.06%
AT&T Inc	T	0.86%	6.12%	0.05%	-1.60%	-0.01%
Travelers Cos Inc/The	TRV	0.15%	2.34%	0.00%	20.65%	0.03%
United Technologies Corp	UTX	0.41%	2.33%	0.01%	10.59%	0.04%
Analog Devices Inc	ADI	0.14%	2.20%	0.00%	9.68%	0.01%
Walmart Inc	WMT	1.12%	2.35%	0.03%	5.95%	0.07%
Cisco Systems Inc	CSCO	0.91%	2.98%	0.03%	6.24%	0.06%
Intel Corp	INTC	1.03%	2.32%	0.02%	8.98%	0.09%
General Motors Co	GM	0.22%	4.14%	0.01%	11.05%	0.02%
Microsoft Corp	MSFT	3.07%	1.80%	0.06%	11.35%	0.35%
Dollar General Corp	DG	0.11%	1.20%	0.00%	15.43%	0.02%
Kinder Morgan Inc/DE	KMI	0.15%	5.06%	0.01%	13.75%	0.02%
Citigroup Inc	C	0.74%	1.87%	0.01%	13.86%	0.10%
American International Group Inc	AIG	0.22%	2.29%	0.00%	11.00%	0.02%
Honeywell International Inc	HON	0.46%	2.06%	0.01%	10.33%	0.05%
Altria Group Inc	MO	0.45%	4.99%	0.02%	4.87%	0.02%
HCA Healthcare Inc	HCA	0.14%	1.46%	0.00%	12.64%	0.02%
Under Armour Inc	UAA	0.01%	n/a	n/a	27.89%	0.00%
International Paper Co	IP	0.09%	3.69%	0.00%	7.10%	0.01%
Hewlett Packard Enterprise Co	HPE	0.11%	2.64%	0.00%	5.12%	0.01%
Abbott Laboratories	ABT	0.43%	1.93%	0.01%	12.67%	0.05%
Aflac Inc	AFL	0.15%	2.28%	0.00%	6.52%	0.01%
Air Products & Chemicals Inc	APD	0.15%	2.71%	0.00%	13.58%	0.02%
Royal Caribbean Cruises Ltd	RCL	0.10%	2.22%	0.00%	15.45%	0.02%
American Electric Power Co Inc	AEP	0.15%	3.54%	0.01%	5.61%	0.01%
Hess Corp	HES	0.07%	1.75%	0.00%	-8.91%	-0.01%
Anadarko Petroleum Corp	APC	0.15%	1.49%	0.00%	1.27%	0.00%
Aon PLC	AON	0.15%	1.12%	0.00%	10.29%	0.02%
Apache Corp	APA	0.07%	2.44%	0.00%	-19.09%	-0.01%
Archer-Daniels-Midland Co	ADM	0.11%	2.95%	0.00%	7.50%	0.01%
Automatic Data Processing Inc	ADP	0.22%	2.34%	0.01%	13.63%	0.03%
Verisk Analytics Inc	VRSK	0.08%	n/a	n/a	13.16%	0.01%
AutoZone Inc	AZO	0.07%	n/a	n/a	14.83%	0.01%
Avery Dennison Corp	AVY	0.04%	1.98%	0.00%	6.20%	0.00%
MSCI Inc	MSCI	0.06%	1.01%	0.00%	12.90%	0.01%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield		1.97%	
[2] Estimated Weighted Average Long-Term Growth Rate		12.98%	
[3] S&P 500 Estimated Required Market Return		15.08%	
[4] Risk-Free Rate	3.07%	3.58%	4.10%
[5] Implied Market Risk Premium	12.01%	11.50%	10.98%

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%	1.00%	0.00%	5.40%	0.00%
Bank of New York Mellon Corp/The	BK	0.24%	1.76%	0.00%	8.10%	0.02%
Baxter International Inc	BAX	0.16%	0.92%	0.00%	12.90%	0.02%
Becton Dickinson and Co	BDX	0.26%	1.29%	0.00%	13.50%	0.04%
Berkshire Hathaway Inc	BRK/B	1.11%	n/a	n/a	6.70%	0.07%
Best Buy Co Inc	BBY	0.09%	2.35%	0.00%	9.22%	0.01%
H&R Block Inc	HRB	0.02%	3.47%	0.00%	11.00%	0.00%
Boston Scientific Corp	BSX	0.17%	n/a	n/a	21.44%	0.04%
Bristol-Myers Squibb Co	BMY	0.36%	3.07%	0.01%	9.00%	0.03%
Fortune Brands Home & Security Inc	FBHS	0.03%	1.46%	0.00%	12.68%	0.00%
Brown-Forman Corp	BF/B	0.07%	1.13%	0.00%	13.83%	0.01%
Cabot Oil & Gas Corp	COG	0.05%	1.00%	0.00%	40.49%	0.02%
Campbell Soup Co	CPB	0.05%	3.43%	0.00%	5.57%	0.00%
Kansas City Southern	KSU	0.05%	1.35%	0.00%	13.00%	0.01%
Advanced Micro Devices Inc	AMD	0.05%	n/a	n/a	23.60%	0.01%
Hilton Worldwide Holdings Inc	HLT	0.10%	0.76%	0.00%	6.15%	0.01%
Carnival Corp	CCL	0.14%	3.17%	0.00%	14.20%	0.02%
Qorvo Inc	QRVO	0.04%	n/a	n/a	12.02%	0.00%
CenturyLink Inc	CTL	0.09%	11.63%	0.01%	-15.40%	-0.01%
Cigna Corp	CI	0.18%	0.02%	0.00%	12.16%	0.02%
UDR Inc	UDR	0.04%	3.57%	0.00%	5.66%	0.00%
Clorox Co/The	CLX	0.06%	3.28%	0.00%	8.34%	0.01%
CMS Energy Corp	CMS	0.06%	3.03%	0.00%	6.29%	0.00%
Colgate-Palmolive Co	CL	0.24%	2.58%	0.01%	8.27%	0.02%
Comerica Inc	CMA	0.07%	1.44%	0.00%	23.03%	0.02%
IPG Photonics Corp	IPGP	0.05%	n/a	n/a	n/a	n/a
CA Inc	CA	0.06%	2.93%	0.00%	2.80%	0.00%
Conagra Brands Inc	CAG	0.06%	2.29%	0.00%	10.35%	0.01%
Consolidated Edison Inc	ED	0.11%	3.57%	0.00%	4.35%	0.00%
SL Green Realty Corp	SLG	0.04%	3.33%	0.00%	4.25%	0.00%
Corning Inc	GLW	0.10%	2.66%	0.00%	7.43%	0.01%
Cummins Inc	CMI	0.11%	2.70%	0.00%	10.24%	0.01%
Danaher Corp	DHR	0.30%	0.64%	0.00%	10.23%	0.03%
Target Corp	TGT	0.17%	3.42%	0.01%	4.48%	0.01%
Deere & Co	DE	0.19%	1.77%	0.00%	7.67%	0.01%
Dominion Energy Inc	D	0.19%	5.02%	0.01%	5.55%	0.01%
Dover Corp	DOV	0.06%	2.03%	0.00%	13.50%	0.01%
Cboe Global Markets Inc	CBOE	0.05%	1.01%	0.00%	21.45%	0.01%
Duke Energy Corp	DUK	0.24%	4.44%	0.01%	4.26%	0.01%
Eaton Corp PLC	ETN	0.14%	3.52%	0.00%	9.08%	0.01%
Ecolab Inc	ECL	0.18%	1.13%	0.00%	13.30%	0.02%
PerkinElmer Inc	PKI	0.03%	0.38%	0.00%	15.34%	0.01%
Emerson Electric Co	EMR	0.18%	2.92%	0.01%	11.77%	0.02%
EOG Resources Inc	EOG	0.29%	0.63%	0.00%	8.16%	0.02%
Entergy Corp	ETR	0.06%	4.36%	0.00%	0.91%	0.00%
Equifax Inc	EFX	0.06%	1.39%	0.00%	8.16%	0.00%
EQT Corp	EQT	0.06%	0.24%	0.00%	17.50%	0.01%
IQVIA Holdings Inc	IQV	0.09%	n/a	n/a	14.82%	0.01%
XL Group Ltd	XL	0.06%	1.58%	0.00%	9.00%	0.01%
Gartner Inc	IT	0.05%	n/a	n/a	15.00%	0.01%
FedEx Corp	FDX	0.28%	0.81%	0.00%	14.60%	0.04%
Macy's Inc	M	0.04%	4.86%	0.00%	-0.07%	0.00%
FMC Corp	FMC	0.05%	0.83%	0.00%	13.87%	0.01%
Ford Motor Co	F	0.19%	5.34%	0.01%	-7.42%	-0.01%
NextEra Energy Inc	NEE	0.33%	2.71%	0.01%	8.57%	0.03%
Franklin Resources Inc	BEN	0.08%	2.73%	0.00%	10.00%	0.01%
Freeport-McMoRan Inc	FCX	0.09%	1.31%	0.00%	-1.41%	0.00%
Gap Inc/The	GPS	0.05%	3.32%	0.00%	8.80%	0.00%
General Dynamics Corp	GD	0.26%	1.85%	0.00%	11.45%	0.03%
General Mills Inc	GIS	0.11%	4.48%	0.00%	7.33%	0.01%
Genuine Parts Co	GPC	0.06%	3.26%	0.00%	-2.49%	0.00%
WW Grainger Inc	GWW	0.07%	1.93%	0.00%	14.70%	0.01%
Halliburton Co	HAL	0.20%	1.36%	0.00%	68.17%	0.14%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield		1.97%	
[2] Estimated Weighted Average Long-Term Growth Rate		12.98%	
[3] S&P 500 Estimated Required Market Return		15.08%	
[4] Risk-Free Rate	3.07%	3.58%	4.10%
[5] Implied Market Risk Premium	12.01%	11.50%	10.98%

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	0.03%	3.60%	0.00%	8.90%	0.00%
Harris Corp	HRS	0.08%	1.46%	0.00%	n/a	n/a
HCP Inc	HCP	0.05%	6.34%	0.00%	-0.23%	0.00%
Helmerich & Payne Inc	HP	0.03%	4.03%	0.00%	152.22%	0.05%
Fortive Corp	FTV	0.10%	0.40%	0.00%	13.04%	0.01%
Hershey Co/The	HSY	0.06%	2.85%	0.00%	8.10%	0.00%
Synchrony Financial	SYF	0.11%	1.81%	0.00%	10.60%	0.01%
Hormel Foods Corp	HRL	0.08%	2.07%	0.00%	8.20%	0.01%
Arthur J Gallagher & Co	AJG	0.05%	2.34%	0.00%	11.81%	0.01%
Mondelez International Inc	MDLZ	0.25%	2.23%	0.01%	11.48%	0.03%
CenterPoint Energy Inc	CNP	0.05%	4.38%	0.00%	5.67%	0.00%
Humana Inc	HUM	0.17%	0.68%	0.00%	14.08%	0.02%
Willis Towers Watson PLC	WLTW	0.08%	1.62%	0.00%	10.00%	0.01%
Illinois Tool Works Inc	ITW	0.21%	2.20%	0.00%	9.67%	0.02%
Ingersoll-Rand PLC	IR	0.09%	2.15%	0.00%	10.92%	0.01%
Foot Locker Inc	FL	0.02%	3.20%	0.00%	5.42%	0.00%
Interpublic Group of Cos Inc/The	IPG	0.04%	3.56%	0.00%	5.30%	0.00%
International Flavors & Fragrances Inc	IFF	0.05%	1.95%	0.00%	8.20%	0.00%
Jacobs Engineering Group Inc	JEC	0.04%	1.03%	0.00%	15.97%	0.01%
Hanesbrands Inc	HBI	0.03%	3.25%	0.00%	7.19%	0.00%
Kellogg Co	K	0.09%	3.67%	0.00%	7.67%	0.01%
Perrigo Co PLC	PRGO	0.05%	0.97%	0.00%	6.62%	0.00%
Kimberly-Clark Corp	KMB	0.15%	3.86%	0.01%	14.24%	0.02%
Kimco Realty Corp	KIM	0.03%	7.72%	0.00%	3.62%	0.00%
Kohl's Corp	KSS	0.04%	3.93%	0.00%	6.40%	0.00%
Oracle Corp	ORCL	0.80%	1.66%	0.01%	8.71%	0.07%
Kroger Co/The	KR	0.09%	1.98%	0.00%	5.57%	0.01%
Leggett & Platt Inc	LEG	0.02%	3.55%	0.00%	10.50%	0.00%
Lennar Corp	LEN	0.07%	0.30%	0.00%	20.99%	0.01%
Leucadia National Corp	LUK	0.04%	1.66%	0.00%	18.00%	0.01%
Eli Lilly & Co	LLY	0.38%	2.78%	0.01%	10.57%	0.04%
L Brands Inc	LB	0.04%	6.87%	0.00%	11.66%	0.00%
Charter Communications Inc	CHTR	0.28%	n/a	n/a	26.99%	0.07%
Lincoln National Corp	LNC	0.07%	1.87%	0.00%	8.00%	0.01%
Loews Corp	L	0.07%	0.48%	0.00%	n/a	n/a
Lowe's Cos Inc	LOW	0.29%	1.99%	0.01%	16.34%	0.05%
Host Hotels & Resorts Inc	HST	0.06%	4.09%	0.00%	4.13%	0.00%
Marsh & McLennan Cos Inc	MMC	0.18%	1.84%	0.00%	13.04%	0.02%
Masco Corp	MAS	0.05%	1.11%	0.00%	15.84%	0.01%
Mattel Inc	MAT	0.02%	n/a	n/a	9.73%	0.00%
S&P Global Inc	SPGI	0.20%	1.06%	0.00%	11.70%	0.02%
Medtronic PLC	MDT	0.46%	2.30%	0.01%	6.70%	0.03%
CVS Health Corp	CVS	0.30%	2.86%	0.01%	11.16%	0.03%
DowDuPont Inc	DWDP	0.63%	2.40%	0.02%	7.37%	0.05%
Micron Technology Inc	MU	0.23%	n/a	n/a	0.45%	0.00%
Motorola Solutions Inc	MSI	0.08%	1.89%	0.00%	4.07%	0.00%
Mylan NV	MYL	0.09%	n/a	n/a	5.76%	0.00%
Laboratory Corp of America Holdings	LH	0.07%	n/a	n/a	9.40%	0.01%
Newell Brands Inc	NWL	0.06%	3.33%	0.00%	5.48%	0.00%
Newmont Mining Corp	NEM	0.09%	1.43%	0.00%	-3.00%	0.00%
Twenty-First Century Fox Inc	FOXA	0.16%	0.98%	0.00%	10.50%	0.02%
NIKE Inc	NKE	0.38%	1.17%	0.00%	11.72%	0.04%
NiSource Inc	NI	0.04%	3.20%	0.00%	5.61%	0.00%
Noble Energy Inc	NBL	0.07%	1.30%	0.00%	9.99%	0.01%
Norfolk Southern Corp	NSC	0.17%	2.01%	0.00%	14.33%	0.02%
Principal Financial Group Inc	PFG	0.07%	3.51%	0.00%	9.39%	0.01%
Eversource Energy	ES	0.08%	3.35%	0.00%	5.93%	0.00%
Northrop Grumman Corp	NOC	0.24%	1.37%	0.00%	14.80%	0.04%
Wells Fargo & Co	WFC	1.08%	3.00%	0.03%	10.66%	0.12%
Nucor Corp	NUE	0.08%	2.47%	0.00%	5.55%	0.00%
PVH Corp	PVH	0.05%	0.09%	0.00%	10.87%	0.01%
Occidental Petroleum Corp	OXY	0.25%	3.99%	0.01%	8.05%	0.02%
Omnicom Group Inc	OMC	0.07%	3.26%	0.00%	5.70%	0.00%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield		1.97%	
[2] Estimated Weighted Average Long-Term Growth Rate		12.98%	
[3] S&P 500 Estimated Required Market Return		15.08%	
[4] Risk-Free Rate	3.07%	3.58%	4.10%
[5] Implied Market Risk Premium	12.01%	11.50%	10.98%

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
ONEOK Inc	OKE	0.11%	5.28%	0.01%	26.19%	0.03%
Raymond James Financial Inc	RJF	0.06%	1.11%	0.00%	17.00%	0.01%
PG&E Corp	PCG	0.10%	n/a	n/a	5.25%	0.01%
Parker-Hannifin Corp	PH	0.09%	1.85%	0.00%	10.12%	0.01%
PPL Corp	PPL	0.09%	5.64%	0.00%	5.47%	0.00%
Exelon Corp	EXC	0.16%	3.48%	0.01%	4.63%	0.01%
ConocoPhillips	COP	0.33%	1.74%	0.01%	6.00%	0.02%
PulteGroup Inc	PHM	0.04%	1.19%	0.00%	21.25%	0.01%
Pinnacle West Capital Corp	PNW	0.04%	3.45%	0.00%	3.22%	0.00%
PNC Financial Services Group Inc/The	PNC	0.29%	2.06%	0.01%	10.21%	0.03%
PPG Industries Inc	PPG	0.11%	1.70%	0.00%	8.73%	0.01%
Praxair Inc	PX	0.19%	2.16%	0.00%	10.50%	0.02%
Progressive Corp/The	PGR	0.15%	1.87%	0.00%	9.33%	0.01%
Public Service Enterprise Group Inc	PEG	0.11%	3.45%	0.00%	5.68%	0.01%
Raytheon Co	RTN	0.25%	1.69%	0.00%	14.97%	0.04%
Robert Half International Inc	RHI	0.03%	1.84%	0.00%	n/a	n/a
SCANA Corp	SCG	0.02%	6.66%	0.00%	-2.10%	0.00%
Edison International	EIX	0.09%	3.69%	0.00%	4.93%	0.00%
Schlumberger Ltd	SLB	0.41%	2.92%	0.01%	38.95%	0.16%
Charles Schwab Corp/The	SCHW	0.32%	0.72%	0.00%	21.02%	0.07%
Sherwin-Williams Co/The	SHW	0.15%	0.94%	0.00%	11.26%	0.02%
JM Smucker Co/The	SJM	0.06%	2.73%	0.00%	6.70%	0.00%
Snap-on Inc	SNA	0.04%	2.26%	0.00%	9.70%	0.00%
AMETEK Inc	AME	0.07%	0.80%	0.00%	10.38%	0.01%
Southern Co/The	SO	0.20%	5.20%	0.01%	4.73%	0.01%
BB&T Corp	BBT	0.18%	2.84%	0.01%	14.75%	0.03%
Southwest Airlines Co	LUV	0.13%	0.95%	0.00%	12.11%	0.02%
Stanley Black & Decker Inc	SWK	0.09%	1.78%	0.00%	11.50%	0.01%
Public Storage	PSA	0.15%	3.96%	0.01%	5.15%	0.01%
SunTrust Banks Inc	STI	0.13%	2.40%	0.00%	13.17%	0.02%
Sysco Corp	SYY	0.14%	2.30%	0.00%	11.62%	0.02%
Andeavor	ANDV	0.09%	1.71%	0.00%	7.65%	0.01%
Texas Instruments Inc	TXN	0.43%	2.45%	0.01%	11.90%	0.05%
Textron Inc	TXT	0.07%	0.13%	0.00%	13.51%	0.01%
Thermo Fisher Scientific Inc	TMO	0.36%	0.32%	0.00%	10.93%	0.04%
Tiffany & Co	TIF	0.05%	1.95%	0.00%	10.28%	0.01%
TJX Cos Inc/The	TJX	0.23%	1.84%	0.00%	12.53%	0.03%
Torchmark Corp	TMK	0.04%	0.74%	0.00%	10.45%	0.00%
Total System Services Inc	TSS	0.07%	0.62%	0.00%	14.57%	0.01%
Johnson Controls International plc	JCI	0.13%	3.07%	0.00%	10.40%	0.01%
Ulta Beauty Inc	ULTA	0.06%	n/a	n/a	18.60%	0.01%
Union Pacific Corp	UNP	0.44%	2.19%	0.01%	14.45%	0.06%
UnitedHealth Group Inc	UNH	0.97%	1.27%	0.01%	12.99%	0.13%
Unum Group	UNM	0.05%	1.90%	0.00%	7.00%	0.00%
Marathon Oil Corp	MRO	0.07%	1.10%	0.00%	5.00%	0.00%
Varian Medical Systems Inc	VAR	0.05%	n/a	n/a	11.25%	0.01%
Ventas Inc	VTR	0.08%	6.15%	0.00%	1.81%	0.00%
VF Corp	VFC	0.14%	2.28%	0.00%	7.00%	0.01%
Vornado Realty Trust	VNO	0.06%	3.70%	0.00%	6.37%	0.00%
Vulcan Materials Co	VMC	0.06%	1.00%	0.00%	20.49%	0.01%
Weyerhaeuser Co	WY	0.12%	3.48%	0.00%	9.25%	0.01%
Whirlpool Corp	WHR	0.05%	2.97%	0.00%	9.98%	0.00%
Williams Cos Inc/The	WMB	0.09%	5.29%	0.00%	-13.30%	-0.01%
WEC Energy Group Inc	WEC	0.09%	3.44%	0.00%	3.43%	0.00%
Xerox Corp	XRX	0.03%	3.18%	0.00%	1.00%	0.00%
Adobe Systems Inc	ADBE	0.47%	n/a	n/a	18.66%	0.09%
AES Corp/VA	AES	0.03%	4.25%	0.00%	7.98%	0.00%
Amgen Inc	AMGN	0.49%	3.03%	0.01%	5.11%	0.03%
Apple Inc	AAPL	3.59%	1.52%	0.05%	12.26%	0.44%
Autodesk Inc	ADSK	0.12%	n/a	n/a	48.90%	0.06%
Cintas Corp	CTAS	0.08%	0.95%	0.00%	11.60%	0.01%
Comcast Corp	CMCSA	0.62%	2.42%	0.01%	16.75%	0.10%
Molson Coors Brewing Co	TAP	0.06%	2.30%	0.00%	6.16%	0.00%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield		1.97%	
[2] Estimated Weighted Average Long-Term Growth Rate		12.98%	
[3] S&P 500 Estimated Required Market Return		15.08%	
[4] Risk-Free Rate	3.07%	3.58%	4.10%
[5] Implied Market Risk Premium	12.01%	11.50%	10.98%

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%	2.95%	0.00%	11.16%	0.01%
Marriott International Inc/MD	MAR	0.21%	0.97%	0.00%	15.03%	0.03%
McCormick & Co Inc/MD	MKC	0.05%	1.97%	0.00%	8.30%	0.00%
Nordstrom Inc	JWN	0.04%	2.93%	0.00%	8.05%	0.00%
PACCAR Inc	PCAR	0.10%	1.57%	0.00%	7.70%	0.01%
Costco Wholesale Corp	COST	0.37%	1.16%	0.00%	11.47%	0.04%
Stryker Corp	SYK	0.27%	1.11%	0.00%	8.89%	0.02%
Tyson Foods Inc	TSN	0.09%	1.71%	0.00%	8.00%	0.01%
Applied Materials Inc	AMAT	0.22%	1.61%	0.00%	15.58%	0.03%
Time Warner Inc	TWX	0.32%	1.70%	0.01%	5.10%	0.02%
American Airlines Group Inc	AAL	0.09%	0.93%	0.00%	14.65%	0.01%
Cardinal Health Inc	CAH	0.09%	2.88%	0.00%	11.77%	0.01%
Celgene Corp	CELG	0.27%	n/a	n/a	17.94%	0.05%
Cerner Corp	CERN	0.08%	n/a	n/a	12.19%	0.01%
Cincinnati Financial Corp	CINF	0.05%	3.01%	0.00%	n/a	n/a
DR Horton Inc	DHI	0.07%	1.13%	0.00%	20.52%	0.01%
Flowserve Corp	FLS	0.02%	1.71%	0.00%	19.47%	0.00%
Electronic Arts Inc	EA	0.15%	n/a	n/a	13.57%	0.02%
Express Scripts Holding Co	ESRX	0.18%	n/a	n/a	8.19%	0.01%
Expeditors International of Washington Inc	EXPD	0.05%	1.32%	0.00%	9.33%	0.00%
Fastenal Co	FAST	0.06%	2.96%	0.00%	17.50%	0.01%
M&T Bank Corp	MTB	0.12%	1.65%	0.00%	12.58%	0.01%
Xcel Energy Inc	XEL	0.10%	3.25%	0.00%	5.88%	0.01%
Fiserv Inc	FISV	0.12%	n/a	n/a	3.30%	0.00%
Fifth Third Bancorp	FITB	0.10%	1.93%	0.00%	5.65%	0.01%
Gilead Sciences Inc	GILD	0.40%	3.16%	0.01%	2.29%	0.01%
Hasbro Inc	HAS	0.05%	2.86%	0.00%	8.17%	0.00%
Huntington Bancshares Inc/OH	HBAN	0.07%	2.95%	0.00%	12.54%	0.01%
Welltower Inc	WELL	0.08%	6.51%	0.01%	5.58%	0.00%
Biogen Inc	BIIB	0.25%	n/a	n/a	5.55%	0.01%
Range Resources Corp	RRC	0.01%	0.58%	0.00%	26.75%	0.00%
Northern Trust Corp	NTRS	0.10%	1.57%	0.00%	13.84%	0.01%
Packaging Corp of America	PKG	0.05%	2.18%	0.00%	8.00%	0.00%
Paychex Inc	PAYX	0.09%	3.70%	0.00%	8.50%	0.01%
People's United Financial Inc	PBCT	0.03%	3.83%	0.00%	2.00%	0.00%
QUALCOMM Inc	QCOM	0.32%	4.86%	0.02%	5.89%	0.02%
Roper Technologies Inc	ROP	0.12%	0.62%	0.00%	10.93%	0.01%
Ross Stores Inc	ROST	0.13%	1.11%	0.00%	13.12%	0.02%
IDEXX Laboratories Inc	IDXX	0.07%	n/a	n/a	16.73%	0.01%
Starbucks Corp	SBUX	0.35%	2.08%	0.01%	15.03%	0.05%
KeyCorp	KEY	0.09%	2.11%	0.00%	16.36%	0.01%
State Street Corp	STT	0.16%	1.68%	0.00%	17.73%	0.03%
Norwegian Cruise Line Holdings Ltd	NCLH	0.05%	n/a	n/a	19.73%	0.01%
US Bancorp	USB	0.36%	2.38%	0.01%	8.03%	0.03%
AO Smith Corp	AOS	0.04%	1.17%	0.00%	11.50%	0.00%
Symantec Corp	SYMC	0.07%	1.08%	0.00%	12.60%	0.01%
T Rowe Price Group Inc	TROW	0.12%	2.46%	0.00%	12.57%	0.01%
Waste Management Inc	WM	0.15%	2.29%	0.00%	12.14%	0.02%
CBS Corp	CBS	0.07%	1.46%	0.00%	13.92%	0.01%
Allergan PLC	AGN	0.23%	1.87%	0.00%	7.65%	0.02%
Constellation Brands Inc	STZ	0.17%	1.27%	0.00%	16.12%	0.03%
Xilinx Inc	XLNX	0.07%	2.24%	0.00%	10.20%	0.01%
DENTSPLY SIRONA Inc	XRAY	0.05%	0.70%	0.00%	9.95%	0.00%
Zions Bancorporation	ZION	0.05%	1.75%	0.00%	10.23%	0.00%
Alaska Air Group Inc	ALK	0.03%	1.97%	0.00%	6.49%	0.00%
Invesco Ltd	IVZ	0.05%	4.14%	0.00%	8.94%	0.00%
Intuit Inc	INTU	0.20%	0.84%	0.00%	16.26%	0.03%
Morgan Stanley	MS	0.39%	1.94%	0.01%	14.35%	0.06%
Microchip Technology Inc	MCHP	0.08%	1.74%	0.00%	14.29%	0.01%
Chubb Ltd	CB	0.27%	2.09%	0.01%	10.93%	0.03%
Hologic Inc	HOLX	0.05%	n/a	n/a	6.81%	0.00%
Citizens Financial Group Inc	CFG	0.09%	2.12%	0.00%	21.07%	0.02%
O'Reilly Automotive Inc	ORLY	0.09%	n/a	n/a	14.40%	0.01%

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
Allstate Corp/The	ALL	0.15%	1.88%	0.00%	6.87%	0.01%
FLIR Systems Inc	FLIR	0.03%	1.20%	0.00%	n/a	n/a
Equity Residential	EQR	0.10%	3.50%	0.00%	6.73%	0.01%
BorgWarner Inc	BWA	0.04%	1.39%	0.00%	4.83%	0.00%
Newfield Exploration Co	NFX	0.03%	n/a	n/a	18.63%	0.00%
Incyte Corp	INCY	0.06%	n/a	n/a	46.97%	0.03%
Simon Property Group Inc	SPG	0.21%	4.99%	0.01%	6.11%	0.01%
Eastman Chemical Co	EMN	0.06%	2.19%	0.00%	7.65%	0.00%
AvalonBay Communities Inc	AVB	0.10%	3.61%	0.00%	6.04%	0.01%
Prudential Financial Inc	PRU	0.19%	3.39%	0.01%	8.50%	0.02%
United Parcel Service Inc	UPS	0.33%	3.21%	0.01%	14.92%	0.05%
Apartment Investment & Management Co	AIV	0.03%	3.74%	0.00%	5.80%	0.00%
Walgreens Boots Alliance Inc	WBA	0.28%	2.41%	0.01%	10.73%	0.03%
McKesson Corp	MCK	0.14%	0.87%	0.00%	8.27%	0.01%
Lockheed Martin Corp	LMT	0.39%	2.49%	0.01%	22.09%	0.09%
AmerisourceBergen Corp	ABC	0.09%	1.68%	0.00%	9.80%	0.01%
Capital One Financial Corp	COF	0.19%	1.77%	0.00%	16.15%	0.03%
Waters Corp	WAT	0.06%	n/a	n/a	8.61%	0.01%
Dollar Tree Inc	DLTR	0.10%	n/a	n/a	13.27%	0.01%
Darden Restaurants Inc	DRI	0.05%	2.71%	0.00%	10.84%	0.01%
NetApp Inc	NTAP	0.08%	2.40%	0.00%	9.83%	0.01%
Citrix Systems Inc	CTXS	0.06%	n/a	n/a	11.00%	0.01%
Goodyear Tire & Rubber Co/The	GT	0.03%	2.23%	0.00%	n/a	n/a
DXC Technology Co	DXC	0.13%	0.70%	0.00%	14.95%	0.02%
DaVita Inc	DVA	0.05%	n/a	n/a	18.33%	0.01%
Hartford Financial Services Group Inc/The	HIG	0.08%	1.86%	0.00%	9.50%	0.01%
Iron Mountain Inc	IRM	0.04%	6.92%	0.00%	9.00%	0.00%
Estee Lauder Cos Inc/The	EL	0.14%	1.03%	0.00%	14.19%	0.02%
Cadence Design Systems Inc	CDNS	0.05%	n/a	n/a	12.00%	0.01%
Stericycle Inc	SRCL	0.02%	n/a	n/a	8.87%	0.00%
Universal Health Services Inc	UHS	0.04%	0.35%	0.00%	9.44%	0.00%
E*TRADE Financial Corp	ETFC	0.07%	n/a	n/a	29.86%	0.02%
Skyworks Solutions Inc	SWKS	0.07%	1.48%	0.00%	9.59%	0.01%
National Oilwell Varco Inc	NOV	0.06%	0.52%	0.00%	48.74%	0.03%
Quest Diagnostics Inc	DGX	0.06%	1.98%	0.00%	9.95%	0.01%
Activision Blizzard Inc	ATVI	0.22%	0.51%	0.00%	14.61%	0.03%
Rockwell Automation Inc	ROK	0.09%	2.24%	0.00%	11.49%	0.01%
Kraft Heinz Co/The	KHC	0.29%	4.43%	0.01%	7.03%	0.02%
American Tower Corp	AMT	0.26%	2.20%	0.01%	17.39%	0.04%
Regeneron Pharmaceuticals Inc	REGN	0.14%	n/a	n/a	14.03%	0.02%
Amazon.com Inc	AMZN	3.25%	n/a	n/a	39.85%	1.29%
Ralph Lauren Corp	RL	0.03%	1.82%	0.00%	5.16%	0.00%
Boston Properties Inc	BXP	0.08%	2.64%	0.00%	6.14%	0.00%
Amphenol Corp	APH	0.11%	1.10%	0.00%	10.94%	0.01%
Arconic Inc	ARNC	0.04%	1.35%	0.00%	15.95%	0.01%
Pioneer Natural Resources Co	PXD	0.15%	0.16%	0.00%	30.50%	0.04%
Valero Energy Corp	VLO	0.20%	2.88%	0.01%	9.79%	0.02%
Synopsys Inc	SNPS	0.05%	n/a	n/a	n/a	n/a
L3 Technologies Inc	LLL	0.07%	1.63%	0.00%	10.72%	0.01%
Western Union Co/The	WU	0.04%	3.85%	0.00%	4.46%	0.00%
CH Robinson Worldwide Inc	CHRW	0.05%	2.00%	0.00%	10.93%	0.01%
Accenture PLC	ACN	0.42%	1.76%	0.01%	11.10%	0.05%
TransDigm Group Inc	TDG	0.07%	n/a	n/a	11.28%	0.01%
Yum! Brands Inc	YUM	0.12%	1.65%	0.00%	12.13%	0.01%
Prologis Inc	PLD	0.15%	2.96%	0.00%	6.53%	0.01%
FirstEnergy Corp	FE	0.07%	4.19%	0.00%	-0.12%	0.00%
VeriSign Inc	VRSN	0.05%	n/a	n/a	9.70%	0.00%
Quanta Services Inc	PWR	0.02%	n/a	n/a	n/a	n/a
Henry Schein Inc	HSIC	0.05%	n/a	n/a	9.14%	0.00%
Ameren Corp	AEE	0.06%	3.12%	0.00%	8.36%	0.01%
ANSYS Inc	ANSS	0.06%	n/a	n/a	12.20%	0.01%
NVIDIA Corp	NVDA	0.58%	0.27%	0.00%	10.28%	0.06%
Sealed Air Corp	SEE	0.03%	1.46%	0.00%	4.25%	0.00%

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STANDARD AND POOR'S 500 INDEX

		[6]	[7]	[8]	[9]	[10]
Name	Ticker	Weight In Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Long-Term Growth Estimate	Cap. Weighted Long-Term Growth
Cognizant Technology Solutions Corp	CTSH	0.20%	0.98%	0.00%	15.00%	0.03%
SVB Financial Group	SIVB	0.07%	n/a	n/a	10.75%	0.01%
Intuitive Surgical Inc	ISRG	0.21%	n/a	n/a	11.75%	0.03%
Aetna Inc	AET	0.25%	1.12%	0.00%	11.21%	0.03%
Affiliated Managers Group Inc	AMG	0.04%	0.73%	0.00%	12.85%	0.00%
Take-Two Interactive Software Inc	TTWO	0.05%	n/a	n/a	10.00%	0.00%
Republic Services Inc	RSG	0.09%	2.13%	0.00%	10.18%	0.01%
eBay Inc	EBAY	0.16%	n/a	n/a	10.19%	0.02%
Goldman Sachs Group Inc/The	GS	0.39%	1.34%	0.01%	16.05%	0.06%
SBA Communications Corp	SBAC	0.08%	n/a	n/a	44.50%	0.04%
Sempra Energy	SRE	0.13%	3.20%	0.00%	16.92%	0.02%
Moody's Corp	MCO	0.13%	1.09%	0.00%	8.00%	0.01%
Booking Holdings Inc	BKNG	0.45%	n/a	n/a	14.07%	0.06%
F5 Networks Inc	FFIV	0.04%	n/a	n/a	10.25%	0.00%
Akamai Technologies Inc	AKAM	0.05%	n/a	n/a	11.50%	0.01%
Devon Energy Corp	DVN	0.08%	0.88%	0.00%	11.01%	0.01%
Alphabet Inc	GOOGL	1.30%	n/a	n/a	18.96%	0.25%
Red Hat Inc	RHT	0.12%	n/a	n/a	17.16%	0.02%
Allegion PLC	ALLE	0.03%	1.09%	0.00%	12.17%	0.00%
Netflix Inc	NFLX	0.58%	n/a	n/a	47.66%	0.28%
Agilent Technologies Inc	A	0.09%	0.91%	0.00%	5.13%	0.00%
Anthem Inc	ANTM	0.26%	1.27%	0.00%	10.09%	0.03%
CME Group Inc	CME	0.23%	1.78%	0.00%	9.00%	0.02%
Juniper Networks Inc	JNPR	0.04%	2.93%	0.00%	6.75%	0.00%
BlackRock Inc	BLK	0.36%	2.21%	0.01%	11.38%	0.04%
DTE Energy Co	DTE	0.08%	3.35%	0.00%	5.30%	0.00%
Nasdaq Inc	NDAQ	0.06%	1.99%	0.00%	10.79%	0.01%
Philip Morris International Inc	PM	0.55%	5.22%	0.03%	11.12%	0.06%
salesforce.com Inc	CRM	0.38%	n/a	n/a	25.55%	0.10%
Huntington Ingalls Industries Inc	HII	0.05%	1.18%	0.00%	27.50%	0.01%
MetLife Inc	MET	0.21%	3.52%	0.01%	12.71%	0.03%
Under Armour Inc	UA	0.01%	n/a	n/a	36.17%	0.01%
Monsanto Co	MON	0.24%	1.72%	0.00%	7.95%	0.02%
Tapestry Inc	TPR	0.07%	2.51%	0.00%	11.61%	0.01%
Fluor Corp	FLR	0.04%	1.42%	0.00%	20.61%	0.01%
CSX Corp	CSX	0.22%	1.48%	0.00%	13.85%	0.03%
Edwards Lifesciences Corp	EW	0.11%	n/a	n/a	15.33%	0.02%
Ameriprise Financial Inc	AMP	0.09%	2.57%	0.00%	10.90%	0.01%
Rockwell Collins Inc	COL	0.09%	1.00%	0.00%	13.00%	0.01%
TechnipFMC PLC	FTI	0.07%	1.58%	0.00%	4.55%	0.00%
Zimmer Biomet Holdings Inc	ZBH	0.10%	0.83%	0.00%	5.74%	0.01%
CBRE Group Inc	CBRE	0.07%	n/a	n/a	10.75%	0.01%
Mastercard Inc	MA	0.79%	0.56%	0.00%	22.97%	0.18%
CarMax Inc	KMX	0.05%	n/a	n/a	14.45%	0.01%
Intercontinental Exchange Inc	ICE	0.18%	1.32%	0.00%	11.34%	0.02%
Fidelity National Information Services Inc	FIS	0.13%	1.35%	0.00%	11.15%	0.01%
Chipotle Mexican Grill Inc	CMG	0.05%	n/a	n/a	18.68%	0.01%
Wynn Resorts Ltd	WYNN	0.09%	1.61%	0.00%	8.40%	0.01%
Assurant Inc	AIZ	0.02%	2.41%	0.00%	n/a	n/a
NRG Energy Inc	NRG	0.04%	0.39%	0.00%	18.17%	0.01%
Monster Beverage Corp	MNST	0.13%	n/a	n/a	18.25%	0.02%
Regions Financial Corp	RF	0.09%	1.93%	0.00%	16.09%	0.01%
Mosaic Co/The	MOS	0.04%	0.37%	0.00%	13.65%	0.01%
Expedia Group Inc	EXPE	0.07%	1.04%	0.00%	16.76%	0.01%
Discovery Inc	DISCA	0.02%	n/a	n/a	6.00%	0.00%
CF Industries Holdings Inc	CF	0.04%	3.09%	0.00%	12.70%	0.00%
Viacom Inc	VIAB	0.05%	2.65%	0.00%	6.99%	0.00%
Wyndham Worldwide Corp	WYN	0.05%	2.31%	0.00%	n/a	n/a
Alphabet Inc	GOOG	1.52%	n/a	n/a	18.96%	0.29%
TE Connectivity Ltd	TEL	0.14%	1.74%	0.00%	10.33%	0.01%
Cooper Cos Inc/The	COO	0.05%	0.03%	0.00%	10.73%	0.01%
Discover Financial Services	DFS	0.11%	1.96%	0.00%	8.89%	0.01%
TripAdvisor Inc	TRIP	0.02%	n/a	n/a	13.84%	0.00%

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STANDARD AND POOR'S 500 INDEX

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Dr Pepper Snapple Group Inc	DPS	0.09%	1.93%	0.00%	7.40%	0.01%
Visa Inc	V	0.97%	0.66%	0.01%	17.35%	0.17%
Mid-America Apartment Communities Inc	MAA	0.04%	4.03%	0.00%	7.00%	0.00%
Xylem Inc/NY	XYL	0.06%	1.15%	0.00%	18.00%	0.01%
Marathon Petroleum Corp	MPC	0.15%	2.46%	0.00%	2.76%	0.00%
Tractor Supply Co	TSCO	0.04%	1.59%	0.00%	13.29%	0.00%
ResMed Inc	RMD	0.06%	1.48%	0.00%	16.10%	0.01%
Mettler-Toledo International Inc	MTD	0.06%	n/a	n/a	14.69%	0.01%
Albemarle Corp	ALB	0.05%	1.38%	0.00%	11.70%	0.01%
Essex Property Trust Inc	ESS	0.07%	3.10%	0.00%	6.25%	0.00%
GGP Inc	GGP	0.08%	4.40%	0.00%	4.13%	0.00%
Realty Income Corp	O	0.06%	5.21%	0.00%	4.33%	0.00%
Seagate Technology PLC	STX	0.07%	4.35%	0.00%	10.85%	0.01%
WestRock Co	WRK	0.06%	2.91%	0.00%	7.07%	0.00%
IHS Markit Ltd	INFO	0.08%	n/a	n/a	12.33%	0.01%
Western Digital Corp	WDC	0.10%	2.54%	0.00%	14.08%	0.01%
PepsiCo Inc	PEP	0.61%	3.19%	0.02%	6.92%	0.04%
Nektar Therapeutics	NKTR	0.06%	n/a	n/a	n/a	n/a
Church & Dwight Co Inc	CHD	0.05%	1.88%	0.00%	10.21%	0.00%
Duke Realty Corp	DRE	0.04%	2.95%	0.00%	-4.00%	0.00%
Federal Realty Investment Trust	FRT	0.04%	3.45%	0.00%	4.39%	0.00%
MGM Resorts International	MGM	0.07%	1.53%	0.00%	7.51%	0.01%
Twenty-First Century Fox Inc	FOX	0.12%	1.00%	0.00%	10.50%	0.01%
Alliant Energy Corp	LNT	0.04%	3.12%	0.00%	5.92%	0.00%
JB Hunt Transport Services Inc	JBHT	0.06%	0.82%	0.00%	13.10%	0.01%
Lam Research Corp	LRCX	0.13%	1.08%	0.00%	6.50%	0.01%
Mohawk Industries Inc	MHK	0.07%	n/a	n/a	8.58%	0.01%
Pentair PLC	PNR	0.03%	3.10%	0.00%	10.34%	0.00%
Vertex Pharmaceuticals Inc	VRTX	0.17%	n/a	n/a	62.33%	0.10%
Facebook Inc	FB	1.76%	n/a	n/a	21.49%	0.38%
United Rentals Inc	URI	0.05%	n/a	n/a	17.76%	0.01%
Alexandria Real Estate Equities Inc	ARE	0.05%	2.89%	0.00%	6.81%	0.00%
United Continental Holdings Inc	UAL	0.08%	n/a	n/a	20.48%	0.02%
Navient Corp	NAVI	0.02%	4.83%	0.00%	-6.00%	0.00%
Delta Air Lines Inc	DAL	0.16%	2.34%	0.00%	17.72%	0.03%
News Corp	NWS	0.01%	1.23%	0.00%	13.33%	0.00%
Centene Corp	CNC	0.08%	n/a	n/a	16.65%	0.01%
Regency Centers Corp	REG	0.04%	3.77%	0.00%	8.58%	0.00%
Macerich Co/The	MAC	0.03%	5.14%	0.00%	5.08%	0.00%
Martin Marietta Materials Inc	MLM	0.05%	0.90%	0.00%	13.69%	0.01%
Envision Healthcare Corp	EVHC	0.02%	n/a	n/a	14.96%	0.00%
PayPal Holdings Inc	PYPL	0.38%	n/a	n/a	18.07%	0.07%
Coty Inc	COTY	0.06%	2.88%	0.00%	16.71%	0.01%
DISH Network Corp	DISH	0.03%	n/a	n/a	-8.23%	0.00%
Alexion Pharmaceuticals Inc	ALXN	0.11%	n/a	n/a	18.87%	0.02%
Everest Re Group Ltd	RE	0.04%	2.23%	0.00%	10.00%	0.00%
News Corp	NWSA	0.03%	1.25%	0.00%	13.33%	0.00%
Global Payments Inc	GPN	0.08%	0.04%	0.00%	22.05%	0.02%
Crown Castle International Corp	CCI	0.18%	4.16%	0.01%	16.53%	0.03%
Aptiv PLC	APTV	0.10%	1.04%	0.00%	11.39%	0.01%
Advance Auto Parts Inc	AAP	0.04%	0.21%	0.00%	16.43%	0.01%
Michael Kors Holdings Ltd	KORS	0.04%	n/a	n/a	6.06%	0.00%
Align Technology Inc	ALGN	0.09%	n/a	n/a	30.55%	0.03%
Illumina Inc	ILMN	0.15%	n/a	n/a	16.76%	0.03%
Acuity Brands Inc	AYI	0.02%	0.43%	0.00%	10.00%	0.00%
Alliance Data Systems Corp	ADS	0.05%	1.12%	0.00%	13.80%	0.01%
LKQ Corp	LKQ	0.04%	n/a	n/a	13.65%	0.01%
Nielsen Holdings PLC	NLSN	0.05%	4.45%	0.00%	9.75%	0.00%
Garmin Ltd	GRMN	0.05%	3.61%	0.00%	6.30%	0.00%
Cimarex Energy Co	XEC	0.04%	0.64%	0.00%	65.22%	0.03%
Zoetis Inc	ZTS	0.17%	0.60%	0.00%	13.97%	0.02%
Digital Realty Trust Inc	DLR	0.09%	3.82%	0.00%	7.28%	0.01%
Equinix Inc	EQIX	0.14%	2.17%	0.00%	24.50%	0.04%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield		1.97%	
[2] Estimated Weighted Average Long-Term Growth Rate		12.98%	
[3] S&P 500 Estimated Required Market Return		15.08%	
[4] Risk-Free Rate	3.07%	3.58%	4.10%
[5] Implied Market Risk Premium	12.01%	11.50%	10.98%

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 Inc	DISCK	0.03%	n/a	n/a	6.00%	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]	3.07%	0.580	15.08%	12.01%	10.04%
Near-term projected 30-year U.S. Treasury bond yield (Q3 2018 - Q3 2019) [2]	3.58%	0.580	15.08%	11.50%	10.25%
Projected 30-year U.S. Treasury bond yield (2019 - 2023) [3]	4.10%	0.580	15.08%	10.98%	10.47%
				Average:	**10.25%**
				Median:	**10.25%**
Proxy Group Average Value Line Beta					
Current 30-day average of 30-year U.S. Treasury bond yield [1]	3.07%	0.693	15.08%	12.01%	11.39%
Near-term projected 30-year U.S. Treasury bond yield (Q3 2018 - Q3 2019) [2]	3.58%	0.693	15.08%	11.50%	11.55%
Projected 30-year U.S. Treasury bond yield (2019 - 2023) [3]	4.10%	0.693	15.08%	10.98%	11.71%
				Average:	**11.55%**
				Median:	**11.55%**

Notes:

[1] Source: Bloomberg Professional, 30-day average as of April 30, 2018
[2] Source: Blue Chip Financial Forecasts, Vol. 37, No. 5, May 1, 2018, at 2
[3] Source: Blue Chip Financial Forecasts, Vol. 36, No. 12, December 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]

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☒ **Public Document**

Xcel Energy
Docket No.: E002/M-17-818
Response To: Department of Commerce Information Request No. 3
Requestor: Matthew Landi; Nancy Campbell
Date Received: December 13, 2017

Question:
Topic: Forecasted vs. Actual Data for 2017; Production Tax Credits; ADIT Prorate
Reference(s): Petition, page 17; Attachments C and H

1. Please update the 2017 Tracker found in Attachment C with actual data for October, November, and December of 2017.

2. Please update the production tax credit (PTC) tracker found in Attachment H with actual data for October, November, and December of 2017.

3. Please update all other areas of the filing that are impacted by use of actual data rather than forecasted data for October, November, and December of 2017, including removal of the Accumulated Deferred Income Tax (ADIT) prorate amounts.

4. Please calculate the impact that using actual data for October, November, and December of 2017 will have on the 2017 Revenue Requirement.

   a. Please update all areas of the petition that are impacted by this change.

5. Please provide the PTCs included in Docket E002/GR-15-826 for both: (1) the total company; and (2) the Minnesota jurisdictional portion and the allocator used, including support for allocator used.

6. Please explain and provide support for Xcel's position on prorated ADIT in this petition, including whether the prorated ADIT amount will be returned to ratepayers in the following year, once amounts become actual/historical.

<u>Response:</u>

The Company requests an extension for this Information Request since 2017 activity has not been completed. We will provide our response when 2017 activity has been completed and recorded in our books and records to provide a complete and coherent response package.

<u>Supplement:</u>

1. Please see Attachment 1 to this response (Attachment C in the petition) for the updated revenue requirements for 2017 actuals. This shows a refund amount of $13.5 million (the previously filed amount was $10.4 million). Please note capital revenue requirements have changed back to January because annual deferred taxes are spread evenly over the 12 months. Additionally, the PTC tracker amount has changed slightly back to January because we have updated the rate case energy allocator used to calculate the PTC true-up. The 2017 capital revenue requirements also include an update to exclude tax bonus depreciation in the fourth quarter of 2017, consistent with the Tax Cuts and Jobs Act (TCJA).

2. Please see Attachment 2, page 2 to this response (Attachment H in the petition), for the PTC tracker updated for 2017 actuals. As noted above in part 1, the PTC true-up amount has changed slightly back to January because we have updated the rate case energy allocator used to calculate the PTC true-up.

3. We will provide a full package of updated attachments when we supplement our filing for the full impact of the TCJA. We anticipate providing this supplement with our Reply Comments.

4. We will provide a full package of updated attachments when we supplement our filing for the full impact of the TCJA. We anticipate providing this supplement with our Reply Comments.

5. Attachment 2, page 1 to this response provides the total company Production Tax Credit forecast as of August 2015, which was used as the support for the PTCs included in Docket No. E002/GR-15-826. The 2017-2019 amounts from the August 2015 forecast are from rows 67-71 of Attachment H, excluding Courtenay

as that is not included in base rates. In reviewing this response, we found that the comparison to the rate case should have used the same allocation factors across 2017-2019, not each year's forecast. Attachment 2, page 1 updates this allocation.

6. At the time of the previous RES Rider order (Docket No. E002/M-15-805), the Company anticipated that it would request a Private Letter Ruling (PLR) from the IRS to clarify several topics related to its ratemaking in Minnesota. However, in the subsequent months, the IRS issued several Private Letter Rulings that provide sufficient guidance such that the Company feels a specific request for its ratemaking is not necessary.

   In particular, PLR #201717008, provided as Attachment 3 to this response, specifically addresses rate riders and true-ups and provides the basis for the Company's position. We note that PLR # 201739001 also provides key guidance for the Company's understanding of ADIT prorate, but is focused on forward-looking rate cases setting base rates and the treatment for interim rates.

   The following chart summarizes the Company's recommended treatment for rate riders:

Current Docket, 17-818	**2016**	**2017**	**2018**	**2019**
Previous Docket's data (A) 15-805 on 2016 "test year"	Actuals, no prorate	N/A		
Current Docket's data (B) 17-818 on 2018 "test year"		Actuals, no prorate	17-818 Fcst, prorated	
True-up comparison		Carryover	N/A	
Subsequent Docket	**2016**	**2017**	**2018**	**2019**
Current Docket's data (B) 17-818 on 2018 "test year"		Actuals, no prorate	17-818 Fcst, un-prorated	
Subsequent Docket's data (C) 2019 "test year"			New actuals, no prorate	New Fcst, prorated
True-up comparison			C minus B	N/A

   We note that whenever a given rate is set, the months prior to that date can be treated as actuals, without proration. In the previous docket, E002/M-15-805, the Commission chose to set the rate after the "test year" had passed. We assume the current docket will be updated for 2017 actuals. Therefore 2016 and 2017 in the summary table above, are not subject to proration.

The Company's position is that in a current docket, the rate representing forecast periods is set using the proration formula. In the next docket, the true-up for the previous docket will be based on the difference between the revenue requirements with the forecast ADIT un-prorated compared to the ADIT updated to actuals.

We note that PLR #201717008, page 11, explicitly disallows the true-up of forecasted ADIT with prorate and actuals with no-prorate because it would reverse the economic effect of the proration.

The method outlined above provides a reasonable approach that abides by the IRS normalization requirements, and does not require significantly extended regulatory procedural schedules.

Preparer:	James Aurand
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Department:	Revenue Requirements – North
Telephone:	612-337-2076
Date:	December 22, 2017

Supplement

Preparer:	Joanna Yugo
Title:	Principal Rate Analyst
Department:	Revenue Requirements – North
Telephone:	612-215-4633
Date:	February 12, 2018

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

Docket No. E002/M-17-818
Information Request No. DOC-3
Attachment 1 - 1 of 1

Update to Petition Attachment C

	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**
			*Actual**	*Actual**	*Actual**	*Actual**	*Actual**	*Actual**	*Actual**	*Actual**	*Actual**	*Actual**	*Actual**	*Actual**	
Line No.															
1	Wind Projects:														
2	Courtenay Wind		452,300	685,277	426,795	1,462,128	(29,948)	936,311	1,461,433	1,438,887	701,492	328,984	434,917	285,920	8,584,497
3	Blazing Star I (Self-build)		(313)	(312)	(310)	(308)	(306)	(305)	(303)	(301)	(299)	(18,127)	(289)	34,589	13,416
4	Blazing Star II (Self-build)		(220)	(219)	(218)	(217)	(215)	(214)	(213)	(212)	(210)	(13,597)	1,759	23,864	10,089
5	Foxtail (Self-build)		(1,010)	(1,005)	(999)	(994)	(988)	(982)	(977)	(971)	(966)	(67,112)	15,931	110,698	50,625
6	Freeborn (Self-build)		(363)	(361)	(359)	(357)	(355)	(353)	(351)	(349)	(347)	(22,936)	3,509	39,601	16,977
7	Crowned Ridge (BOT)		(763)	(758)	(754)	(750)	(746)	(742)	(737)	(733)	(729)	(53,959)	18,085	82,547	39,962
8	Lake Benton (BOT)		(19)	(19)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(1,093)	76	2,027	845
9	Wind Projects Total		449,612	682,604	424,136	1,459,484	(32,576)	933,697	1,458,834	1,436,302	698,923	152,160	473,989	579,246	8,716,410
10															
11	RES PTC Tracker		561,870	(2,370,423)	(2,035,975)	(571,704)	30,355	(816,642)	35,870	(446,027)	(1,492,392)	(1,321,024)	(995,274)	(2,041,651)	(11,463,017)
12	REC Sales Credit		(4,912,560)	-	-	-	-	-	(5,639,440)	-	-	-	-	-	(10,552,000)
13	ADIT Prorate		-	-	-	-	-	-	-	-	-	-	-	-	-
14															
15	**Revenue Requirement Subtotal**		**(3,901,078)**	**(1,687,819)**	**(1,611,839)**	**887,781**	**(2,222)**	**117,055**	**(4,144,736)**	**990,275**	**(793,469)**	**(1,168,864)**	**(521,285)**	**(1,462,405)**	**(13,298,607)**
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**		**(3,301,889)**	**(1,088,631)**	**(1,012,650)**	**1,486,969**	**596,967**	**716,243**	**(3,545,548)**	**1,589,464**	**(194,280)**	**(569,675)**	**77,903**	**(863,216)**	**(6,108,344)**
20	Revenue Collections		1	141	1	1	779,779	973,561	1,090,352	986,550	986,602	861,800	855,468	893,427	7,427,683
21	Balance		(3,301,890)	(4,390,662)	(5,403,313)	(3,916,345)	(4,099,157)	(4,356,475)	(8,992,374)	(8,389,461)	(9,570,344)	(11,001,819)	(11,779,383)	(13,536,026)	

* Note - Updating revenue requirements for the remaining months of 2017 actuals impacts all months of the year as annual deferred tax expense is spread evenly over the 12 months. Additionally, the PTC tracker amount has changed slightly since January due to a change in the rate case energy allocator used to calculate the PTC true-up.

Line #		From rate case 15-826 [1] 2017	From rate case 15-826 [1] 2018	From rate case 15-826 [1] 2019	From RES petition 17-818, Att H 2017	From RES petition 17-818, Att H 2018	From RES petition 17-818, Att H 2019	DIFFERENCE 2017	DIFFERENCE 2018	DIFFERENCE 2019
1	**Qualifing Production (MWh)**									
2	Grand Meadows	315,401	257,585	-	312,966	250,525	-	(2,435)	(7,060)	-
3	Nobles	671,194	671,815	671,733	700,027	720,151	720,151	28,833	48,336	48,418
4	Pleasant Valley	704,321	704,546	704,549	832,947	802,416	802,381	312,574	281,527	281,480
5	Border Winds	520,373	520,889	520,901	644,032	619,412	619,412	(60,289)	(85,134)	(85,137)
7	**Total Production**	2,211,289	2,154,835	1,897,183	2,489,971	2,392,504	2,141,944	278,682	237,669	244,761
8										
9	Tax credit per MW hour	$ 23.00	$ 23.00	$ 23.00	$ 24.00	$ 24.00	$ 24.00			
10	Tax Credit value $000s (line 7 * line 9 / 1000)	$ 50,860	$ 49,561	$ 43,635	$ 59,759	$ 57,420	$ 51,407	$ 8,900	$ 7,859	$ 7,771
11										
12	Total system sales (MWh)				35,614,128	35,372,267	35,386,810			
13	State of MN sales (MWh)				31,121,684	30,839,793	30,832,218			
14	State of MN Energy Allocator [2]	87.3278%	87.3278%	87.3278%	87.3858%	87.1864%	87.1291%			
15										
16	IA Total system sales (MWh)				42,559,730	42,380,597	42,479,952			
17	NSP-M system sales (MWh)				35,754,617	35,563,804	35,654,209			
18	Interchange Agreement Energy Allocation [3]	83.6446%	83.6446%	83.6446%	84.0104%	83.9153%	83.9318%			
19	Revenue Requirement Conversion Factor [4]	1.705611	1.705611	1.705611	1.705611	1.403312	1.403312			
20										
21	**Revenue Requirement in $000s**	**$ (63,364)**	**$ (61,747)**	**$ (54,364)**	**$ (74,827)**	**$ (58,953)**	**$ (52,755)**	**$ (11,463)**	**$ 2,793**	**$ 1,609**
22	(-1 * ln 10 * ln 14 * ln 18 * ln 19)									

Notes

1 Rate case PTC source data found in Application, Vol 4A, Tab P8 Tax Credits, page P8-4
2 Rate case energy allocator found in Application, Vol 4A, Tab VII Budget Allocators, page VII-1
3 Rate case IA energy allocator found in Application, Vol 4A, Tab B4 Other, page B4-1
4 The 2018 and 2019 RES conversion factor has been updated to be consistent with the tax reform corporate composite tax rate of 28.74%

Update to Petition Attachment H

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	Actual Oct-17	Actual Nov-17	Actual Dec-17	Total 2017
1	Wind Production (kWh) A	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	33,723,636	32,139,133	29,506,469	**312,965,640**
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	72,403,397	69,692,508	66,962,171	**700,026,790**
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	85,974,973	83,892,093	78,055,509	**832,946,820**
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	62,675,924	64,844,332	67,230,050	**644,031,696**
5		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	77,564,862	73,570,444	78,425,828	**777,048,617**
6		Blazing Star I	Dec-19	Nov-29													-
7		Foxtail	Dec-19	Nov-29													-
8		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**	**332,342,792**	**324,138,510**	**320,180,029**	**3,267,019,564**
13																	
14																	
15		B PTC Factor per kWh		$0.024													
16																	
17	PTC Value ($0.024 per kWh) C = A x B	Grand Meadows			584,514	827,068	836,255	656,886	643,992	512,765	276,787	348,029	536,018	809,367	771,339	708,155	**7,511,175**
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	1,737,682	1,672,620	1,607,092	**16,800,643**
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	2,063,399	2,013,410	1,873,332	**19,990,722**
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	1,504,222	1,556,264	1,613,521	**15,456,760**
21		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	1,861,557	1,765,691	1,882,220	**18,649,168**
22		Blazing Star I			-	-	-	-	-	-	-	-	-	-	-	-	-
23		Foxtail			-	-	-	-	-	-	-	-	-	-	-	-	-
24		Crowned Ridge			-	-	-	-	-	-	-	-	-	-	-	-	-
25		Lake Benton			-	-	-	-	-	-	-	-	-	-	-	-	-
26		Blazing Star II			-	-	-	-	-	-	-	-	-	-	-	-	-
27		Freeborn			-	-	-	-	-	-	-	-	-	-	-	-	-
28		**Total PTC Value**			**6,933,104**	**7,450,040**	**7,688,837**	**6,810,566**	**6,533,853**	**5,667,717**	**4,102,221**	**3,565,961**	**6,216,298**	**7,976,227**	**7,779,324**	**7,684,320**	**78,408,468**
29																	
30																	
31		D 2017 RR Tax Gross-up		1.705611462													
32		2018/2019 RR Tax Gross-up		1.403311816													
33																	
34	PTC Revenue Requirements E = C x D	Grand Meadows			996,954	1,410,657	1,426,326	1,120,392	1,098,400	874,578	472,091	593,602	914,238	1,380,466	1,315,605	1,207,837	**12,811,146**
35		Nobles			2,386,988	2,882,270	3,212,903	2,879,004	2,504,806	1,884,341	1,311,571	1,043,880	1,991,881	2,963,810	2,852,840	2,741,075	**28,655,369**
36		Pleasant Valley			2,761,590	3,445,688	3,411,774	2,943,993	2,913,595	2,392,961	1,520,345	1,805,976	2,751,854	3,519,357	3,434,095	3,195,177	**34,096,405**
37		Border Winds			2,351,527	2,161,085	2,339,896	2,150,338	1,783,527	2,060,445	1,901,040	1,216,396	2,426,933	2,565,618	2,654,382	2,752,040	**26,363,227**
38		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	2,517,682	3,175,093	3,011,583	3,210,336	**31,808,235**
39		Blazing Star I		*Att. G, pg. 1-3*	-	-	-	-	-	-	-	-	-	-	-	-	-
40		Foxtail		*Att. G, pg. 16-18*	-	-	-	-	-	-	-	-	-	-	-	-	-
41		Crowned Ridge		*Att. G, pg. 10-12*	-	-	-	-	-	-	-	-	-	-	-	-	-
42		Lake Benton		*Att. G, pg. 22-24*	-	-	-	-	-	-	-	-	-	-	-	-	-
43		Blazing Star II		*Att. G, pg. 4-6*	-	-	-	-	-	-	-	-	-	-	-	-	-
44		Freeborn		*Att. G, pg. 19-21*	-	-	-	-	-	-	-	-	-	-	-	-	-
45		**Total PTC Value**			**11,825,182**	**12,706,874**	**13,114,169**	**11,616,179**	**11,144,215**	**9,666,923**	**6,996,795**	**6,082,144**	**10,602,589**	**13,604,344**	**13,268,504**	**13,106,464**	**133,734,382**
46																	
47																	
48		F '17 Energy Allocator		73.4132%													
49		F '18 Energy Allocator		73.1627%													
50		F '19 Energy Allocator		73.1290%													
51																	
52	MN Jur PTC Value G = E x F	Grand Meadows			731,895	1,035,608	1,047,111	822,515	806,370	642,055	346,577	435,782	671,171	1,013,443	965,827	886,712	**9,405,067**
53		Nobles			1,752,363	2,115,966	2,358,694	2,113,568	1,838,858	1,383,354	962,866	766,345	1,462,303	2,175,827	2,094,360	2,012,309	**21,036,812**
54		Pleasant Valley			2,027,370	2,529,589	2,504,691	2,161,278	2,138,962	1,756,748	1,116,133	1,325,824	2,020,223	2,583,671	2,521,078	2,345,680	**25,031,248**
55		Border Winds			1,726,330	1,586,521	1,717,792	1,578,631	1,309,344	1,512,638	1,395,614	892,995	1,781,688	1,883,501	1,948,665	2,020,359	**19,354,078**
56		**Sub Total Base Rate Wind Farms**			6,237,959	7,267,682	7,628,287	6,675,992	6,093,534	5,294,796	3,821,189	3,420,947	5,935,386	7,656,443	7,529,930	7,265,060	**74,827,206**
57		Courtenay			2,443,281	2,060,835	1,999,238	1,851,812	2,087,786	1,801,998	1,315,379	1,044,147	1,848,310	2,330,936	2,210,898	2,356,809	**23,351,430**
58		Blazing Star I			-	-	-	-	-	-	-	-	-	-	-	-	-
59		Foxtail			-	-	-	-	-	-	-	-	-	-	-	-	-
60		Crowned Ridge			-	-	-	-	-	-	-	-	-	-	-	-	-
61		Lake Benton			-	-	-	-	-	-	-	-	-	-	-	-	-
62		Blazing Star II			-	-	-	-	-	-	-	-	-	-	-	-	-
63		Freeborn			-	-	-	-	-	-	-	-	-	-	-	-	-
64		**Total MN Jur PTC Value**			**8,681,240**	**9,328,517**	**9,627,526**	**8,527,804**	**8,181,320**	**7,096,794**	**5,136,568**	**4,465,094**	**7,783,696**	**9,987,379**	**9,740,828**	**9,621,870**	**98,178,636**
65																	
66																	
67	H	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**
68		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**
69		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**
70		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	938,722	**11,968,579**
71		**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**	**4,192,601**	**50,859,647**
72	Base Rate Test Year PTC Forecast from 15-826																
73																	
74		I 15-826 Energy Allocator		73.0450%													
75		J RR Tax Gross-up		1.705611462													
76																	
77		Grand Meadows			1,109,430	660,437	827,553	846,379	841,106	619,117	548,884	390,165	607,197	910,766	918,159	758,580	**9,037,773**
78		Nobles			1,856,405	1,455,323	1,717,687	1,776,315	1,939,075	1,398,673	1,153,072	953,491	1,369,645	1,945,150	2,028,908	1,639,230	**19,232,974**
79		Pleasant Valley			2,420,734	1,566,017	1,806,632	1,878,670	1,877,524	1,381,136	1,249,753	889,332	1,424,777	2,010,397	2,021,171	1,656,079	**20,182,223**
80	K = H x I x J	Border Winds			1,413,258	1,215,482	1,240,440	1,602,925	1,466,183	1,079,228	905,350	741,932	1,041,375	1,469,106	1,566,418	1,169,520	**14,911,218**
81		**Total MN Jur RR Base Rate Test Year PTC Forecast**			**6,799,828**	**4,897,260**	**5,592,312**	**6,104,289**	**6,123,889**	**4,478,154**	**3,857,059**	**2,974,919**	**4,442,994**	**6,335,419**	**6,534,656**	**5,223,409**	**63,364,188**
82																	
83																	
84	PTC True-up (Actual PTCs vs Base Rate Fcst) L = K - G	Grand Meadows			377,535	(375,170)	(219,559)	23,863	34,736	(22,938)	202,307	(45,618)	(63,975)	(102,677)	(47,668)	(128,131)	**(367,294)**
85		Nobles			104,042	(660,642)	(641,006)	(337,253)	100,217	15,319	190,206	187,145	(92,658)	(230,677)	(65,452)	(373,079)	**(1,803,839)**
86		Pleasant Valley			393,364	(963,572)	(698,059)	(282,608)	(261,438)	(375,612)	133,620	(436,492)	(595,446)	(573,274)	(499,907)	(689,601)	**(4,849,025)**
87		Border Winds			(313,072)	(371,039)	(477,351)	24,294	156,840	(433,410)	(490,263)	(151,063)	(740,313)	(414,395)	(382,247)	(850,840)	**(4,442,860)**
88		**Total PTC True-up**			**561,870**	**(2,370,423)**	**(2,035,975)**	**(571,704)**	**30,355**	**(816,642)**	**35,870**	**(446,027)**	**(1,492,392)**	**(1,321,024)**	**(995,274)**	**(2,041,651)**	**(11,463,017)**

Att. C

Internal Revenue Service

Number: **201717008**
Release Date: 4/28/2017

Index Number: 167.22-01

Department of the Treasury
Washington, DC 20224

Third Party Communication: None
Date of Communication: Not Applicable

Person To Contact:
, ID No.
Telephone Number:

Refer Reply To:
CC:PSI:B06
PLR-125024-16

Date:
January 25, 2017

In Re:

Legend:

Taxpayer =

Commission A =
Commission B =
State =
Parent =

Season =
Date X =
Date Y =
Date Z =
Director =

Dear :

This letter responds to the request, dated August 11, 2016, submitted on behalf of Taxpayer for a ruling on the application of the depreciation normalization rules of § 168(i)(9) of the Internal Revenue Code ("Code") and § 1.167(l)-1 of the Federal Income Tax Regulations ("Regulations") (together, the "Normalization Rules") to certain Commission and State regulatory procedures which are described below.

The representations set out in your letter follow.

Taxpayer is an investor-owned regulated utility incorporated under the laws of State engaged principally in the transmission and distribution of electric energy and gas service in State. Taxpayer is subject to regulation as to rates and conditions of service by Commission A and Commission B (the Commissions). Both Commissions establish Taxpayer's rates based on its costs, including a provision for a return on the capital employed by Taxpayer in its regulated businesses.

Taxpayer is wholly owned by Parent. Taxpayer is included in a consolidated federal income tax return of which Parent is the common parent. The return is under the audit jurisdiction of the Large Business and International Division of the Internal Revenue Service. Taxpayer is an accrual basis taxpayer and reports on a calendar year basis.

For purposes of Taxpayer's transmission ratemaking, the rate-setting mechanism employed by Taxpayer is a formula rate ("Transmission Formula Rate") which has been approved by Commission A. Rates are set on a calendar year basis. The Transmission Formula Rate is established in two parts: a rate calculated for the next succeeding calendar year ("Transmission Projected Rate") and a true-up calculation for the prior calendar year ("Transmission True-Up"). The Transmission Projected Rate is calculated based on the costs Taxpayer projects it will incur during the coming calendar year (the period for which rates are being set). All elements of ratemaking (including cost of service, rate base, and cost of capital) are projected for this purpose. In the calculation of rate base, a 13-month average is applied to all elements of rate base except for accumulated deferred federal income tax ("ADFIT").

After the actual results for the Transmission Projected Rate year have been recorded, the Transmission True-Up computation then calculates over- or under-recoveries (when compared to the Projected Rate) that occurred during the prior calendar year. Calculated over- or under-recoveries (plus interest) are reflected in rates charged for the year succeeding the year in which the Transmission True-Up is calculated.

Taxpayer has claimed (and continues to claim) accelerated depreciation on all of its public utility property to the full extent those deductions are available under the Code. For Commission A purposes, Taxpayer normalizes the federal income taxes deferred as a result of its claiming these deductions in accordance with the normalization rules. As a consequence, Taxpayer has a substantial balance of ADFIT that is attributable to accelerated depreciation reflected on its Commission A regulated books of account. In its Transmission Formula Rate template, Taxpayer included its ADFIT balance (as appropriately allocated to the jurisdiction) as a reduction in its computation of rate base. In calculating both its Transmission Projected Rate and its Transmission True-Up, Taxpayer derived the ADFIT balance by which it reduced rate base using a simple average of the beginning and ending balances for the relevant rate year, as required by Commission A. Taxpayer did not use the proration methodology that is required for future test periods by § 1.167(l)-1(h)(6) of the Regulations ("Proration Requirement").

In addition to the transmission ratemaking described above, Taxpayer is permitted by Commission B to use riders to recover its costs for specific types of investments whereby those investments (and associated costs) are taken into account outside of a base rate case, the revenue requirement they demand is added as a surcharge to the base rates charged to customers and the elements of ratemaking are "tracked" and revenues "trued-up." Taxpayer currently has several of these riders. With regard to ratemaking, the mechanics of the Riders are similar to those employed in Taxpayer's transmission ratemaking. The rate for each Rider ("Rider Rate") consists of two components: a projected rate calculation ("Rider Projected Rate") and a true-up calculation ("Rider True-Up"). On or before Date X of each year, Taxpayer files with Commission B to reset its Rider Rate for each of the Riders. These rates are requested to become effective on Date Y of the same year and remain in effect for the subsequent twelve months and therefore through Date Z of the subsequent year. All Riders employ a future test period. To compute the Rider Projected Rate, Taxpayer calculates a revenue requirement for each month of the future test period. All elements of rate base (gross plant, accumulated depreciation and ADFIT) are forecast for each month of the period for which the rates will be in effect. Taxpayer computes a return for each month based on the average rate base during that month (taking into account changes in ADFIT balances). To this it adds the forecasted depreciation, operation and maintenance expenses and other costs for the month to derive the Rider Projected Rate.

To compute the Rider True-Up, Taxpayer calculates a revenue requirement based on the results from the previous period (a portion of which are actual and a portion of which are re-forecasted) that has not been trued-up. This revenue requirement is then compared to the revenues actually collected during the period. Any imbalance (along with interest) is charged or credited to customers as the Rider True-Up for the forthcoming effective rate period.

For purposes of its Rider ratemaking, Taxpayer normalizes the federal income taxes deferred as a result of its claiming accelerated depreciation in accordance with the Normalization Rules, as required by Commission B. As a consequence, Taxpayer has a substantial balance of ADFIT that is attributable to accelerated depreciation reflected on its State regulated books of account. In its Rider Rate filings, Taxpayer includes its ADFIT balance as a reduction in its computation of rate base. Similar to Taxpayer's Transmission Projected Rate and its Transmission True-Up, in calculating both its Rider Projected Rate and its Rider True-Up, Taxpayer derives the ADFIT balance by which it reduces rate base using a simple average of the beginning and ending balances for the relevant rate month. Taxpayer has not applied the proration methodology required for future test periods as described by § 1.167(l)-1(h)(6) of the Regulations.

After the Service published rulings that addressed circumstances in which utility taxpayers employed ratemaking very similar to Taxpayer's Transmission Formula Rate and somewhat similar to Taxpayer's State Riders, Taxpayer's tax department personnel reviewed § 167(l)-1(h)(6) of the Code and Taxpayer's treatment of its ADFIT in its Transmission Formula Rate filings and its State Riders and concluded that its Transmission Projected Rate and its Rider Projected Rate were subject to the Proration Requirement. That is, they concluded that Taxpayer must employ the computation methodology described in § 1.167(l)-1(h)(6) of the Regulations when calculating the ADFIT balance it used as an offset to rate base in those rate filings. They became concerned that Taxpayer had not properly observed the Proration Requirement in earlier Commission A and Rider filings.

Taxpayer represents that Taxpayer will be initiating the measures necessary to conform to the Normalization Rules for its Transmission Projected Rate. Once the Service clarifies the measures that are necessary to conform its Transmission True-Up, Rider Projected Rates, and Rider True-Ups to the Normalization Rules, Taxpayer will initiate those measures at the earliest available opportunity.

Taxpayer requests that we rule as follows:

1. Taxpayer's Transmission Projected Rate and Rider Projected Rates employ a future test period and, therefore, are subject to the Proration Requirement.
2. If Taxpayer employs a future test period in its Transmission Projected Rate and its Rider Projected Rates and the Proration Requirement applies, in computing Taxpayer's Transmission Projected Rate and its Rider Projected Rates, the Consistency Rule does not require that any averaging convention applied to other elements of rate base also apply to Taxpayer's prorated ADFIT balance.
3. Taxpayer's Transmission True-Up and Rider True-Ups employ an historical test period and, therefore, are not subject to the Proration Requirement.
4. If Requested Ruling #3 is affirmative, in computing its Transmission True-Up and Rider True-Ups, the Proration Requirement does not apply only to the differences between Taxpayer's originally projected changes in its ADFIT balances and its experienced changes in those balances. The Proration Requirement continues to apply to the originally projected changes.
5. If Requested Ruling #4 is affirmative, where, in a Transmission True-Up or Rider True-Up calculation, a difference between Taxpayer's originally projected changes in its ADFIT balances and its experienced changes in those balances is attributable to Taxpayer's over-projection in its Transmission Projected Rate or Rider Projected Rate of an increase or decrease in its ADFIT balance, it would be consistent with the Normalization Rules for Taxpayer to reverse the prorated ADFIT used in its Transmission Projected Rate or Rider Projected Rate calculation to the extent of the over-projection.
6. If Requested Ruling #4 is affirmative, where, in a Transmission True-Up or Rider True-Up calculation, a difference between Taxpayer's originally projected changes in its ADFIT balances and its experienced changes in those balances is attributable to Taxpayer's over-projection in its Transmission Projected Rate or

its Rider Projected Rate of an increase or decrease in its ADFIT balance, it would be consistent with the Normalization Rules for Taxpayer to reflect the non-prorated change in the ADFIT balances.

7. In order to comply with the Consistency Rule, it is not necessary that Taxpayer use the same averaging convention it uses in computing the other elements of rate base (a 13-Month Average) in computing its ADFIT balance for purposes of its Transmission Formula Rate.
8. If Requested Ruling #1 is affirmative, and/or Requested Ruling #2 and/or Requested Ruling #7 is negative, if Taxpayer reduced rate base by an amount in excess of the limitation provided for in §1.167(l)-1(h)(6) of the Regulations due to its failure to conform to the Proration Requirement and/or it failed to comply with the Consistency Rule as described above, any such failure by Taxpayer in any year prior to taking the necessary corrective action was not a violation of the Normalization Rules.

Law and Analysis

For purposes of the Law and Analysis portion of this ruling letter, references to "Projected Rates" shall include both Taxpayer's Transmission Projected Rate and its Rider Projected Rates. Similarly, references to "True-Ups" shall include both Taxpayer's Transmission True-Up and its Rider True-Ups.

<u>Issues 1 and 3</u>

Section 1.167(l)-1(h)(6) of the Regulations sets forth normalization requirements with respect to public utility property. Under § 1.167(l)-1(h)(6)(i), a taxpayer does not use a normalization method of accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes excluded from the rate base, or treated as cost-free capital, exceeds the amount of the reserve for the period used in determining the taxpayer's ratemaking tax expense. Section 1.167(l)-1(h)(6)(ii) also provides the procedure for determining the amount of the reserve for deferred taxes to be excluded from rate base or to be included as no-cost capital.

Section 1.167(l)-1(h)(6)(ii) of the Regulations provides that for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under § 1.167(l)-1(h)(6)(i), if solely an historical period is used to determine depreciation for federal income tax expense for ratemaking purposes, then the amount of the reserve account for the period is the amount of the reserve (determined under § 1.167(l)-1(h)(2)) at the end of the historical period. Section 1.167(l)-1(h)(6)(ii) provides that if solely a future period is used for such determination, the amount of the reserve account for the period is the amount of the reserve at the beginning of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during such period.

Section 1.167(l)-1(h)(6)(ii) of the Regulations provides if, in determining depreciation for ratemaking tax expense, a period (the "test period") is used which is part historical and part future, then the amount of the reserve account for this period is the amount of the reserve at the end of the historical portion of the period and a pro rata amount of any projected increase to be credited to the account during the future portion of the period. The pro rata amount of any increase during the future portion of the period is determined by multiplying the increase by a fraction, the numerator of which is the number of days remaining in the period at the time the increase is to accrue, and the denominator of which is the total number of days in the future portion of the period.

Section 1.167(l)-1(h)(6)(i) of the Regulations makes it clear that the reserve excluded from rate base must be determined by reference to the same period as is used in determining ratemaking tax expense. A taxpayer may use either historical data or projected data in calculating these two amounts, but it must be consistent. As explained in § 1.167(l)-1(a)(1), the rules provided in § 1.167(l)-1(h)(6)(i) are to insure that the same time period is used to determine the deferred tax reserve amount resulting from the use of an accelerated method of depreciation for cost of service purposes and the reserve amount that may be excluded from the rate base or included in no-cost capital in determining such cost of services.

If a taxpayer chooses to compute its ratemaking tax expense and rate base exclusion amount using projected data then it must use the formula provided in § 1.167(l)-1(h)(6)(ii) of the Regulations to calculate the amount of deferred taxes subject to exclusion from the rate base. This formula prorates the projected accruals to the reserve so as to account for the actual time these amounts are expected to be in the reserve. As explained in § 1.167(l)-1(a)(1), the formula in § 1.167(l)-1(h)(6)(ii) provides a method to determine the period of time during which the taxpayer will be treated as having received amounts credited or charged to the reserve account so that the disallowance of earnings with respect to such amounts through rate base exclusion or treatment as no-cost capital will take into account the factor of time for which such amounts are held by the taxpayer.

The purpose of the proration formula is the same as that of the requirement for consistent periods discussed above: to prevent the immediate flow-through of the benefits of accelerated depreciation to ratepayers. The proration formula stops flow-through by limiting the deferred tax reserve accruals that may be excluded from rate base, and thus the earnings on rate base that may be disallowed, according to the length of time these accruals are actually in the reserve account.

The effectiveness of § 1.167(l)-1(h)(6)(ii) of the Regulations in resolving the timing issue has been limited by its failure to define some key terms. Nowhere does this provision state what is meant by the terms "historical" and "future" in relation to the test period for determining depreciation for ratemaking tax expense. How are these time periods to be measured? One interpretation focuses on the type or quality of the data used in the ratemaking process. According to this interpretation, the historical period is that portion of the test period for which actual data is used, while the portion of the period for which data is estimated is the future period. The second interpretation focuses on when the utility rates become effective. Under this interpretation, the historical period is that portion of the test period before rates go into effect, while the portion of the test period after the effective date of the rate order is the future period.

The first interpretation, which focuses on the quality of the ratemaking data, is an attractive one. It proposes a simple rule, easy to follow and to enforce: any portion of the reserve for deferred taxes based on estimated data must be prorated in determining the amount to be deducted from rate base. The actual passage of time between the date ratemaking data is submitted and the date rates become effective is of no importance. But this interpretation of the regulations achieves simplicity at the expense of precision; in other words, it is overbroad. The proration of all estimated deferred tax data does serve to magnify the benefits of accelerated depreciation to the utility, but this is not the purpose of normalization. Congress was explicit: normalization "in no way diminishes whatever power the [utility regulatory] agency may have to require that the deferred taxes reserve be excluded from the base upon which the utility's permitted rate of return is calculated." H.R. Rep. No. 413, 91st Cong., 1st Sess. 133 (1969).

In contrast, the second interpretation of § 1.167(l)-1(h)(6)(ii) of the Regulations is consistent with the purpose of normalization, which is to preserve for regulated utilities the benefits of accelerated depreciation as a source of cost-free capital. The availability of this capital is ensured by prohibiting flow-through. But whether or not flow-through can even be accomplished by means of rate base exclusions depends primarily on whether, at the time rates become effective, the amounts originally projected to accrue to the deferred tax reserve have actually accrued.

If rates go into effect before the end of the test period, and the rate base reduction is not prorated, the utility commission is denying a current return for accelerated depreciation benefits the utility is only projected to have. This procedure is a form of flow-through, for current rates are reduced to reflect the capital cost savings of accelerated depreciation deductions not yet claimed or accrued by the utility. Yet projected data is often necessary in determining rates, since historical data by itself is rarely an accurate indication of future utility operating results. Thus, the regulations provide that as long as the portion of the deferred tax reserve based on truly projected (future estimated) data is prorated according to the formula in § 1.167(l)-1(h)(6)(ii) of the Regulations, a regulator may deduct this reserve from rate base in determining a utility's allowable return. In other words, a utility regulator using projected data in computing ratemaking tax expense and rate base exclusion must account for the passage of time if it is to avoid flow-through.

But if rates go into effect after the end of the test period, the opportunity to flow through the benefits of future accelerated depreciation to current ratepayers is gone, and so too is the need to apply the proration formula. In this situation, the only question that is important for the purpose of rate base exclusion is the amount in the deferred tax reserve, whether actual or estimated. Once the future period, the period over which accruals to the reserve were projected, is no longer future, the question of when the amounts in the reserve accrued is no longer relevant (at the time the new rate order takes effect, the projected increases have accrued, and the amounts to be excluded from rate base are no longer projected but historical, even though based on estimates).

Taxpayer calculates its Transmission Projected Rate to be effective for the succeeding calendar year. The rate is based on costs Taxpayer projects it will incur during that year. Rates go into effect as of the beginning of the service year. Therefore, rates go into effect before the end of the test period. Similarly, Taxpayer calculates its Rider Rates during Season to be effective during the twelve month period Date Y of the current year through Date Z of the succeeding year. This is calculated based on the costs Taxpayer projects it will incur during that period. The addition of the true-up increases the ultimate accuracy of the rates but does not convert a future test period into an historical test period as those terms are used in the normalization regulations. Accordingly, the test periods for Taxpayer's Transmission Projected Rate and Rider Projected Rate are future test periods, subject to the Proration Requirement , and Taxpayer is required to apply the proration formula in calculating ADFIT for purposes of calculating rate base in these ratemakings.

In contrast, the Taxpayer's True-Ups represent amounts that are incorporated into rates charged to customers after the end of the test period on which those amounts are based. In the case of the Transmission True-Up, the true-up component is determined by reference to a purely historical period. In the case of the Rider True-Ups, the charge is calculated based on results (part historical and part re-forecasted) for a span of time before the effective date of rates including the true-up. Thus, in each case, the test period is one that occurs prior to the effective date of the rates which result from the computation. Accordingly, the Transmission True-Up and Rider True-Up employ an historical test period, and there is no need to use the proration formula to calculate the differences between Taxpayer's projected ADFIT balance and the actual ADFIT balance during the period. The True-Ups are not subject to the Proration Requirement.

<u>Issues 2 and 7</u>

Former § 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former § 167(l)(3)(G) in a manner consistent with that found in section § 168(i)(9)(A). Section 1.167(l)-1(a)(1) of the Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under § 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 168(f)(2) of the Code provides that the depreciation deduction determined under § 168 shall not apply to any public utility property (within the meaning of § 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, § 168(i)(9)(A) of the Code requires that a taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under § 168(i)(9)(A)(ii), if the amount allowable as a deduction under § 168 differs from the amount that would be allowable as a deduction under § 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under § 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of § 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under § 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under § 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base (hereinafter referred to as the "Consistency Rule").

Taxpayer has two requests relating to its compliance with the Consistency Rule. First, Taxpayer requests in requested ruling two that in determining the limitation on the amount by which the ADFIT balance may reduce rate base, the Normalization Rules do not require that the averaging convention applied by Taxpayer to all other elements of rate base (plant, accumulated depreciation, cash working capital, etc.) be applied to its prorated ADFIT balance. That is, Taxpayer requests confirmation that the Normalization Rules do not require Taxpayer to apply both conventions serially to changes in ADFIT balances. Second, Taxpayer requests in requested ruling seven that in order to comply with the Consistency Rule, it is not necessary that Taxpayer use the identical averaging convention it uses in computing the other elements of rate base (a 13-Month Average) in computing its ADFIT balance for purposes of its Transmission Formula Rate.

Taxpayer's requested ruling two is based on the premise that, where the purpose of the regulatory averaging and proration can be shown to be the same, the Consistency Rule should not apply. Taxpayer represents that the purpose of the Proration Requirement is to take into account for ratemaking purposes the economic fact that changes in ADFIT balances in a future test period (and, of course, the attendant cash flows) will occur over a period of time. According to Taxpayer, the critical question is whether the averaging convention has a different purpose. How is it determined if the averaging conventions have a different purpose? According to Taxpayer, the answer appears to lie in the nature of the test period. If the test period is part historical, part future, the timing of the rate base expenditures cannot be what regulatory averaging was meant to address. However, Taxpayer maintains that the purposes of regulatory averaging and proration can be the same when the entire test year is a future test period. Taxpayer proposes that averaging conventions, when applied to entirely future test periods, should presumptively be treated as having the same purpose as the Proration Requirement, thereby negating the necessity to apply both conventions serially to changes in ADFIT balances.

Taxpayer's requested ruling seven acknowledges that § 168(i)(9)(B) of the Code requires consistency between the regulatory conventions used to determine the amount included in the rate base for public utility property, the associated ADFIT attributable to accelerated depreciation, depreciation expense and tax expense included in cost of service. Taxpayer acknowledges that Taxpayer used an averaging convention for ADFIT that in some regard differed from the averaging convention it used for the other elements of rate base, however, Taxpayer used an averaging convention for both purposes and the time period covered by both averaging conventions was identical.

In regard to Taxpayer's requested ruling two, we agree with Taxpayer that averaging conventions, when applied to entirely future test periods, should presumptively be treated as having the same purpose as the Proration Requirement, thereby negating the necessity to apply both conventions serially to changes in ADFIT balances. In regard to Taxpayer's requested ruling seven, while there are minor differences in the convention used to average all elements of rate base including depreciation expense on the one hand, and ADFIT on the other, for purposes of § 168(i)(9)(B), it is sufficient that both are determined by averaging and both are determined over the same period of time. Thus, the calculation of average rate base and ADFIT as described above complies with the consistency requirement of § 168(i)(9)(B).

Because of the two conclusions reached above, the portion of Taxpayer's requested ruling eight which is based on a negative conclusion in Taxpayer's rulings two and seven is moot and will not be considered further, Issues 4, 5, and 6

Because the Service ruled affirmatively with respect to Requested Ruling #3, Taxpayer requests guidance regarding the way it must calculate its True-Ups in order to remain compliant with the Normalization Rules. Taxpayer's True-Ups are derived from a comparison of two amounts. Each is computed by replicating the Projected Rate revenue requirement computation using, in the case of Taxpayer's Transmission True-Up, actual, rather than forecasted, amounts and, in the case of its Rider True-Up, part actual and part re-forecasted amounts. This produces the total revenues with respect to the prior Projected Rate test period which Taxpayer is ultimately allowed to recover (ignoring interest). This permissible revenue requirement is then compared to the revenue actually collected while the Projected Rate was in effect. The difference is the True-Up revenue requirement that is incorporated into rates for the next following rate-effective period. The manner in which the True-Up revenue requirement is derived creates ambiguity.

The mechanics of the True-Up calculations leave open two possible interpretations as to the application of the Normalization Rules. The first interpretation is that it is only the differences between the changes in the ADFIT balances projected for purposes of the Projected Rate calculation and the actual changes in those balances (determined after the fact) that are free of the Proration Requirement. The second interpretation is that the freedom from the Proration Requirement applies not just to the variations between projected ADFIT changes and actual ADFIT changes but to the calculation of the total revenues that Taxpayer is ultimately allowed to recover for the period. The consequence of this second interpretation is that, because the replicated revenue requirement does not incorporate any proration whatsoever, and because it is that revenue requirement to which the Projected Rate revenue requirement is trued-up, the resulting True-Up calculation will entirely reverse the impact of proration that was embedded in the Projected Rate. Thus, this second interpretation effectively neutralizes any Proration Requirement impact that is embedded in the Projected Rate calculation.

The fact that the Projected Rate and the True-Up are treated as two distinct rate-setting processes having distinct test periods, one future and one historical, strongly suggests that proration should matter. And to make proration matter, the freedom from proration can only apply to the variations in the changes in the ADFIT balance used in the True-Up computation, not to the entire change in the ADFIT balances used in that computation. The True-Up component is determined by reference to a purely historical period and, accordingly, there is no need to use the proration formula to calculate the differences between Taxpayer's projected ADFIT balance and the actual ADFIT balance during the period. In calculating the True-Up, proration applies to the original projection amount but the actual amount added to the ADFIT over the test year is not modified by application of the proration formula.

Because Requested Ruling #4 is affirmative, Taxpayer requests guidance on the computation. Specifically, Taxpayer requests guidance in a situation when the actual ADFIT activity is less than the projected amount (that is, there was an over-projection of the ADFIT balance changes used in the Projected Rate calculation). A strict application of the “non-proration” approach may produce curious results because the projected change in the ADFIT balance is prorated while the over-projection is not. According to Taxpayer, non-proration of the variation between the projected ADFIT and the actual ADFIT may produce an ADFIT balance used in the true-up that would be less than either the beginning or ending ADFIT balance. Taxpayer requests (Ruling Request #5) that we rule that, even though the proration methodology is not required to be applied to the variations between projected and actual ADFIT balances, application of that methodology is permissible in certain cases, such as where an over-projection of ADFIT occurred and the prorating of the variation produces a more economically precise result. Taxpayer also requests (Ruling Request #6) that we rule that not applying the proration methodology to the variation between the projected and actual ADFIT balances is also permissible.

We have concluded that the Normalization Rules do not require the application of the proration methodology in the context of an historical test period such as a true-up and thus, we affirm that not applying the proration methodology to the variation between the projected and actual ADFIT balances is permissible under the Normalization Rules. However, as explained in § 1.167(l)-1(a)(1), the formula in § 1.167(l)-1(h)(6)(ii) provides a method to determine the period of time during which the taxpayer will be treated as having received amounts credited or charged to the reserve account so that the disallowance of earnings with respect to such amounts through rate base exclusion or treatment as no-cost capital will take into account the factor of time for which such amounts are held by the taxpayer; it does not exclude the use of the proration formula from being used in all other instances other than where required. Thus, where the regulatory body concludes that proration of variations between projected and actual ADFIT is necessary to accurately reflect the changes captured by the true-up ratemaking and that such use does not result in impermissible flow-through of accelerated depreciation-related benefits, such use of proration is permissible under the Normalization Rules.

Issue 8

Because the Service has ruled in Issue 1 that Taxpayer was required to follow the Proration Requirement applicable to future test periods for the projected revenue requirement for Taxpayer’s Transmission Projected Rate and Rider Projected Rates, prospectively adhering to the Service's interpretation of § 1.167(l)-1(h)(6)(ii) requires adjustments to conform to this ruling.

Taxpayer requests that any such failure by Taxpayer in any year prior to taking the necessary corrective action was not a violation of the Normalization Rules.

Taxpayer has represented that Taxpayer will be initiating the measures necessary to conform to the Normalization Rules for its Transmission Projected Rate. Taxpayer stated that once the Service clarifies the measures that are necessary to conform its Transmission True-Up, Rider Projected Rates, and Rider True-Ups to the Normalization Rules, Taxpayer will initiate those measures at the earliest available opportunity.

Section 168(f)(2) of the Code provides that the depreciation deduction determined under § 168 shall not apply to any public utility property (within the meaning of § 168(i)(10)) if the taxpayer does not use a normalization method of accounting. However, in the legislative history to the enactment of the normalization requirements of the Investment Tax Credit, Congress has stated that it hopes that sanctions will not have to be imposed and that disallowance of the tax benefit (there, the ITC) should be imposed only after a regulatory body has required or insisted upon such treatment by a utility. See Senate Report No. 92-437, 92nd Cong., 1st Sess. 40-41 (1971), 1972-2 C.B. 559, 581.

Both Commission A and Commission B have, at all times, required that utilities under their respective jurisdictions use normalization methods of accounting. Taxpayer also intended at all times to comply with the normalization rules. As concluded above, Taxpayer was required to use the proration methodology in these ratemaking proceedings for its Projected Rates. However, because the Commissions as well as Taxpayer at all times sought to comply, and because Taxpayer will take corrective actions, it is not currently appropriate to apply the sanction of denial of accelerated depreciation to Taxpayer.

Here, Taxpayer's failure to comply with the Normalization Rules in its prior Transmission Formula Rate and Rider Rate proceedings was that it may have offset its rate base by an amount of ADFIT in excess of that permitted. It was not a reduction which Taxpayer, any participant in any of the proceedings, or the regulator in any of the proceedings recognized. No potential proration-related normalization issue was ever identified. Thus, there was clearly no required or insistent treatment that was inconsistent with the Normalization Rules. There was no determination made with respect to Taxpayer's calculation of its ADFIT balance by either Commission.

Any rates that have been calculated using procedures inconsistent with this ruling ("nonconforming rates") which are or which have been in effect and which, under applicable state or federal regulatory law, can be adjusted or corrected to conform to the requirements of this ruling, must be so adjusted or corrected. Where nonconforming rates cannot be adjusted or corrected to conform to the requirements of this ruling due to the operation of state or federal regulatory law, then such correction must be made in the next regulatory filing or proceeding in which Taxpayer's rates are considered.

We rule as follows:

1. Taxpayer's Transmission Projected Rate and Rider Projected Rates employ a future test period and, therefore, are subject to the Proration Requirement.
2. If Taxpayer employs a future test period in its Transmission Projected Rate and its Rider Projected Rates and the Proration Requirement applies, in computing Taxpayer's Transmission Projected Rate and its Rider Projected Rates, the Consistency Rule does not require that any averaging convention applied to other elements of rate base also apply to Taxpayer's prorated ADFIT balance.
3. Taxpayer's Transmission True-Up and Rider True-Ups employ an historical test period and, therefore, are not subject to the Proration Requirement.
4. In computing its Transmission True-Up and Rider True-Ups, the Proration Requirement does not apply only to the differences between Taxpayer's originally projected changes in its ADFIT balances and its experienced changes in those balances. The Proration Requirement continues to apply to the originally projected changes.
5. Where, in a Transmission True-Up or Rider True-Up calculation, a difference between Taxpayer's originally projected changes in its ADFIT balances and its experienced changes in those balances is attributable to Taxpayer's over-projection in its Transmission Projected Rate or Rider Projected Rate of an increase or decrease in its ADFIT balance, it would be consistent with the Normalization Rules for Taxpayer to reverse the prorated ADFIT used in its Transmission Projected Rate or Rider Projected Rate calculation to the extent of the over-projection.
6. Where, in a Transmission True-Up or Rider True-Up calculation, a difference between Taxpayer's originally projected changes in its ADFIT balances and its experienced changes in those balances is attributable to Taxpayer's over-projection in its Transmission Projected Rate or its Rider Projected Rate of an increase or decrease in its ADFIT balance, it would be consistent with the Normalization Rules for Taxpayer to reflect the non-prorated change in the ADFIT balances.
7. In order to comply with the Consistency Rule, it is not necessary that Taxpayer use the same averaging convention it uses in computing the other elements of rate base (a 13-Month Average) in computing its ADFIT balance for purposes of its Transmission Formula Rate.
8. Because Requested Ruling #1 is affirmative, if Taxpayer reduced rate base by an amount in excess of the limitation provided for in §1.167(l)-1(h)(6) of the Regulations due to its failure to conform to the Proration Requirement , any such failure by Taxpayer in any year prior to taking the necessary corrective action was not a violation of the Normalization Rules.

This ruling is based on the representations submitted by Taxpayer and is only valid if those representations are accurate. The accuracy of these representations is subject to verification on audit.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. We are also sending a copy of this letter ruling to the Director.

Sincerely,

Patrick S. Kirwan
Chief, Branch 6
Office of Associate Chief Counsel
(Passthroughs & Special Industries)

cc:

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Xcel Energy
Docket No.: E002/M-17-797
Response To: Office of the Attorney General Information Request No. 203
Requestor: Ryan Barlow
Date Received: March 6, 2018

Question:
Reference: Petition page 14

The Petition states that "[the Company] request[s] of a two-way carrying charge starting January 1, 2019."

Define, Explain, and Quantify the requested two-way carrying charge.

Provide at least two hypothetical scenarios illustrating (1) an under-recovery scenario and (2) an over-recovery scenario.

Explain all benefits (1) for ratepayers and (2) for shareholders of the requested two-way carrying charge.

Response:
The two-way carrying charge would apply interest to the true-up balance, whether the balance is an over-collection or an under-collection.

Factors that might lead to under-recovery include actual costs being higher than forecast, actual sales being lower than forecast, and a timing mismatch of rate implementation compared to the test period especially if annual revenue requirements are increasing due to phased-in eligible investment. In the hypothetical example below, the initial rate is delayed by two quarters in the Test Year 1 and left in place for three periods in Test Year 2. At the end of two test years, a significant true-up balance exists that is more than half of the full year of revenue requirements for Test Year 2, thereby adding a significant amount to the presumed Test Year 3 rate. For ease of illustration, the example assumes a 10% interest rate applied annually, though in practice the interest would be calculated on the monthly balance.

Under-Recovery Example	Year 1				Year 2			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Forecasted and Actual Revenue Requirements	$100	$100	$100	$100	$150	$150	$150	$150
Forecasted and Actual Sales	1000	1000	1000	1000	1000	1000	1000	1000
Forecasted Rate	$0.10	$0.10	$0.10	$0.10	$0.15	$0.15	$0.15	$0.15
Rate in Effect	--	--	$0.10	$0.10	$0.10	$0.10	$0.10	$0.15
True-up Balance	$100	$200	$200	$200	$270	$320	$370	$370
Interest (10% for ease of calc)				$20				$37
Total True-Up Balance				$220				$407

Factors that lead to over-recovery include actual costs being less than forecasted, sales being higher than forecasted, and a timing mismatch of rate implementation compared to the test period especially if annual revenue requirements are declining through depreciation. In the example below, actual revenue requirements are less than forecast in Year 1 and Year 2. At the end of two test years, a significant true-up balance exists that is more than half of the full year of revenue requirements for Test Year 2, thereby significantly skewing the presumed Test Year 3 rate.

	Year 1				Year 2			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Forecasted Revenue Requirements	$100	$100	$100	$100	$150	$150	$150	$150
Forecasted Sales	1000	1000	1000	1000	1000	1000	1000	1000
Rate in Effect	$0.10	$0.10	$0.10	$0.10	$0.15	$0.15	$0.15	$0.15
Actual Revenue Requirements	$75	$75	$75	$75	$125	$125	$125	$125
Actual Sales	1250	1250	1250	1250	1250	1250	1250	1250
True-up Balance	($50)	($100)	($150)	($200)	($283)	($345)	($408)	($470)
Interest				($20)				($47)
Total True-up Balance				($220)				($517)

In both examples, if eligible revenue requirements continue for several more years, the large true-up balances combined with timing mismatches between the rate implementation and the test period can create a yo-yo effect with the implemented rate and lead to customer bill volatility, even though the revenue requirements are relatively flat.

Ratepayers and shareholders would see similar benefits. All parties would have some motivation to match the recovery period with the test period so as to minimize the magnitude of a carrying charge, assuming equal likelihood of an under- or over-collection. The motivation of better matching should lead to smaller true-ups and therefore less bill volatility. Additionally, both the Company and customer are compensated through interest when they are owed money. Should an under-collection occur, the Company would be protected for its time value of money through an interest charge. Should an over-collection occur, the ratepayers would be protected for their time value of money through an interest credit. The longer the mismatch between the test period and the recovery period, the more interest would accrue.

Preparer:	Charles Burdick
Title:	Director of Revenue Analysis
Department:	Revenue Requirements, North
Telephone:	612-330-6646
Date:	March 16, 2018

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-17-797

Dated this 14th day of May 2018

/s/
____
Carl Cronin

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