COMMERCE DEPARTMENT

April 2, 2018

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E002/M-17-797

Dear Mr. Wolf:

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

Petition of Northern States Power Company, doing business as Xcel Energy, for Approval of its Transmission Cost Recovery Rider.

The Petition was filed on November 8, 2017 by:

Holly Hinman
Regulatory Manager
Xcel Energy
414 Nicollet Mall, 401 – 7th Floor
Minneapolis, MN 55401

The Department requests that the Company provide additional information in Reply Comments, and will provide a final set of recommendations to the Minnesota Public Utilities Commission after it has reviewed the information the Company provides.

Sincerely,

/s/ CRAIG ADDONIZIO
Financial Analyst

CA/ja
Attachment

COMMERCE DEPARTMENT

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. E002/M-17-797

I. SUMMARY OF THE UTILITY'S PROPOSAL

On November 8, 2017, Northern States Power Company (NSPM, or the Company) filed a petition (Petition) with the Minnesota Public Utilities Commission (Commission) requesting approval of its 2017-2018 Transmission Cost Recovery (TCR) Rider revenue requirements, tracker balance, and updated TCR adjustment factors.

Specifically, in its Petition, NSPM requested:

- approval of the 2017 and 2018 revenue requirements for seven transmission projects that the Commission determined were eligible for recovery under the TCR Statute in previous TCR Dockets;
- to begin cost recovery for its Advanced Distribution Management System (ADMS) distribution-grid modernization project;
- a return on equity of 10.0 percent to calculate its revenue requirements;
- recovery of its net Midcontinent Independent System Operator (MISO) Regional Expansion Criteria and Benefits (RECB) charges;
- recovery of its 2016 true-up carryover balance resulting from under-collections in prior years;
- approval of its proposed cost allocations between retail and wholesale, its proposed allocations among its different retail classes, and the resulting TCR adjustment factors; and
- approval of its proposed revised TCR tariff sheet and customer notice.

Table 1 summarizes NSPM's proposed 2018 TCR revenue requirements.

Table 1
Proposed TCR Revenue Requirements
($ millions)

	2017 Actual/F'casted	2018 F'casted
ADMS	1.0	2.7
Big Stone-Brookings	3.6	5.9
CAPX2020 - Brookings	39.9	38.8
CAPX2020 - La Crosse Local	5.2	5.2
CAPX2020 - La Crosse MISO	6.7	6.4
CAPX2020 - La Crosse MISO - WI	12.2	11.9
CAPX2020 - Fargo	18.2	17.6
LaCrosse - Madison	5.8	10.0
MISO RECB Sch.26/26a	0.9	0.4
RES Study	0.3	-
ADIT Pro-Rate	0.1	0.6
Transmission Projects	93.9	99.5
Revenue Requirement in Base Rates (ADMS)	(0.5)	(0.7)
TCR True-up Carryover	1.4	9.6
Revenue Requirement (RR)	94.8	108.4
Revenue Collections (RC)	85.1	109.7
Carry Over Balance	9.6	(1.3)

As shown, NSPM has requested approval of 2017 and 2018 revenue requirements of $94.8 million and $108.4 million, respectively. Both totals represent significant increases relative to 2015 and 2016, in which total revenue requirements were $61.5 million and $80.5 million, respectively.[1]

[1] See NSPM's January 27, 2017 Compliance Filing in Docket No. E002/M-15-891 (The 2015 TCR Docket), and DOC Attachment 1. The revenue requirements shown in Table 1 have been revised slightly relative to the Company's Petition, as explained below.

Table 2
Current and Proposed TCR Adjustment Factors

Customer Class	Current Rate	Proposed Rate
Residential ($/kWh)	0.003503	0.004645
Commercial Non-Demand Billed ($/kWh)	0.003384	0.004102
Demand ($/kW)	1.0170	1.2740

Xcel stated that the monthly bill of an average residential customer using 675 kWh of electricity per month would increase by $0.77 per month under its proposed rates. The Department notes, however, that the proposed rates shown in Table 2 were calculated assuming an implementation date of January 2, 2018. NSPM proposed to recalculate its rates based on the actual implementation date to recover its full 2018 revenue requirement over the remaining months of 2018. Therefore, under the Company's proposal, the actual rates approved in this proceeding may be higher than those shown in Table 2. In addition, the Company requested approval of a two-way carrying charge beginning January 1, 2019 to account for "the potential for a misalignment of the time a rate is effective compared to the revenue requirements intended for recovery."[2]

II. DEPARTMENT ANALYSIS

A. PROJECT ELIGIBILITY

1. Transmission Projects

As noted above, all of the transmission projects for which NSPM has requested cost recovery in its Petition were determined to be eligible by the Commission in prior TCR proceedings. There has been no change in the eligibility status of any of the projects, and the Department concludes that all remain eligible for cost recovery via the TCR Rider.

2. ADMS Project Eligibility

In 2015, Minn. Stat. §216B.2425, subd. 2, was amended to require utilities operating under a multi-year rate plan to identify "investments that it considers necessary to modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating

[2] Petition, at 14.

communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies." Subdivision 3 of the same statute was also modified to require the Commission to "certify, certify as modified, or deny certification of the transmission and distribution projects proposed under subdivision 2."

Also in 2015, Minn. Stat. §216B.16, subd. 7b(b) was amended to allow utilities to recover costs associated with investments in distribution facilities to modernize the utility's grid that have been certified by the Commission under section 216B.2425 via TCR riders.

In its June 28, 2016 O*rder Certifying Advanced Distribution-Management System (ADMS) Project Under Minn. Stat. § 216b.2425 and Requiring Distribution Study* (the 15-962 Order) in Docket No. E002/M-15-962 (Docket 15-962), the Commission certified NSPM's proposed ADMS project pursuant to Minn. Stat. §216B.2425. However, in Ordering Point 1 of the 15-962 Order, the Commission stated that "[c]ertification of this project does not imply any decision regarding recovery of the project's costs. Any rider recovery of costs associated with a certified project will be determined in response to a utility petition for rider recovery of those costs under Minn. Stat. § 216B.16, subd. 7b."

In its Petition, NSPM requested to include in its TCR Rider, for the first time, costs associated with its ADMS distribution-grid modernization project. Because the Commission certified the ADMS project, the Department concludes that it is eligible for inclusion in the TCR Rider. The Department addresses the prudency of the Company's proposed costs below.

B. REASONABLENESS OF PROJECT REVENUE REQUIREMENTS AND COST RECOVERY CAPS

1. Transmission Projects

The Commission's 2010 Order in Docket No. E002/M-10-1064 set the standard for evaluation of TCR Project Costs going forward as follows:

> …the Commission finds that TCR project cost recovery through the rider should be limited to the amount of the initial cost estimates at the time the projects are approved as eligible projects, with the opportunity for the Company to seek recovery of excluded costs on a prospective basis in a subsequent rate case. A request to allow cost recovery for project costs above the amount of the initial estimate may be brought for Commission review only if unforeseen or extraordinary circumstances arise on a project.

Table 3 summarizes the Company's initial cost estimates for the transmission projects included in the TCR Rider, current estimates of total costs, and estimated costs through 2018.

Table 3
TCR Actual Costs and Cost Caps

	Estimated Costs at Completion				
Project	Initial Estimate	Initial Escalated to 2015 Dollars	2015 TCR Docket Estimate	Current Estimate	Estimated Investment Through 2018
	[1]	[2]	[3]	[4]	[5]
In-State Projects					
CAPX2020 Brookings	523.9	625.6	477.1	476.5	476.5
CAPX2020 La Crosse Local			91.0	80.0	80.0
CAPX2020 La Crosse MISO			82.9	81.2	81.2
CAPX2020 La Crosse MISO - WI			152.9	148.7	148.7
CAPX2020 La Crosse	276.5	330.3	326.7	310.0	310.0
CAPX2020 Fargo	231.0	275.9	226.2	224.5	224.5
Out of State Projects					
Big Stone - Brookings	92.2		81.3	74.4	74.4
La Crosse - Madison	179.1		179.1	172.6	166.4

Sources:
[1], [2], and [3]: Department's April 21, 2016 Comments in the 2015 TCR Docket
[4]: Petition, Attachment 3B

The Department reviewed NSPM's actual and forecasted capital expenditures for projects included in the TCR rider. All projects except for the CAPX2020 La Crosse project are below their initial cost estimates, and the CAPX2020 La Crosse project is below its initial estimate, escalated to 2015 dollars, which is the cost cap the Department has used in each of Xcel's last two TCR dockets.[3] Additionally, the Department notes that Xcel's current estimates of total expenditures declined from its estimates in the 2015 TCR Docket, significantly for the CAPX 2020 La Crosse project.

Because each project's capital expenditures are below either the initial estimate or the escalated initial estimate, the Department recommends that the Commission approve recovery of the costs proposed in the Petition.

[3] See the Department's September 7, 2016 Comments in the 2015 TCR Docket and its May 8, 2015 Supplemental Comments in Docket No. E002/M-14-852.

2. ADMS Costs and Revenue Requirements

a. Need for ADMS

In Docket 15-962, the Department expressed concern that no clear criteria for certification of distribution projects had been established, and thus there was not a clear way to determine the need for or prudency of the proposed ADMS project.

Regarding the lack of criteria for certification, in its June 28, 2016 Order in Docket 15-962, the Commission stated:

> …the Commission is not persuaded that it is necessary to adopt a comprehensive set of certification criteria at this time, or to delay certification to conduct rulemaking.
>
> Because of ADMS's foundational role in grid modernization, Xcel should be provided with reasonable incentive to move forward with the project expeditiously. One way to encourage rapid development of ADMS is to certify the project now so that Xcel can seek rider recovery. Deferring certification while an exhaustive set of certification criteria is developed would remove much of this incentive.
>
> Moreover, the Commission agrees with Xcel that it can interpret the statute on a case-by-case basis until such time as a comprehensive list of criteria is established. Rather than initiate rulemaking immediately, the Commission is convinced that it is more prudent to develop these criteria over time as the Commission gains experience with grid modernization.

Ultimately, the Commission certified the ADMS project, but qualified its decision as follows:

> The Commission's decision represents only a finding that the project is consistent with the requirements of section 216B.2425. Any rider recovery of costs associated with the project will be determined in response to a petition for rider recovery of those costs under Minn. Stat. § 216B.16, subd. 7b. At that time, Xcel will have the burden of establishing the prudence of the costs it requests to recover through the TCR Rider.

At a high level, the Department considers the question of prudence in two steps. First, should the Company be acquiring an ADMS? And second, assuming it should be, is it planning for and acquiring its ADMS in a reasonable and cost effective manner?

While it seems that the Commission's 15-962 Order intended to settle the first question by establishing that the Company should be acquiring an ADMS system, it is not explicitly stated in the Order. On the one hand the Commission's 15-962 Order certified the ADMS, described it as having a "foundational role" in grid modernization, and stated:

> Xcel should be provided with reasonable incentive to move forward with the project expeditiously. One way to encourage rapid development of ADMS is to certify the project now so that Xcel can seek rider recovery. Deferring certification while an exhaustive set of certification criteria is developed would remove much of this incentive.

On the other hand the Department remains concerned, as it was in Docket 15-962, that there has been no analysis of the Company's actual distribution system that has established a general need that can be met by ADMS or other grid modernization projects, in the comprehensive way that needs for resources are determined in integrated resource planning (IRP) proceedings. Further, neither ADMS itself nor any of the grid modernization projects the Company has discussed in its various grid modernization Dockets have been clearly shown to be beneficial to customers or the pursuit of state energy policy goals.

However, the Department understands that we are still in an exploratory phase with respect to grid modernization, and that the Commission expressed an intention to allow the ADMS project to move forward while other aspects of grid modernization are still being assessed.

b. ADMS Acquisition Process

The Company began its acquisition process by considering alternatives to ADMS. As described on pages 6-7 of Attachment 1A, the Company concluded that none are reasonable. In place of ADMS, the Company could pursue individual projects such as increasing the size of the cables on the distribution grid to accommodate more distributed energy resources (DERs), or installing separate, autonomous versions of the types of projects it plans to integrate with ADMS, such as its supervisory control and data acquisition (SCADA) system. The Company stated that doing so would not allow for effective management of these programs. However, there was no quantitative analyses of the relative costs and benefits of any projects with and without ADMS in place. And, again, it may be the case that the Commission's intent with the 15-962 Order was to establish that ADMS is necessary, in which case alternatives need not be assessed.

Having concluded that ADMS is necessary for its grid modernization efforts, the Company described its process for selecting a vendor for its ADMS system in Attachment 1A of its Petition, on pages 8-14. With assistance from outside consultants, the Company developed a list of requirements for its desired ADMS system, and identified eight vendors capable of meeting the Company's needs, to which it sent requests for proposals. The initial responses were scored based on responsiveness to Xcel's needs and an evaluation of the software cost, and three finalists were selected to present their proposals in person. The Company ultimately selected Schneider Electric.

The Department reviewed the Company's request for proposals, which was provided in response to Information Request No. 102 from the Office of the Attorney General (OAG).[4] At a high level, the Department concludes that the Company's process for selecting a final vendor was reasonable, as it considered cost and non-cost factors such as the vendors' proposals and experience related to the specific projects the Company is considering implementing (e.g. fault location, isolation, and system restoration, integrated volt-var optimization), ease of use, training and support, security, and a number of other relevant factors.

c. Costs included in the Rider

As shown on the Petition's Attachment 1A, page 19, the Company's current total estimated capital cost for the ADMS project is \$69.1 million, consisting of \$29.4 million in labor costs, \$3.2 million in software licensing costs, \$31.0 million for data collection on the Company's existing distribution system, and \$5.6 million in hardware. The Company describes these cost categories on pages 19-21 of Attachment 1A.

On pages 20 and 22 of Attachment 1A, the Company stated that it is not seeking rider recovery of its hardware costs, and instead will include them in a future rate case. The Department notes however, that the Construction Work in Progress (CWIP) included in the revenue requirements the Company calculated more closely matches the Company's estimates of cumulative costs including hardware costs, as shown in the table below.

[4] The Department did not include the Company's response to OAG IR 102 due to its length, but can do so if the Commission would like it to be filed in eDockets.

Table 4
Comparison of Budgeted ADMS Capital Costs and CWIP in Revenue Requirements

	Annual Budgeted Capital Costs		Cumulative Budgeted Capital Costs		CWIP in Revenue Requirements
	Total No-Hardware	Total w/ Hardware	Total No-Hardware	Total w/ Hardware	
Pre-2016	2.1	2.1	2.1	2.1	
2016	2.7	2.7	4.8	4.8	
2017	8.3	11.4	13.1	16.2	16.4
2018	8.5	10.8	21.6	27.0	28.9
2019	11.6	11.8	33.2	38.8	42.5
2020+	30.3	30.3	63.5	69.1	
Total	63.5	69.1			

Sources: Budgeted Costs from Petition, Attachment 1A, page 19
CWIP in Revenue Requirements from Petition, Attachment 13

The Department requests that the Company confirm in Reply Comments that the CWIP balances shown in Attachment 13 do not include hardware costs, and also explain what is included in those CWIP balances and why they differ from the budgeted costs.

The Department notes that nearly half of the expected non-hardware costs relate to a geospatial information system (GIS) data collection effort the Company stated it needs to undertake in order to develop an adequate model of its distribution system, which will be an important input to its ADMS system. As described on pages 15-16 of Attachment 1A, this data collection effort is expected to take several years, and the bulk of the work is expected to occur in 2020 or later. Additionally, the Company is working with the National Renewable Energy Laboratory (NREL) to determine how much data it needs to collect. Thus it is the Department's understanding that the GIS-related cost estimate is subject to change.

Additionally, in its Response to DOC IR 13, the Company identified some GIS-related costs that were included in its most recent rate case, that it had inadvertently also included in its TCR proposal. The Company produced a revised version of Attachment 4 to its Petition with these additional GIS costs removed from proposed revenue requirements. These revisions are reflected in Table 1 above.

The ADMS is being developed at the total company level, including the Company's Colorado affiliate, Public Service Company of Colorado. Therefore the costs of the ADMS project must be allocated from the total company level to NSPM, and then to the Minnesota Jurisdiction of

NSPM. The Company provided these allocations in response to DOC IR 12.[5] The Company stated that labor and GIS costs are direct assigned to NSPM, and software and hardware costs are allocated based on electric distribution plant balances.

The Company indicated that NSPM's share of costs are allocated between its three state jurisdictions using an allocator called "MN JUR Electric Intangible Composite." Based on that allocator, Minnesota's share of NSPM's costs is 87.3647 percent.

The Department requests that the Company describe in Reply Comments what the "MN JUR Electric Intangible Composite" allocator is, and support its choice to use one allocator to allocate costs from the total company level to NSPM, but a different allocator to divide costs among NSPM's three state jurisdictions.

C. MISO SCHEDULES 26/26A CHARGES (RECB)

1. Net MISO Schedule 26/26A Charges

Minn. Stat. §216B.16, subd. 7b(b)(2) allows utilities providing transmission service to "recover charges incurred under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system. These charges must be reduced or offset by revenues received by the utility and by amounts the utility charges to other regional transmission owners, to the extent those revenues and charges have not been otherwise offset."

As in prior TCR filings, Xcel proposed to continue to recover the net charges it pays other electric utilities through MISO Schedules 26/26A through its TCR. Under Xcel's proposal, it would recover the estimated amount of payments it makes under MISO Schedules 26/26A, net of the estimated revenues it receives under those schedules.

[5] See DOC Attachment 2.

Table 3
NSPM's MISO Schedules 26/26A Expense
($ Millions)

Year	MISO Schedule 26/26A Net Expense	Source
2013	(13.5)	Docket No. E002/M-14-852, Petition, Attachment 4
2014	(28.8)	2015 TCR Docket, Petition, Attachment 4
2015	(20.2)	2015 TCR Docket, Compliance Filing, Attachment 4
2016	(16.1)	Petition
2017	0.9	Petition (in 2015 TCR Docket, f'casted $9.1 million credit)
2018	0.4	Petition
2019	(11.0)	Petition

Note: negative number indicates net revenues, positive numbers indicate net expense

The Department notes that during the period 2013-2016, the Company's revenues from MISO Schedules 26/26A exceeded its expenses, reducing rates for Minnesota Ratepayers. In its Petition, however, the Company projected net expenses in 2017 and 2018. The net expense estimated for 2017 includes charges related to a change in the allowed return on equity at the wholesale level, as discussed below, which may explain some, but not all, of the observed change in MISO Schedule 26/26A.

The Department requests that the Company explain the significant change observed in 2017 and 2018 MISO Schedule 26/26A net revenues, relative to 2013-2016.

In its Response to DOC IR 3, the Company explained that the decrease in net expense from $0.4 million in 2018 to negative $11.0 million in 2019 is due to an increase in expected Schedule 26A revenues associated with a transmission project that is expected to go in service in December 2018.[6]

2. FERC ROE Adjustment

As discussed on pages 15-17 of the Petition, in September 28, 2016, the Federal Energy Regulatory Commission (FERC) issued Opinion 531 revising the return on equity allowed for MISO Transmission Owners down from 12.38 percent to 10.82 percent, including a 50-basis-point adder for being a member of a regional transmission organization. Pursuant to the ROE

[6] See Department Attachment 3.

adjustment, refunds, with interest, were issued to MISO transmission customers for the period Nov. 12, 2013 through Feb. 11, 2015. The refunds were paid by MISO transmission owners in two payments in 2017.

In its Petition, the Company stated that at the Total Company level, as a transmission customer, it received a refund of $7.9 million. However, the Company is both a transmission customer and a transmission owner, and as a transmission owner the Company was assessed a charge of $18.4 million (including interest) to reflect the lower revenues it would have been entitled to had the 10.82 percent ROE been in effect during the refund period.[7] Because the Company is effectively a "net seller" of wholesale transmission service (i.e. its MISO revenues exceed its MISO expenses), and because its ratepayers are credited with net MISO revenues via the TCR, the ROE reduction has a negative impact on ratepayers.

At the Total Company level, Xcel's total revenues were reduced by $18.4 million, and its expenses were reduced by $8.7 million. A portion of the revenue charge and the expense credit relate to transmission service that is reflected in base rates, and Xcel has proposed to not include any revenue charge or expense credit associated with that service in the TCR. The Department agrees that Xcel's approach is reasonable.

Additionally, the Company excluded all accrued interest on the revenue charge and expense credit, which further reduced the impact on ratepayers.[8]

Table 5
Charges and Credits Pursuant to
FERC ROE Adjustment

	Revenue Charge	Expense Credit	Net
Total Company - With Interest			
Total Excluded from TCR	(3.2)	0.1	(3.1)
Total Included in TCR	(15.3)	8.6	(6.7)
Total	(18.4)	8.7	(9.7)
Included in TCR			
Total with Interest	(15.3)	8.6	(6.7)
Accrued Interest	(1.2)	0.7	(0.5)
Total Net of Interest	(14.1)	7.9	(6.2)

[7] See Department Attachment 4.
[8] See Department Attachment 4.

As shown in Table 5, at the Total Company level, the total impact of the ROE refund on Xcel Energy was negative $9.7 million, including interest. For refunds and charges associated with transmission service reflected in the TCR, the net impact was negative $6.7 million, including interest. However, in its response to DOC IR 2, the Company stated that "Interest income or expense is not considered MISO RECB Activity, so it is excluded from the filing." After excluding interest, the net impact falls to negative $6.2 million.

While beneficial to ratepayers in this instance, the Department is concerned that the Company's proposal to exclude accrued interest from its revenue requirements is inconsistent with the approach of including all revenue and expense associated with MISO Schedule 26/26a (and related Schedules). The Department requests that the Company explain more fully in Reply Comments its reasons for excluding accrued interest from its TCR revenue requirements.

D. RATE OF RETURN ON INVESTMENT

As noted above, NSPM requested approval of an ROE of 10.0 percent for use in calculating its revenue requirements in the TCR. The Department disagrees with the Company's proposed ROE, and instead proposes that the Commission authorize an ROE of 8.99 percent. The Department's ROE analysis is included in the ROE Appendix included with these Comments.

The Department further recommends that the Commission require the Company to use the ROE determined in this Docket in all dockets filed by the Company that require an ROE until the Commission issues an order in the Company's next rate case authorizing a different ROE.

E. ALLOCATION OF COSTS

Northern States Power Minnesota and Northern States Power Wisconsin operate as a single, integrated system, and therefore costs are initially calculated at the total system level. The allocation of costs from the total system level to the Minnesota jurisdictional customer groups is a three-step process. First, the Company allocates total system costs between NSPM and NSPW. Second, NSPM allocates its share of total system costs to each of its three state jurisdictions (Minnesota, North Dakota, and South Dakota). Third, the Company allocates its Minnesota jurisdictional costs among its customer classes.

To allocate total system costs between NSPM and NSPW, the Company uses a demand allocator which reflects the sharing of costs between NSPM and NSPW pursuant to its Interchange Agreement. The Interchange Agreement demand allocator, reported on Attachment 10, line 24 or the Petition, is based on 36-month coincident peak demand. NSPM proposed to use allocation factors of 84.2464 percent, and 84.0798 percent, in 2017 and 2018, respectively. The

Company's proposed cost allocation between NSPM and NSPW is consistent with the methodology used in previous TCR filings, and the Department concludes that it is reasonable.

To allocate NSPM's share of total system costs between NSPM's three state jurisdictions, the Company proposed to use demand allocators based on 12-month coincident peak demand, as shown in the Petition, Attachment 10, line 23. The allocator proposed, 87.3461 percent, is consistent with the jurisdictional allocator the Company proposed in its most recent rate case, Docket No. E002/GR-15-826 (the 2016 Rate Case), and is consistent with the allocator the Department used in its Direct Testimony in the 2016 Rate Case which served as the basis for the settlement of that case. The Department concludes that the Company's proposed jurisdictional allocator is reasonable.

To allocate NSPM's Minnesota jurisdictional costs among the Company's various rate classes within the Minnesota jurisdiction, the Company used its D10S allocator from the 2016 Rate Case, which is based on the Company's system peak coincident with the MISO system peak. This approach is consistent with past practice, and the Department concludes that it is reasonable.

1. Recovery From Minnesota Customer Classes and Applicable Recovery Rates

NSPM's Minnesota jurisdictional customer classes include Residential, Commercial Non-Demand, and Demand. The Company proposed to recover costs allocated to its Residential and Non-Demand customers on an energy-only basis (i.e. via a per kWh charge), and to recover costs allocated to its Demand customer class on a demand-only basis (i.e. via a per kW charge). This recovery method is consistent with the method used in prior TCR Rider filings, thus, the Department concludes that it is reasonable.

F. COMPLIANCE FILING, TRUE-UP REPORT, AND TRACKER BALANCES

The Company noted on page 21 of its Petition that in its January 27, 2017 Compliance Filing in the 2015 TCR Docket, the Company reported actual 2016 expenditures and revenues as required by the Commission in that Docket. The Company noted that the 2016 revenue requirement in the instant Petition differs from the revenue requirement reported in its Compliance Filing, for two reasons. First, the Company updated the 12-month CP demand allocator it uses to allocate NSPM's costs between Minnesota, North Dakota, and South Dakota to match the allocator approved in the Company's most recent rate case, Docket No. E002/GR-15-826. Second, the Company revised its RECB amounts to reflect a December 2016 True-Up. The net effect of these two changes was to raise the 2016 revenue requirement from $80.2 million to $80.5 million.

The Department agrees that the first adjustment, to the 12-month CP demand allocator, is reasonable. However, the Department requests that the Company explain in Reply Comments the reason(s) for the December 2016 true-up to its RECB amount.

G. TWO-WAY CARRYING CHARGE

As noted above, the Company requested approval of a two-way carrying charge on tracker balances beginning January 1, 2019 to account for "the potential for a misalignment of the time a rate is effective compared to the revenue requirements intended for recovery."[9] A two-way carrying charge would result in ratepayers paying interest on undercollected balances, and the Company paying interest on overcollected tracker balances. In its response to OAG Information Request (IR) 203, the Company provided an illustrative example of how delays in implementation of updated rate factors can result in significant growth in tracker balances. The Company also stated that if a two-way carrying charge were implemented, "[a]ll parties would have some motivation to match the recovery period with the test period so as to minimize the magnitude of a carrying charge…."

The Commission considered this issue in Docket No. E017/M-13-103, an Otter Tail TCR proceeding. In its March 10, 2014 Order, the Commission stated on page nine:

> In Otter Tail's last renewable energy rider docket, the Commission requested that the Company explain, in its next rider filing of any type, why the inclusion of a carrying charge imposed on a rider tracker account balance is justified. The Company responded to the Commission's request in this docket by stating that a rider reflects either an over- or under-recovery of the tracker balance and the carrying charge provides symmetrical treatment in both circumstances.
>
> Having considered the issue, the Commission will not allow the Company to add a carrying charge to the tracker balance for its transmission cost recovery rider and its renewable resource cost recovery rider. While the Company's observation about symmetrical treatment is true, it does not go to the heart of the issue. As discussed above, the TCR rider and the renewable resource cost recovery rider are extraordinary cost-recovery mechanisms adopted to expedite the construction of critically needed infrastructure.

[9] Petition, at 14.

> They offer unique advantages over traditional ratemaking treatment. For example, they permit cost recovery—including recovery of the authorized rate of return—to begin with construction, instead of when the facilities are placed into service. And both riders permit cost recovery to begin before the facilities' costs have been fully scrutinized in a rate case. The additional advantages of a carrying charge are therefore unnecessary either to ensure fairness or to act as an incentive.
>
> For all these reasons, the Commission will not permit carrying charges on either rider. [footnote omitted]

Based on the Commission's reasoned decision in Docket No. E017/M-13-103, the Department recommends that the Commission deny the Company's request for a two-way carrying charge.

H. ACCUMULATED DEFERRED INCOME TAXES

In the 2015 TCR Docket, as well as several other dockets, the appropriate ratemaking treatment of the Company's accumulated deferred income taxes (ADIT) was a source of controversy and was discussed extensively.[10] Specifically, the Company's position was that it is required to prorate its forecasted ADIT balances when calculating revenue requirements, and that it is not allowed to replace the prorated forecasted ADIT balances with actual non-prorated ADIT balances in the true-up calculation for the period in a subsequent docket. The Department did not agree that the Company was barred from doing this. In the 2015 TCR Docket, this issue was resolved by timing, as the final adjustment factors were not implemented until after the test year, meaning no proration was required. However, the outstanding question of the appropriate ratemaking treatment of ADIT for the purposes of NSPM's TCR Rider remains unanswered.

In the 2015 TCR Docket, the Company proposed to defer this issue to a future proceeding,[11] and that it would, if necessary, submit a request for a private letter ruling (PLR) to the Internal Revenue Service (IRS) for a definitive ruling.

The Commission's January 17, 2017 Order in the 2015 TCR Docket, on page six, stated:

> The Commission concurs with the parties that a ruling from the IRS, specific to Xcel's circumstances, would greatly aid the Commission in resolving the complex tax issues related to ADIT proration.

[10] See, for example, Docket Nos. E002/M-15-805 and G002/M-17-174.
[11] See the Company's September 29, 2016 Response Comments in the 2015 TCR Docket, at 2.

In its August 24, 2017 Order in Docket No. G002/M-17-174, the Commission stated, however:

> At the Commission meeting, the Company stated that it hoped to reach a compromise with the Department regarding the treatment of ADIT, to avoid the need to obtain a PLR, in light of another PLR recently issued.

No PLR has been obtained, and no compromise has been reached.

In its Petition, the Company stated that it included actual ADIT balances for non-forecasted months (through June, 2017), and included prorated forecasted ADIT balances for forecasted months (from July, 2017 through December, 2018).

The Department's position is unchanged from the 2015 TCR Docket. In its April 21, 2016 Comments in that Docket, the Department stated:

> 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.
>
> …
>
> Based on the above, the Department recommends that the Commission require Xcel to replace its forecasted prorated ADIT balances with actual non-prorated ADIT balances in its beginning-of-month and end-of-month average calculations for true-up purposes in future [Transmission Cost Recovery] TCR Rider filings. 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.

The Department recommends that the Commission either (1) allow the Company to include prorated ADIT balances in its forecasted test-year revenue requirement calculations, but require it to replace its forecasted prorated ADIT balances with actual non-prorated ADIT balances in its beginning-of-month and end-of-month average calculations for true-up purposes in future TCR dockets, OR (2) require the Company to implement the adjustment factors, based on actual non-prorated ADIT balances, approved in this Docket on or after January 1, 2019. Doing so would render the rate adjustment factors historical, eliminating the need to prorate ADIT balances.

I. INTERNAL CAPITALIZED COSTS

Consistent with the Commission's decisions in prior TCR proceedings, the Company removed internal capitalized labor costs in its revenue requirements calculations. The Department agrees with this approach.

J. IMPACT OF THE TAX CUT AND JOBS ACT

After the Company filed its Petition, the Tax Cuts and Jobs Act of 2017 (TCJA) was signed into law, reducing the corporate income tax rate from 35.00 percent to 21.00 percent. The TCJA will have a number of impacts on the Company's revenue requirements related to, e.g., tax expense, ADIT balances, and depreciation.

The Department requests that the Company provide in Reply Comments updated revenue requirement calculations that account for the impact of the TCJA.

K. PROPOSED REVISED TARIFF SHEET

The addition of the ADMS project to Xcel's TCR necessitated changes to the TCR tariff language included in the Company's Minnesota Electric Rate Book. The tariff language currently refers only to costs associated with transmission projects. NSPM proposed to modify its tariff language to include references to distribution costs, as shown in Attachment 16 to its Petition.

The Company also deleted a reference to street lighting, which is no longer assigned any costs in the TCR.

The Department has reviewed the Company's proposed changes to its tariff language and concludes that they are reasonable.

III. CONCLUSION

The Department requests that, in Reply Comments, the Company:

- confirm that the CWIP balances shown in Attachment 13 for the AMDS project do not include hardware costs, and also explain what is included in those CWIP balances and why they differ from the budgeted costs;
- describe what the "MN JUR Electric Intangible Composite" allocator is, and support the Company's choice to use different allocators to allocate ADMS costs from the total company level to NSPM, and among NSPM's three state jurisdictions;

- explain the significant change observed in 2017 and 2018 MISO Schedule 26/26A net revenues, relative to 2013-2016;
- explain more fully its reasons for excluding accrued interest associated with the FERC ROE refunds from its TCR revenue requirements;
- explain the reason(s) for the December 2016 true-up to its RECB amount; and
- provide updated revenue requirement calculations that account for the impact of the TCJA.

The Department will provide its recommendations to the Commission after it reviews the information the Company provides in Reply Comments.

/ja

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Xcel Energy
Docket No.: E002/M-17-797
Response To: Department of Commerce Information Request No. 13
Requestor: Craig Addonizio
Date Received: February 26, 2018

Question:
Topic: GIS-Related costs
Reference(s): Bloch and Harkness Direct Testimony in Docket No. E002/GR-15-826

The Direct Testimony of Kelly A. Bloch in the above-referenced rate case, Schedule 2, page 7, identifies approximately $1.0 million per year of "GIS Model Improvements" in 2016, 2017, and 2018. On page 60 of her Direct Testimony, Ms. Bloch stated that the GIS data improvements "lay the groundwork for ADMS" and that "[i]mproving this data is a necessary first step before ADMS can be fully implemented."

The Direct Testimony of David C. Harkness in the above-referenced rate case, Schedule 2, page 5 identifies capital investments in GIS Upgrades of $2.4 million in 2016, and $0.8 million in 2018.

a. Please explain the discrepancies in the GIS amounts identified by Ms. Bloch and Mr. Harkness.
b. Please explain whether the GIS costs identified by Ms. Bloch and Mr. Harkness are "business as usual" costs or if they were expected as a direct result of Xcel's grid modernization efforts.
c. Please explain whether these costs are reflected in Attachment 4A to Xcel's TCR Petition (and therefore removed from the TCR revenue requirements)? If not, please explain why not.

Response:
a. The GIS costs identified by Ms. Bloch and Mr. Harkness are related to separate initiatives. Ms. Bloch's testimony is referring to a project to a GIS data accuracy initiative in preparation for the eventual implementation of ADMS. Mr. Harkness's testimony supports two other projects to upgrade the current GIS platform to the latest software version.

b. The GIS costs identified by Ms. Bloch are part of building the data model required by ADMS, which is part of our grid modernization efforts. The GIS costs identified by Mr. Harkness are "business as usual" upgrades to the GIS system.

c. Because the GIS projects in Mr. Harkness's testimony are not related to the ADMS project, they are not included in the ADMS costs in the TCR petition. However, we should have calculated in Attachment 4A of the initial TCR Petition the removal of the GIS Model Improvements project costs identified by Ms. Bloch. As we refined the scope of our overall Advanced Grid Intelligence and Security (AGIS) initiative, we grouped the various components to better track them. In reviewing the accounting strings and project mapping to respond to this information request, we discovered that the original GIS Model Improvements project parent (11813718 from the rate case, shown in Schedule 2 to Ms. Bloch's Direct Testimony) was incorrectly mapped, so we had not identified it for removal from the TCR Rider.

   We provide Attachments A and B to this response to detail the effects of the GIS Model Improvements project removal on the TCR Rider revenue requirements. Attachment A provides the details of the GIS Model Improvements project parent, similar to our Attachment 4A to our TCR Petition. Attachment B updates the TCR Rider Tracker to reflect the combined removal of the two project parents included in the rate case. See line 13 specifically. The effect of the removal of the GIS Model Improvement parent is a reduction of $1.113 million to the requested TCR revenue requirement for 2017 and 2018 combined. We are confident all other costs have been properly assigned to ADMS and the TCR revenue requirement.

Preparer:	Tony Russeth	Shari Cardille
Title:	Manager, Financial Planning and Reporting	Principal Rate Analyst
Department:	Financial Performance and Reporting	Revenue Requirements North
Telephone:	612-330-5933	612-330-1974
Date:	March 8, 2018	

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

		Total Company			MN Jurisdiction		
	Rate Analysis	2017	2018	2019	2017	2018	2019
1	Average Balances:						
2	Plant Investment	1,993	2,989	3,736	1,741	2,611	3,264
3	Depreciation Reserve	401	888	1,553	350	776	1,356
4	CWIP	-	-	-	-	-	-
5	Accumulated Deferred Taxes	356	493	534	311	430	466
6	Average Rate Base = line 2 - line 3 + line 4 - line 5	1,236	1,608	1,649	1,080	1,405	1,441
7							
8	Revenues:						
9	Interchange Agreement offset = -line 40 x line 52 x line 53				-	-	-
10							
11	Expenses:						
12	Book Depreciation	393	592	744	343	517	650
13	Annual Deferred Tax	165	109	(27)	144	96	(24)
14	ITC Flow Thru	-	-	-	-	-	-
15	Property Taxes	-	-	-	-	-	-
16	subtotal expense = lines 12 thru 15	558	702	718	487	613	627
17							
18	Tax Preference Items:						
19	Tax Depreciation & Removal Expense	795	859	678	694	750	592
20	Tax Credits (enter as negative)	-	-	-	-	-	-
21	Avoided Tax Interest	-	-	-	-	-	-
22					-	-	-
23	AFUDC	1	1	1	1	1	1
24							
25	Returns:						
26	Debt Return = line 6 x (line 44 + line 45)	28	36	37	24	32	32
27	Equity Return = line 6 x (line 46 + line 47)	60	78	80	52	68	70
28							
29	Tax Calculations:						
30	Equity Return = line 27	60	78	80	52	68	70
31	Taxable Expenses = lines 12 thru 14	558	702	718	487	613	627
32	plus Tax Additions = line 21	-	-	-	-	-	-
33	less Tax Deductions = (line 19 + line 23)	(796)	(860)	(678)	(696)	(751)	(592)
34	subtotal	(179)	(81)	119	(157)	(71)	104
35	Tax gross-up factor = t / (1-t) from line 50	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611
36	Current Income Tax Requirement = line 34 x line 35	(126)	(57)	84	(110)	(50)	73
37	Tax Credit Revenue Requirement = line 20 x line 35 + line 20	-	-	-	-	-	-
38	Total Current Tax Revenue Requirement = line 36+ line 37	(126)	(57)	84	(110)	(50)	73
39							
40	Total Capital Revenue Requirements	517	757	918	452	661	801
41	= line 16 + line 26 + line 27 + line 38 - line 23 + line 9						
42	O&M Expense	-	-	-	-	-	-
43	Total Revenue Requirements	517	757	918	452	661	801
	Capital Structure	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**
44	**Long Term Debt**	**2.2100%**	**2.2100%**	**2.1800%**	**2.2100%**	**2.2100%**	**2.1800%**
45	**Short Term Debt**	**0.0500%**	**0.0500%**	**0.0700%**	**0.0500%**	**0.0500%**	**0.0700%**
46	**Preferred Stock**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
47	**Common Equity**	**4.8300%**	**4.8300%**	**4.8300%**	**4.8300%**	**4.8300%**	**4.8300%**
48	**Required Rate of Return**	**7.0900%**	**7.0900%**	**7.0800%**	**7.0900%**	**7.0900%**	**7.0800%**
49	**PT Rate**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
50	**Tax Rate (MN)**	**41.3700%**	**41.3700%**	**41.3700%**	**41.3700%**	**41.3700%**	**41.3700%**
51	**MN JUR Energy**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**
52	**MN JUR Electric Intangible Composite**	**87.3467%**	**87.3467%**	**87.3467%**	**87.3467%**	**87.3467%**	**87.3467%**
53	**IA Demand**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**

Annual Tracker Summary

Line No:	Amounts in dollars	2016 Actual	2017 Mixed	2018 Forecast	2019 Forecast
1	ADMS	-	961,655	2,658,840	3,758,091
2	Big Stone-Brookings	2,035,350	3,639,881	5,875,499	5,693,521
3	CAPX2020 Brookings	40,530,371	39,876,460	38,797,148	37,716,564
4	CAPX2020 - La Crosse Local	4,725,929	5,209,627	5,185,816	5,069,319
5	CAPX2020 - La Crosse MISO	6,916,302	6,683,364	6,441,097	6,259,007
6	CAPX2020 - La Crosse MISO - WI	12,411,998	12,200,382	11,922,824	11,580,399
7	CAPX2020 Fargo	18,441,337	18,212,210	17,610,096	17,049,344
8	LaCrosse - Madison	1,900,767	5,751,456	10,007,548	15,388,885
9	MISO RECB Sch.26/26a	(16,092,283)	941,551	368,171	(10,957,930)
10	RES Study	-	298,509	-	-
11	ADIT Pro-Rate	-	99,981	627,974	241,014
12	Transmission Projects	70,869,772	93,875,075	99,495,014	91,798,213
13	Revenue Requirement in Base Rates (ADMS)*	-	(477,000)	(701,000)	(1,937,000)
14	TCR True-up Carryover	9,656,056	1,393,750	9,642,865	(1,281,768)
15	**Revenue Requirement (RR)**	**80,525,828**	**94,791,825**	**108,436,879**	**88,579,445**
16	Revenue Collections (RC)	79,132,079	85,148,960	109,718,647	88,579,445
17	**Carry Over Balance**	1,393,750	9,642,865	(1,281,768)	(0)

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Xcel Energy
Docket No.: E002/M-17-797
Response To: Department of Commerce Information Request No. 12
Requestor: Craig Addonizio
Date Received: February 26, 2018

Question:
Topic: Cost Allocations
Reference(s): Petition, page 8, and Attachment 1A pages 19 and 21

a. Table 1 on page 19 of Attachment 1A to the Petition provides a high level breakdown of the projected $69.1 million in ADMS capital costs by year. Please provide the same data at the Total Company level showing the yearly breakdown of the projected $208.9 million in Total-Company costs (as stated on page 8 of the Petition).

b. Please provide detailed schedule(s) showing the allocation of the Total-Company amount of $208.9 million to the Minnesota Jurisdiction. For each type of cost being allocated, please clearly identify the allocator being used.

Response:

a. Please see Attachment A to this response showing the yearly breakdown of the projected $208.9 million in Total-Company costs on lines 1 through 8.

b. Please see Attachment A to this response for the detailed schedule showing the allocation of the Total-Company amount of $208.9 million to the Minnesota Jurisdiction.

Preparer: Tony Russeth
Title: Manager, Financial Planning and Reporting
Department: Financial Performance and Reporting
Telephone: 612-330-5933
Date: March 8, 2018

ADMS Capital Budget Summary - Xcel Energy Total Company
(Dollars in Millions)

1	**Xcel**	**Pre-2016**	**2016**	**2017**	**2018**	**2019**	**2020+**	**Total**
2	**Labor**	6.8	7.4	19.4	21.1	17.9	10.1	82.6
3	**Software**	0	0	5.9	3.9	0	0	9.9
4	**GIS**	0	0	3.2	9	9.9	75.6	97.6
5	**Sub-total**	6.8	7.4	28.5	34	27.8	85.7	190.1
6								
7	**Hardware**	0	1.3	9.4	7.2	0.9	0	18.8
8	**TOTAL**	6.8	8.7	37.9	41.2	28.7	85.7	208.9

ADMS Capital Budget Summary - NSPM Total Company
(Dollars in Millions)

9	**NSPM**	**Pre-2016**	**2016**	**2017**	**2018**	**2019**	**2020+**	**Total**
10	**Labor (1)**	2.5	3.1	7.2	7.8	11.6	1.6	33.7
11	**Software (2)**	0.0	0.0	2.2	1.4	0.0	0.0	3.6
12	**GIS (3)**	0.0	0.0	0.2	0.5	1.8	33.1	35.5
13	**Sub-total**	2.5	3.1	9.5	9.7	13.3	34.7	72.8
14								
15	**Hardware (2)**	0.0	0.0	3.5	2.7	0.2	0.0	6.4
16	**TOTAL**	2.5	3.1	13.0	12.4	13.6	34.7	79.2

17 (1) Labor work Direct Assigned to NSPM
18 (2) Software and Hardware contain an allocation from Xcel to NSPM with the exception of 2016 Hardware
19 which is 100% PSCo and 2019 has no PSCo amount
20 NSPM Allocation = 0.3700 based on Electric Distribution Plant
21 (3) GIS work Direct Assigned to NSPM

ADMS Capital Budget Summary - NSPM Minnesota Jurisdiction
(Dollars in Millions)

22	**MN Jurisdiction**	**Pre-2016**	**2016**	**2017**	**2018**	**2019**	**2020+**	**Total**
23	**Labor**	2.1	2.7	6.3	6.8	10.1	1.4	29.4
24	**Software**	0.0	0.0	1.9	1.3	0.0	0.0	3.2
25	**GIS**	0.0	0.0	0.1	0.4	1.5	28.9	31.0
26	**Sub-total**	2.1	2.7	8.3	8.5	11.6	30.3	63.6
27								
28	**Hardware**	0.0	0.0	3.0	2.3	0.2	0.0	5.6
29	**TOTAL**	2.1	2.7	11.4	10.8	11.9	30.3	69.1

30 MN JUR Electric Intangible Composite = 0.873467

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Xcel Energy			
Docket No.:	E002/M-17-797		
Response To:	Department of Commerce	Information Request No.	3
Requestor:	Craig Addonizio		
Date Received:	February 26, 2018		

Question:
Topic: MISO Sch. 26 and 26a billings
Reference(s): Petition, Attachment 12

a. Please provide 2016 Schedule 26 and 26a revenues and expense by month.

b. Please provide all MISO bills for the months in which ROE refunds were dispersed, and reconcile the bills with the monthly amounts provided in response to part (a) of this information request.

c. Please explain generally why Xcel expects such a large change in 2019 Schedule 26/26a net revenue requirements, relative to 2018 ($11.0 million credit for 2019 versus $0.4 million expense in 2018).

Response:

a.) Please see Attachment A to this response for the 2016 Schedule 26 and 26a revenues and expense by month.

b.) ROE refunds were dispersed by MISO in 2017. MISO completed the refunds in two phases: (1) resettlement of the refund period by adjusting the original billing rates for the ROE change, completed in January 2017; and (2) resettlement of formula rate true-ups impacted by the ROE change, which MISO completed in May 2017. To fully reconcile the refund amounts, one would need to examine settlement files from MISO for the months of January, February, May and June 2017. Each month, eight settlement files are produced by MISO. Due to the complexity and voluminous nature of these files, we have not provided them at this time. See Attachments B through I to our response to Information Request No. DOC-2 for examples of this type of file. The Company is prepared to meet with the Department to walk through these files and be available for questions.

By way of background, the RECB monthly amounts included in the petition are accounting estimates booked based on preliminary information provided by MISO during NSP's month-end close cycle. Final data is provided to NSP by MISO after the close cycle has ended, and any differences between the preliminary data and the final data is booked by NSP in the following month, and captured in the following month's RECB amounts.

c.) The variance from 2018 to 2019 is largely due to increased Schedule 26a revenues in 2019 related to MTEP Project Number 3127, which was approved within the MTEP 11 process. As the expected in-service date for this project is December 2018, NSP forecasted revenue for only one month of 2018, compared to forecasted revenue for 12 months of 2019.

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Title:	Principal Rate Analyst	Utility Accounting Financial Consultant
Department:	Revenue Requirements North	Transmission Accounting
Telephone:	612-330-1974	303-294-2129
Date:	March 8, 2018	

Regional Expansion Criteria and Benefits

Amounts in dollars

Line No.		Jan-16 Actual	Feb-16 Actual	Mar-16 Actual	Apr-16 Actual	May-16 Actual	Jun-16 Actual	Jul-16 Actual	Aug-16 Actual	Sep-16 Actual	Oct-16 Actual	Nov-16 Actual	Dec-16 Actual	**2016 Actual**
	Revenue													
1	Schedule 26	7,314,180	6,696,838	6,814,322	6,195,277	7,011,871	8,370,493	9,247,551	8,090,624	8,272,898	6,399,088	5,772,525	8,665,749	88,851,417
2	Schedule 26(a)	5,888,350	5,457,632	5,259,019	4,646,720	4,932,207	5,353,853	6,006,401	5,780,408	5,409,469	4,482,327	4,445,048	3,822,004	61,483,437
3	Total Revenue	13,202,529	12,154,470	12,073,341	10,841,997	11,944,078	13,724,346	15,253,952	13,871,032	13,682,368	10,881,415	10,217,573	12,487,753	150,334,855
4														
5														
6	**Expense**													
7	Schedule 26	6,584,416	5,939,180	5,873,218	5,691,989	6,909,540	8,012,698	9,482,677	9,531,065	7,368,463	5,941,208	5,688,454	7,391,698	84,414,607
8	Schedule 26(a)	4,094,270	3,887,620	3,865,705	3,435,062	3,766,960	3,846,611	4,457,693	4,225,062	3,671,873	3,057,146	3,126,969	2,587,602	44,022,575
9	Total Expense	10,678,686	9,826,800	9,738,923	9,127,051	10,676,500	11,859,309	13,940,370	13,756,127	11,040,337	8,998,354	8,815,424	9,979,301	128,437,182
10														
11														
12	Total	(2,523,843)	(2,327,671)	(2,334,417)	(1,714,946)	(1,267,578)	(1,865,037)	(1,313,582)	(114,905)	(2,642,031)	(1,883,061)	(1,402,149)	(2,508,452)	(21,897,673)
13	Demand Allocator - State of MN Jur.	73.4886%	73.4886%	73.4886%	73.4886%	73.4886%	73.4886%	73.4886%	73.4886%	73.4886%	73.4886%	73.4886%	73.4886%	73.4886%
14	RECB Revenue Requirement	(1,854,736)	(1,710,572)	(1,715,530)	(1,260,289)	(931,525)	(1,370,589)	(965,333)	(84,442)	(1,941,590)	(1,383,834)	(1,030,419)	(1,843,425)	(16,092,283)
15	RECB in Base Rates	-	-	-	-	-	-	-	-	-	-	-	-	-
16	**Net RECB Revenue Requirements**	**(1,854,736)**	**(1,710,572)**	**(1,715,530)**	**(1,260,289)**	**(931,525)**	**(1,370,589)**	**(965,333)**	**(84,442)**	**(1,941,590)**	**(1,383,834)**	**(1,030,419)**	**(1,843,425)**	**(16,092,283)**

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Xcel Energy
Docket No.: E002/M-17-797
Response To: Department of Commerce Information Request No. 2
Requestor: Craig Addonizio
Date Received: February 26, 2018

Question:
Topic: MISO ROE Refund
Reference(s): Petition, page 16; MISO July 28, 2017 Refund Report in FERC Docket Nos. EL14-12-002 and ER17-215-000

The July 28, 2017 MISO Filing in the above-referenced FERC dockets includes two attachments titled "Phase I Refund Report" and "Phase II Refund Report."

a. Please identify all Xcel-related entities listed in the Phase I and II Refund Reports and explain exactly what each entity is, and how it relates to Xcel's Minnesota operations.
b. The Phase I and II Refund Reports appear to include two different groupings of utilities. NSPP and NSPX appear to be part of one group, and NSP appears to be part of the second group. Please explain what the two different groupings of utilities are.
c. Please reconcile the $7.9 million amount reported on page 16 of the Petition with the Phase I and II Refund Reports. For any charge, refund, or interest amount associated with an Xcel-related entity reported in the Phase I and II Refund Reports, please explain why it was or was not credited to ratepayers.
d. Please explain Xcel's understanding of how the charges, refunds, and interest amounts listed in the Refund Reports were calculated, and explain whether Xcel played any role in determining those amounts.
e. Please explain whether MISO provided any supporting workpapers or other materials showing how the charges, refunds, and interest amounts were determined. If so, please provide them, or provide a cite where the Department can access them.

Response:
a. The MISO Refund Reports list Xcel Energy's three market participants in MISO, which include the following:
    - NSP – Xcel Energy's Transmission Owner in the MISO market ;

- NSPP – Xcel Energy's Transmission Customer in the MISO market; and
- NSPX – Xcel Energy's Transmission Customer for Proprietary Trading in the MISO market.

b. The two different groupings included in the MISO Refund Reports reflect Transmission Owners (NSP) and Transmission Customers (NSPP and NSPX).

c. The amount disclosed on page 16 of the Petition, encompasses the reduction in expenses incurred by NSPP, it did not include the reduction in revenue earned by NSP.

The Phase I and Phase II settlements encompassed both the reductions in revenue and expenses for Schedule 26 and 26A. NSP Revenues were reduced by approximately $14.1 million and NSPP expenses were reduced by approximately $7.9 million, respectively. See Attachment A to this response for a reconciliation of these amounts to the MISO Refund Reports. Interest income or expense is not considered MISO RECB Activity, so it is excluded from the filing.

All refunds and charges associated with the 2017 ROE settlement as listed in the Phase I and Phase II Refund Reports have been incorporated into the 2017 RECB amounts presented in the Petition. There will be no further impacts to the RECB amounts resulting from the ROE settlements that occurred in January and May 2017. The net result of the refunds is an increase in RECB amounts because the reduction in revenues was greater than the reduction in expenses.

d. The refund amounts reflected in the Phase I and Phase II Refund Reports were calculated by MISO. Xcel Energy did not play a role in determining these amounts.

The Phase I Refund Report reflects the refund due to the impact of the lower ROE (10.82% vs 12.38%) on the projected 2013, 2014 and 2015 rates (Schedule 7, 8, 9, 26 and 26-A) billed from November 12, 2013 through February 11, 2015. The change in each rate for each of these months was applied to each customer's final load for that month.

The Phase II Refund Report reflects the change in the ROE on the 2013, 2014 and 2015 actual formula rate true-up calculations for the MISO Transmission Owners.

e. See the Phase I and Phase II settlement files provided by MISO in the following live Excel attachments included with this response:
   - Att B - mc004nsp_2017010100est35.xlxs
     – Phase I Settlements for NSP charges
   - Att C - mr005nsp_2017010100est35.xlsx
     – Phase I Settlements for NSP refunds
   - Att D - mc004nspp_2017010100est35.xlsx
     – Phase I Settlements for NSPP charges
   - Att E – mr005nspp_2017010100est35.xlsx
     – Phase I Settlements for NSPP refunds
   - Att F – mc004nsp_2017050100est35.xlsx
     – Phase II Settlements for NSP charges
   - Att G – mr005nsp_2017050100est35.xlsx
     – Phase II Settlements for NSP refunds
   - Att H – mc004nspp_2017050100est35.xlsx
     – Phase II Settlements for NSPP charges
   - Att I - mr005nspp – 2017050100est35.xlsx
     – Phase II Settlements for NSPP refunds

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MISO Refund Reconciliation

Refund Report - Phase I				
Xcel Entity	**Charge**	**Refund**	**Net**	
NSP	17,895,896	0	(17,895,896)	
NSPP	10,817	8,533,351	8,522,534	
NSPX	78	68,708	68,630	*not included in TCR*

Refund Report - Phase II				
Xcel Entity	**Charge**	**Refund**	**Net**	
NSP	784,956	257,403	(527,553)	
NSPP	264,499	419,100	154,601	
NSPX	10,307	1,991	(8,316)	*not included in TCR*

Total Refund - Phase I + Phase II				
Xcel Entity	**Charge**	**Refund**	**Net**	
NSP	18,680,852	257,403	(18,423,449)	see **Figure A**
NSPP	275,316	8,952,451	8,677,134	see **Figure B**
NSPX	10,385	70,699	60,314	*not included in TCR*

Figure A:

Revenue Category	Amount	TCR Impact	Interest	TCR Impact - Net of Interest	
Schedule 7	(761,182)	-		-	
Schedule 8	(85,476)	-		-	
Schedule 9	(2,309,569)	-		-	
Schedule 26	(7,611,391)	(7,611,391)	(626,774)	(6,984,617)	
Schedule 37	(86,075)	(86,075)	(6,892)	(79,183)	
Schedule 38	(139,783)	(139,783)	(11,218)	(128,565)	
Schedule 26-A	(7,429,947)	(7,429,947)	(551,503)	(6,878,444)	
Refund Report Total	**(18,423,424)**	(15,267,197)	(1,196,387)	**(14,070,809)**	**Reduction in Revenue Earned**

Figure B:

Expense Category	Amount	TCR Impact	Interest	TCR Impact - Net of Interest	
Schedule 7	6,337	-		-	
Schedule 9	85,132	-		-	
Schedule 26	6,023,727	6,023,727	485,882	5,537,845	
Schedule 26-A	2,561,711	2,561,711	188,828	2,372,883	
Schedule 45	227	-		-	
Refund Report Total	**8,677,134**	8,585,438	674,710	**7,910,728**	**Reduction in Expenses Due**

ROE Appendix

Docket No. E002/M-17-797

I. BACKGROUND AND PURPOSE

In Northern State Power Company's (NSPM or the Company) most recent rate case, Docket No. E002/GR-15-826 (the 2016 Rate Case), the Commission approved a settlement agreement (Settlement) that allowed NSPM to "represent its authorized [return on equity] as nine and two-tenths percent (9.20%) for settlement purposes *in this rate case Proceeding*" (*emphasis added*).[1] In its Order approving the Settlement, the Commission also made clear that the 9.20 percent return on equity (ROE) NSPM was authorized to represent was not binding on future proceedings that involve ROE, stating:

> Because the Settlement does not prevent any party from contesting the ROE when it is applied in rider dockets or other proceedings, if future circumstances suggest that a lower ROE is appropriate in other contexts, parties will be free to assert an alternative ROE at that time.[2]

In its transmission cost recovery (TCR) Petition in the instant Docket, NSPM included an updated analysis of its cost of equity performed by Concentric Energy Advisors, Inc., in Attachment 15 to its TCR Petition (the Concentric Report). Based on that analysis, the Company requested an ROE of 10.0 percent.

The Department also conducted a new ROE analysis, and recommends that the Commission approve an ROE of 8.99 percent. Additionally, the Department recommends that the ROE established in this Docket be used in all proceedings that require an ROE for NSPM's electric operations until NSPM concludes its next rate case, at which time a new ROE would be set.

II. DETERMINATION OF THE COST OF COMMON EQUITY FOR NSPM

A. THE CONCEPT OF A FAIR RATE OF RETURN

In a competitive environment, the forces of supply and demand interact to determine prices and incomes in such a way that resources are allocated to produce an optimal mix of goods and services. This outcome is said to be economically efficient. However, for an economically efficient outcome to be reached, certain conditions must be met, and when they are not met, the forces of supply and demand will not produce the socially desired efficient outcome.
In the case of public utilities, the conditions necessary for competition to yield an efficient outcome are not met, and therefore the role normally assumed by competition is assumed by

[1] See August 16, 2016 Stipulation of Settlement in the 2016 Rate Case, at 6-7.
[2] Commission's June 12, 2017 FINDINGS OF FACT, CONCLUSIONS, AND ORDER in the 2016 Rate Case, page 22.

regulatory agencies, which must ensure that public utilities provide an appropriate supply of satisfactory services at reasonable rates. To provide these services at reasonable rates the utility must be able to compete successfully for necessary funds in the capital markets. To attract these funds the utility must earn enough to offer competitive returns to investors. Thus, a fair return is one that enables the utility to attract sufficient capital, at reasonable terms. A fair rate of return, as required by Minnesota Statutes section 216B.16, subdivision 6, is the rate that, when multiplied by the rate base, will give the utility a reasonable return on its total investment.

The Bluefield and Hope cases (*Bluefield Water Works & Improvement Co. vs. Pub. Serv. Comm'n of W. Virginia, 262 U.S. 679 (1923)* and *Fed. Power Comm'n, vs. Hope Natural Gas Co., 320 U.S. 591 (1944)*) set for the following guidelines for determining a fair rate of return on common equity capital for a rate-regulated utility:

- The rate of return should be sufficient to enable the regulated company to maintain its credit and financial integrity.
- The rate of return should be sufficient to enable the utility to attract capital.
- The rate of return should be commensurate with returns being earned on other investments having equivalent risks.

B. THE METHODS USED TO DETERMINE THE COST OF COMMON EQUITY CAPITAL

Investors are faced with many investment opportunities in the financial markets. To attract investors, Xcel must pay its equity investors a return similar to the equity return that investors expect to earn on investments of comparable risk. This rate of return is the cost of equity capital to NSPM.

Returns accrue to shareholders in the form of dividends paid by the Company. When investors buy the common stock of a utility, they acquire the right to share any dividends that the company may declare in the future. Investors form certain expectations about future dividends based on a company's past and current performance, the company's prospects for future growth, and investors' perceptions of the current and future economic environment. However, investors do not know with certainty what dividends a company will pay in the future and recognize that there is a risk that future dividends will be lower than expected. They also understand that dividends may be higher than expected.

The Discounted Cash Flow (DCF) model postulates that the current price of a stock is equal to the present value of all expected future dividends, discounted by the appropriate rate of return that reflects the uncertainty surrounding the future stream of dividends. It is a fair, market-oriented method that uses current, relevant information to allow Xcel to compete sufficiently and fairly in the capital markets.

The DCF model can be expressed mathematically as:

$$P = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \ldots + \frac{D_\infty}{(1+k)^\infty} \qquad \text{[Eq. 1]}$$

where P is the current stock price; D_1 is the expected dividend at the end of period one, D_2 is the expected dividend at the end of period two, etc.; and k, the discount rate, is the rate of return that the average investor requires as compensation for the risks associated with owning the stock, known as the cost of equity.

In the special case that dividends are expected to grow at a constant rate over time, known as the “constant growth DCF”, Equation 1 above can be rewritten above as:

$$P = \frac{D_0(1+g)}{(1+k)} + \frac{D_0(1+g)^2}{(1+k)^2} + \frac{D_0(1+g)^3}{(1+k)^3} + \ldots + \frac{D_0(1+g)^\infty}{(1+k)^\infty} \qquad \text{[Eq. 2]}$$

where D_1 is the expected dividend at the end of period one, and g is the constant growth rate at which dividends are expected to grow. Equation 2 is an infinite geometric series which, as long as the growth rate g is less than the cost of equity k, can be solved for, algebraically rearranged, and expressed as:

$$k = \frac{D_1}{P} + g \qquad \text{[Eq. 3]}$$

In other words, Equation 3 states that the cost of equity is equal to the sum of a stock’s expected dividend yield and its expected growth rate. While the cost of equity cannot be observed directly, with estimates of a stock’s expected dividend yield (in one year) and its dividend growth rate, the cost of equity can be estimated using Equation 3.

Equation 2 above can also be modified to accommodate two growth rates. The Department uses the “two-growth DCF,” which assumes that dividends grow at one rate for five years, and then grow at a second, sustainable rate in perpetuity, using the following DCF equation:

$$P = \frac{D_1}{(1+k)} + \frac{D_1(1+g)}{(1+k)^2} + \frac{D_1(1+g)^2}{(1+k)^3} + \frac{D_1(1+g)^3}{(1+k)^4} + \frac{D_1(1+g)^4}{(1+k)^5} +$$

$$\frac{D_1(1+g_1)^4(1+g_2)}{(k-g_2)} \times \frac{1}{(1+k)^5} \qquad \text{[Eq. 4]}$$

Additionally, the Department used the Capital Asset Pricing Model (CAPM) as a check on the reasonableness of its DCF analyses. The CAPM is described in greater detail below.

C. SELECTION OF THE DOC PROXY GROUPS

NSPM is a wholly-owned subsidiary of Xcel Energy, Inc. (Xcel Energy). As such, NSPM is not publicly traded on any of the stock exchanges, and therefore, cannot be analyzed directly with a DCF analysis. It is a well-accepted financial principal that companies with similar investment risks are expected to have similar costs of equity. Therefore, when a company's stock is not publicly traded and cannot be analyzed directly with a DCF analysis, an alternative is to perform a DCF analysis on a group (or groups) of proxy companies with comparable investment risk. In order to determine a reasonable return on equity for NSPM, the Department developed two proxy groups (the DOC Proxy Groups) of companies that pose risks to equity investors similar to the risks NSPM poses.

The Department began the screening process for its first proxy group (the Electric Proxy Group, or EPG) by running a search in the Research Insight database for companies that have a Standard Industrial Classification (SIC) code of 4911: Electric Services, and that are traded on one of the major stock exchanges.

SIC code 4911: Electric Services is assigned to companies engaged in the generation, transmission, and/or distribution of electric energy for sale. Limiting the comparison to companies with an SIC code of 4911 ensures that the companies in the proxy group will operate in the same line of business as NSPM, and thus may have business risks similar to the business risks of the Company. One of the data inputs required to perform a DCF analysis is stock price.

It is therefore necessary to select companies with publicly traded stock, which ensures that the companies' stock prices will be publicly available and set by market forces.

The Department began the screening process for its second proxy group (the Combination Proxy Group, or CPG) by running a second search in the Research Insight database for companies that have an SIC code of 4931: Electric and Other Services Combined, and that are traded on one of the stock exchanges. SIC code 4931: Electric and Other Services Combined is assigned to companies primarily engaged in providing electric services in combination with other services: with electric services as the major part though less than 95 percent of the total.

While these companies provide services other than electric services, because they are primarily engaged in the provision of electric services, they may have business risks similar to the business risks of the Company.[3]

From each of these two lists, the Department eliminated companies that have a Standard & Poor's (S&P) credit rating outside the range of BBB to A+ (or are not rated by S&P). As noted on page 15 of the Concentric Report, NSPM has an S&P corporate rating of A-. Companies that have credit ratings similar to NSPM may have comparable risk profiles and are therefore suitable for inclusion in the EPG and the CPG, while companies with credit ratings that are significantly higher or lower than NSPM's may have different risk profiles that render them unsuitable for inclusion in the proxy groups. The range of credit ratings I used to screen utilities, BBB to A+, is two steps above and below NSPM's credit rating of A-.

The Department also eliminated companies that:

- are incorporated outside of the U.S.;
- are not covered by the investor service Value Line and at least one additional investor service, either Zacks Investment Research or Thomson Financial;
- do not pay consistent dividends;
- are known to be involved in merger or acquisition activity;
- receive less than 60 percent of their operating income from regulated electric operations; and
- are not vertically integrated or generate less than 25 percent of their sales from owned generation.

Table 1 presents the EPG and CPG that resulted from this screening process.[4]

Table 1
DOC Proxy Groups

EPG		**CPG**	
Company	Ticker	Company	Ticker
AMERICAN ELECTRIC POWER CO	AEP	ALLETE INC	ALE
EL PASO ELECTRIC CO	EE	ALLIANT ENERGY CORP	LNT
IDACORP INC	IDA	CMS ENERGY CORP	CMS
NEXTERA ENERGY INC	NEE	DTE ENERGY CO	DTE
OTTER TAIL CORP	OTTR	DUKE ENERGY CORP	DUK
PINNACLE WEST CAPITAL CORP	PNW	NORTHWESTERN CORP	NWE
PNM RESOURCES INC	PNM	OGE ENERGY CORP	OGE
PORTLAND GENERAL ELECTRIC CO	POR		

[3] Xcel Energy, Inc., NSPM's parent, was included in the results of that search. The Department excluded Xcel from its CPG in order to avoid issues of circularity.
[4] See ROE Attachments 1 and 2.

D. COST OF EQUITY ESTIMATION

1. Constant Growth DCF Analysis

As described above, under the assumptions of the constant growth DCF, a company's cost of equity k can be expressed as the sum of a stock's expected dividend yield and its expected growth rate:

$$k = \frac{D_1}{P} + g \qquad \text{[Eq. 3]}$$

A company's dividend yield, the first term in Equation 3, can be estimated using its current stock price, P, which is directly observable, its most recent dividend $D_{1,}$ which is also directly observable, and the company's expected growth rate. Expected growth rates cannot be observed in advance and, therefore, the DCF method relies on estimates of future growth rates.

For each company in the DOC Proxy Groups, estimates of each member's expected growth rate, g, the second term in Equation 3, can be sourced from reputable investment research services. The Department used projected earnings per share growth rates (EPS) provided by Zacks Investment Research (Zacks), a respected investor service; Value Line, another widely used investment service; and Thomson's First Call Consensus (Thomson) long-term earnings growth rate estimates.[5]

For both of my DCF analyses, I estimated the cost of equity for each member of the DOC Proxy Group using the average of the three growth rates, the highest of the three growth rates, and the lowest of the three growth rates.

The dividend yield in Equation 3 is equal to the expected dividend at the beginning of the next period (year) divided by the current price (i.e. D_1/P_0). Thus, an estimate of this dividend yield requires an estimate of the expected dividend at the beginning of the next year, and an estimate of the current stock price. The DCF model assumes that dividends are paid once per period (year). The dividend yield in Equation 3, above, is calculated as the expected annual dividend in the next period (D_1) divided by the current stock price (P_0), and thus requires an estimate of each company's annual dividend to be paid one year from now. However, companies generally pay quarterly dividends. To estimate the current level of each company's annual dividend, I annualized the most recent quarterly dividend by multiplying it by four.

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[5] The Department uses projected earnings growth rates, rather than dividend growth rates, because in the long run, dividend growth is driven by earnings growth, and also because academic studies have shown earnings growth rates to be the best predictor of stock prices. See Hearing Exhibit 803 at 17 in the 2016 Rate Case for a fuller discussion of the use of earnings growth rates in DCF analyses.

Additionally, companies increase their dividends in different quarters during the year. The companies in the DOC Proxy Groups may increase their dividends during any of the next four quarters. Some companies will increase their dividends in the first or second quarters, and others will increase it during the third or fourth quarters. Thus, it is reasonable to estimate each company's expected annual dividend in the next period by assuming that two dividends will be paid at the current level and two will be paid at an increased level. I therefore calculated the expected dividend in the next period as:

$$D_1 = D_0(1+0.5xg)$$

Because share prices can be volatile in the short run, it is desirable to use an average share price of a period of time long enough to avoid short-term aberrations in the capital market. However, a share's price at any point of time in the past will necessarily fail to reflect any news or information arising after that point in time that may materially affect the share price. Thus, the period of time should not be too long in order to ensure that the measure of price used to calculate the expected dividend yield appropriately reflects all relevant publicly available information. In order to balance these competing pressures, for purposes of calculating each company's expected dividend yield, the Department calculated share price as the average of the closing price over the 30 trading days, meaning 30 data points, ending March 20, 2018.

The results of the Department's constant growth DCF analyses are summarized in Table 2.

Table 2
Summary of Constant Growth DCF Results

Model	Mean Low ROE	Mean ROE	Mean High ROE
EPG	8.25%	8.96%	9.85%
CPG	8.33%	9.29%	10.13%

ROE Attachments 3 and 7

The Department notes that these results include a flotation cost adjustment, as described below.

2. Two-Growth DCF Analysis

The growth rate estimates from Zacks, Value Line, and Thomson are all five-year growth projections and may not be reasonable to use as proxies for the DCF's long-term, sustainable growth rates. Because the DCF analysis assumes that growth rates are constant in perpetuity, the five-year forecasted growth rates, when not sustainable in the long-run, are not appropriate for use in a constant growth rate DCF model. It is possible that investors may have different short-term and long-term expectations regarding a company's financial performance and earnings growth rate, and thus it may be reasonable to use more than one growth rate in a

DCF analysis. The two-growth DCF, described above, uses one growth rate for the first five years, and then a second, sustainable growth rate for year six and beyond.

The two-growth DCF model accounts for situations where the short-term projected growth rates may not be expected to continue in the long run. The short-term earnings growth rate may be unusually low or unusually high, relative to the company's historical averages, industry averages, or relative to the economy as a whole. Unusually low or high growth rates may result in unreasonably low or high estimates of the cost of equity. In order to determine if the growth rates from the three investor services are unusually low or high, the Department calculated the average growth rate for the DOC Proxy Groups, as well as the standard deviation of the growth estimates. Any growth rate that is lower than one standard deviation below or above the proxy group's average may not be sustainable. The Department used each proxy group's average growth rate plus and minus one standard deviation as the ceiling and floor, respectively, for sustainable growth rates.

The results of the Department's two-growth DCF analysis are summarized in Table 3.

Table 3
Summary of Two-Growth DCF Results

Model	Mean Low ROE	Mean ROE	Mean High ROE
EPG	8.12%	8.80%	9.76%
EPG	8.37%	9.28%	10.06%

ROE Attachments 4-6 and 8-10

The Department notes that these results, like the constant growth DCF results, include a flotation cost adjustment.

3. Flotation Costs

Flotation costs are the costs of issuing new shares of common stock. Due to issuance costs, the price paid by an investor for a new share is higher than the price received by the company issuing the new share. As a result, the company must earn a higher percentage return on its stock issuance proceeds than investors require on their investments in order to meet investor's required rate of return. For example, if a company issues $1 million worth of new common stock, and incurs flotation costs of four percent, the company will receive only $960,000 from the issuance. If the company's equity investors' require a 10 percent annual return on their initial investment of $1 million, the company must generate $100,000 per year on the proceeds from its stock issuance in order to compensate the new stockholders. In order to generate a return of \$100,000 per year on net proceeds of \$960,000, the company must earn an annual return of 10.42 percent (\$100,000 / \$960,000 = 0.1042). If the company earns only a 10.00 percent rate of return, it will generate only \$96,000 per year, and thus investors would not receive their required return.

Flotation costs are permanent, meaning that an adjustment is required for flotation costs incurred for all past issuances; otherwise investors will not receive their required return. Flotation costs have long been explicitly included in the company's cost of debt issued in the past, and the same principle applies to the company's common equity.[6]

The DCF model (as well as the CAPM) measures the required return on the value of shareholders' equity holdings (i.e. the 10 percent in the example above), not the required return on a company's net proceeds from stock issuances. Thus, if my DCF ROE estimate is applied directly without an adjustment for flotation costs, NSPM would not earn returns high enough to satisfy the expectations under which its investors purchased stock. A flotation cost adjustment corrects this problem.

The dividend yields of the companies in the DOC Proxy Groups must be adjusted by dividing them by 1-F, where F is the percentage of flotation costs. The Department used the same estimate of F as it used in the 2016 Rate Case, 2.85 percent.[7] Adjusting for flotation costs increased the DCF cost of equity estimates by 8-10 basis points.

4. The Capital Asset Pricing Model

As noted above, the Department used the CAPM as a check on the reasonableness of its DCF analyses.

The basic premise of CAPM is that any company-specific risk can be diversified away by investors. Therefore, the only risk that matters is the systematic risk of the stock, which is measured by beta. In its simplest form, CAPM assumes the following:

$$k = r_f + \text{beta} \times (r_m - r_f)$$

Where k is the required rate of return on the stock in question, r_f is the rate of return on a riskless asset, and r_m is the required rate of return on the market portfolio.

[6] The Department is aware that in some recent rate cases, the Commission has denied recovery of flotation costs. The Department, however, continues to conclude that recovery of flotation costs, when such costs are reasonably estimated, is reasonable.

[7] See Hearing Exhibit 803 at 25 in the 2016 Rate Case. Additionally, the Department notes that this estimate of F reflects both cost of the Company's public equity issuances as well as its low-cost non-public issuances of equity via dividend reinvestment programs, employee benefits, etc.

While the CAPM is theoretically sound, its use as a method to estimate a company's cost of equity raises some difficult issues. These concerns include difficulty determining 1) the appropriate beta, 2) the appropriate riskless asset, and 3) a reasonable estimate of the required return on the market portfolio**.** Because of these issues, the Department does not use the results of its CAPM analysis directly to determine NSPM's required return on equity. Rather, the CAPM analysis is used only to assess the reasonableness of the results of the Department's DCF analyses.

Additionally, the Commission has, in past Dockets, expressed a clear preference for DCF analyses. For example, in Docket No. E002/GR-13-868, a recent Xcel Energy electric rate case, the Commission, in its May 8, 2015 Order at 53, stated that the DCF is the method "on which this Commission has historically placed its heaviest reliance."[8]

a. The Risk-Free Rate

Theoretically, the yield on a 90-day Treasury bill is virtually riskless, devoid of default risk, and subject to a negligible amount of interest rate risk (which is the risk that the holder of an asset will experience losses as a result of interest rates increasing after the asset is purchased). However, equity investors generally have an investment horizon far in excess of 90 days. Thus, an equity investor wanting to invest in an asset yielding the risk free rate for a period comparable to the investor's stock holding period would face reinvestment risk, which is the risk that proceeds from the payment of principal and interest would have to be reinvested at a lower rate than the original investment, if the investor were to invest in 90-day Treasury bills.

While a 30-year Treasury bond, which is also generally considered to be devoid of default risk, may better match the equity investor's stock holding period, investing in a 30-year Treasury bond would subject the investor to significant interest rate risk, which, in a more general sense, is the risk associated with investment opportunities foregone because cash is tied up in investments made earlier. For example, if a person buys a 30-year Treasury bond carrying a six percent interest rate today, and a year later a new 30-year Treasury bond with a rate of seven percent is issued, then holding the original bond to maturity would cost this person the opportunity to earn seven percent interest, rather than six percent for the next 29 years. Thus, interest rate risk exists even when assets are held to maturity.

As a means to balance the risks associated with short-term and long-term treasuries, the Department used the average yield on 20-year Treasury bonds over the 30 trading days ending March 19, 2018, which is 3.01 percent.[9]

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[8] The Commission made the same statement in its June 3, 2016 Findings of Fact, Conclusions, and Order in Docket No. G008/GR-15-424.
[9] See ROE Attachment 16.

b. The Market Rate of Return

The Department used the S&P 500 as a proxy for the market portfolio, and performed a DCF analysis on the S&P 500 to determine the required rate of return. The dividend yield for the S&P 500 as of March 21, 2018 was 1.80 percent.[10] Thomson provides five-year projected earnings per share growth rates for the S&P 500 Index. As of March 21, 2018, this projected growth rate was 12.00 percent.[11] The Department applied the same adjustment to this dividend yield that it applied in its DCF analyses of the two proxy groups to reflect expected dividend growth during the next year, resulting in a dividend yield of 1.91 percent.

Using a DCF analysis, the required rate of return on the S&P 500 is 1.91 percent + 12.00 percent = 13.91 percent.

c. Beta

The Department calculated two estimates of beta, one using the average beta reported by Value Line of the companies in the EPG, and one using the companies in the CPG.

d. CAPM Results

My CAPM estimate of the cost of equity for the EPG, including a 10 basis point adjustment for flotation costs, is 11.01 percent. My CAPM estimate of the cost of equity for the CPG, including a flotation cost adjustment, is 10.90 percent.

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 my DCF results.

E. RECOMMENDED RETURN ON EQUITY AND WEIGHTED AVERAGE COST OF CAPITAL FOR NSPM

The Department used a weighted average of its mean two-growth DCF results for the DOC Proxy Groups. As noted above, the DCF model is a fair, market-oriented method that uses current, relevant information to allow NSPM to compete sufficiently and fairly in the capital markets and thus my DCF results should be used to determine the reasonable rate of return on common equity capital for NSPM. Also as noted above, the Commission has a long history of relying principally on the DCF method to determine a reasonable return on equity for public utilities. The DCF method allows one to calculate investors' likely expectations of the cost of equity capital for NSPM based on the rates of return of comparable companies. Because the purpose of this proceeding is to estimate the required rate of return for the electric operations of NSPM, the DCF result for the EPG should be assigned more weight than the DCF result for the

[10] See DOC Attachment 18.
[11] See DOC Attachment 17.

CPG. However, because the companies in the CPG are primarily engaged in the provision of retail electric services, the DCF result for my CPG also has significant analytical value.

Consistent with past practice, the Department assigned weights of 60 percent and 40 percent to the mean average two-growth DCF results for the EPG and CPG, respectively.

Table 4
Calculation of Recommended ROE

Model	Mean Average Two-Growth DCF ROE Estimate	Weights	Weighted ROE
EPG	8.80%	60.00%	5.28%
CPG	9.28%	40.00%	3.71%
Recommended ROE			8.99%

ROE Attachments 4 and 8

These weights produce a final ROE estimate for NSPM of 8.99 percent, including flotation costs. The Department recommends that the Commission approve an ROE of 8.99 percent for use in NSPM's TCR Rider, as well as any other riders filed before the Company concludes its next rate case.

III. RESPONSE TO NSPM'S ROE ANALYSIS

The Company used constant growth DCF analyses, Risk Premium analyses, and CAPM analyses to develop a range of estimates of NSPM's cost of equity. In determining a final recommended ROE from within that range, the Company considered a number of additional factors, including:

- flotation costs;
- current market conditions and their impact on ROE estimates produced with DCF analyses;
- ROEs authorized during 2016 and 2017 by non-Minnesota commissions in non-Minnesota jurisdictions; and
- the change yields on 10-year Treasury bonds since the Settlement in the 2016 Rate Case was negotiated.

The Company ultimately recommended that the Commission authorize an ROE of 10.00 percent for the Company.

The Department has several concerns with the Company's ROE analysis, particularly with Company's CAPM and Risk Premium analyses, as well as its assertion that current market conditions have rendered DCF results unreliable. The Department describes the Company's ROE analysis and discusses its concerns in greater detail below.

A. THE COMPANY'S PROXY GROUP

The Company's proxy group selection process, described on pages 14-17 of the Concentric Report, is similar to the Department's, although there are a few notable differences that result in different companies being included the Company's and the Department's proxy groups.

First, like the Department, the Company included a screen based on credit ratings. However, the Company's proxy group includes companies with credit ratings of BBB- and higher, while the Department eliminated companies with credit ratings of BBB-.[12] As a result, the Company's proxy group includes Hawaiian Electric Industries, Inc., while the DOC Proxy Groups do not.

Second, while both the Company and the Department included a screen based on operating income, the Company also screened out companies based on the percentage of their revenues derived from regulated operations. Additionally, the Company's operating income screen is structured differently than the Department's. To be included in the Company's proxy group, a company's operating income from regulated activities (electric or gas) had to be at least 60 percent of its total operating income, and the percentage of its operating income from regulated activities derived from electric operations (i.e. not gas) had to be at least 80 percent. The Company's revenue screen was structured in the same way.

While the Department does not view the Company's screening process to be egregiously flawed, the Department does conclude that it is overly restrictive. For example, the Company excludes NorthWestern Corporation despite the fact that 100 percent of its operations are regulated, and 77 percent and 84 percent of its revenue and operating income, respectively, from its electric operations. The Company also excluded CMS corporation despite the fact the nearly all of its operations are regulated, and its electric operations account for approximately 70 percent of its revenues and operating income. DTE Energy Company and Otter Tail Corporation are also excluded despite earning just under 80 percent of their total operating income from regulated electric operations. The Department considers all four of those companies to be reasonable proxies for NSPM.[13]

Finally, after the Concentric Report was completed, Southern Company announced the sale of two gas distribution utilities. The Department excluded Southern Company for that reason, while the Company included it in its proxy group. The Company also excluded NextEra Energy, Inc. because it was involved in a merger with Oncor Electric Delivery Co. However, that merger was terminated in July, 2017, so the Department included it in its EPG.

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[12] The Department also eliminated companies with S&P credit ratings above A+, while the Company did not. This difference in screening criteria, however, did not result in any differences in the final proxy group members.

[13] Additionally, the Department excluded PPL Corporation because it derives less than 60 percent of its operating income from U.S. regulated electric operations. The Department was unable to reproduce the Company's income and revenue data for PPL, and thus it is not clear exactly why PPL passed the Company's screens.

B. THE COMPANY'S DCF ANALYSES

As noted above, the two inputs to a constant growth DCF analysis are an expected dividend yield and a growth rate. In calculating the dividend yields in its constant growth DCF analysis, the Company applied a half year worth of growth to each proxy company's current dividend, as did the Department. However, the Company calculated dividend yields using three different estimates of each company's stock price, one using a 30-day average stock price, one using a 90-day average stock price, and one using a 180-day average stock price. For the second input, the growth rate, the Company used same estimated earnings growth rates as the Department (from Zacks, Thomson, and Value Line).

The Department agrees with Company's choice of growth rates, as well as its use of a 30-day averaging period to calculate stock prices. The Department does not agree that it is reasonable to use 90-day and 180-day averaging periods to calculate stock prices. Under the basic financial principle that financial markets are efficient, current stock prices fully reflect all publicly available information. By using 90-day and 180-day averaging periods, the Company relies on older stock prices that may reflect out-of-date, irrelevant information. While the use of "stale" stock prices has the potential to unreasonably bias the results of a DCF analysis, the Department notes that the difference between the Company's constant growth DCF results calculated using the 30-day averaging period and the results derived from the 180-day averaging period, as shown on page 19 of the Concentric Report, is only 14 basis points.

C. THE COMPANY'S RISK PREMIUM ANALYSES

1. Description of the Company's Risk Premium Analyses

As described in Appendix 2 of the Concentric Report, the Risk Premium approach treats the cost of equity as a sum of a reference bond yield and an equity risk premium. Using data regarding ROE's allowed in electric rate proceedings from 1993 through September, 2017, the Company performed a regression analysis to determine the relationship between the equity risk premium for electric utilities and 30-year Treasury yields. The Company then used the results of this regression and three different estimates of 30-year Treasury yields to produce estimates of NSPM's cost of equity. First, the Company used the current 30-day average yield on 30-year Treasuries, 2.77 percent, which produced an ROE estimate of 9.74 percent. Second, the Company used a near term forecast of yields over the period 4Q 2017 – 1Q 2019, 3.30 percent, to produce an ROE estimate of 9.97 percent. Third, the Company used a long-term forecast of 30-year Treasury yields over the period 2019-2023, 4.30 percent, to produce an ROE estimate of 10.41 percent.

The Company then performed a second regression analysis to estimate the relationship between the equity risk premium for electric utilities and A-rated utility bond yields. Using the results of this regression and three estimates of current and expected utility bond yields, the Company estimated NSPM's cost of equity to be between 9.62 and 10.36 percent. Again, the

Company used a current 30-day average yield, a near-term projected yield, and a long-term projected yield to derive its ROE estimates. The long-term projected yield on A-rate utility bonds is equal to the long-term forecast of Treasury yields (4.30 percent) that the Company used in its first Risk Premium analysis, plus the average spread between 30-year Treasury yields and A-rated utility bonds over the period January 1, 2015 through September 29, 2017.

The Company stated that it believes that the estimates derived using the long-term forecasts of interest rates are the most applicable because "they are forward-looking, and investors typically have a multi-year forward view of their estimates of the cost of equity."[14]

2. Department Response

The Department has two significant concerns with the Company's Risk Premium analyses. First and foremost, the Risk Premium approach is a backward-looking approach that assumes that the relationship between the equity risk premium and the reference bond yield is static over time. In other words, the Risk Premium approach assumes that whenever the yield on 30-year U.S. Treasuries is 2.77 percent, the risk premium for equity utilities will always be 6.96 percent, regardless of any other prevailing factors impacting the economy broadly, or the electric industry specifically.

It is not reasonable to assume that investors will not adjust their behavior to adapt to changes in the economic environment; thus a backward-looking view of the relationships cannot be used to estimate the expected the risk premium on a going-forward basis. The Company has not shown that it is reasonable to assume that the cost of equity to electric utilities is solely a function of 30-year Treasury yields or utility bond yields.

Second, the Company's use of projected Treasury yields and utility bond yields is unreasonable. Long-term interest rates are determined by market forces, and thus reflect current investor expectations of future economic and financial conditions. Because current, actual bond yields reflect investor expectations about the future, changes in actual bond yields occur as a result of unexpected changes in future expectations, which are of course difficult to predict. For this reason, actual bond yields are superior to forecasted yields, which are subject to uncertainty and estimation error.

The Company's use of a long-term forecasted average 30-year Treasury yield over the period 2019-2023 of 4.30 percent is particularly inappropriate. Such long-term forecasts are subject to too much uncertainty to be relied upon and the ROE estimate produced by it should be given little to no weight. Blue Chip Financial Forecasts, the publication from which the Company sourced this forecasted yield, includes the following caution about this forecast:

[14] Concentric Report at 23.

> Apply these projections cautiously. Few economic, demographic and political forces can be evaluated accurately over such long time spans.[15]

The Department also disagrees with the Company's preference for long-term forecasted interest rates, which the Company stated is based on the idea that such forecasts are forward-looking. The Company's position inappropriately conflates "forward-looking" with "forecasted." As stated above, current interest rates reflect expectations of future economic and financial conditions, and thus are forward-looking. Interest rates are for bonds what the cost of equity is for stocks; they are the discount rate that sets the present value of future cash flows equal to the current price. For stocks, that discount rate is not directly observable. For bonds, that interest rate is directly observable. Given that current interest rates are directly observable and forward-looking, there is simply no good reason to try to rely on unreliable long-term forecasts of interest rates.

D. THE COMPANY'S CAPM ANALYSIS

1. Description of the Company's CAPM Analyses

As discussed above, a CAPM analysis requires an estimate of the required return on the market portfolio, an estimate of beta, and an estimate of the risk-free rate. In its CAPM analyses, the Company used one estimate of the required return on the market portfolio, two estimates of beta, and three estimates of the risk-free rate, for a total of six CAPM ROE estimates, ranging from 8.86 percent to 10.78 percent.[16]

Like the Department, the Company used the S&P 500 index as a proxy for the market portfolio. The Company performed constant growth DCF analyses for each of companies included in the index, and then calculated the average ROE, weighted by market capitalization, to derive its estimate of the required return on the market portfolio.

For its estimates of beta, the Company used betas from Bloomberg and Value Line.

For its estimates of the risk-free rate, the Company used the same three 30-year Treasury yield estimates it used in its Risk Premium Analyses: a current 30-day average yield, a near-term projected yield, and a long-term projected yield.

The Company also reiterated its preference for using a long-term forecasted interest rate to derive its CAPM estimates, as it did with its Risk Premium estimates.

[15] See Exhibit CPE-50, workpaper 14 at 14, in Docket No. G008/GR-17-285, included here as ROE Attachment 20.
[16] See Concentric Report, Appendix 3, Schedule 4.3.

2. Department Response

The Department concludes that the Company's estimate of the required return on the market portfolio is reasonable, as are the Company's estimates of beta.

As described above, the yield on 30-year Treasuries includes a larger interest rate risk premium than the yield on 20-year Treasuries, which is why the Department used the latter as the risk-free rate in its CAPM analysis. However, the Department notes that the difference between using current 30-year Treasury yields versus 20-year Treasury yields is small, and would lower the Company's CAPM estimates by only 8-11 basis points.[17]

The Company's use of projected yields, however, is unreasonable, for the same reasons its use of projected yields in its Risk Premium analyses was unreasonable, as discussed above. The Company's CAPM estimates derived using the long-term forecasted 30-year Treasury yield, in particular, should be given no weight by the Commission in determining NSPM's authorized ROE.

Additionally, the Department notes that the Company's CAPM results highlight the difficulties referenced above associated with selecting appropriate inputs for use in a CAPM analysis. The Company's estimate derived using Bloomberg betas, 8.86 percent, is 146 basis points lower than its estimate derived using Value Line betas, 10.32 percent. This difference, produced even though two of the three inputs to the CAPM are identical, demonstrates how sensitive the CAPM can be to different inputs, even when the inputs are sourced from respected, widely-used sources of financial data, as both Bloomberg and Value Line are.

E. CURRENT MARKET CONDITIONS AND IMPACTS ON DCF RESULTS

1. The Company's Analysis of Current Market Conditions and Their Impact on DCF Results

Beginning on page 8 of the Concentric Report, the Company asserted that Federal Reserve policy since the Great Recession of 2008-09 has driven interest rates on Treasury bonds to historically low levels, and that this factor has caused investors to search for higher yield in common stocks, and particularly in dividend-paying stocks such as utilities. In doing so, according to the Company, investors have driven the prices of these stocks higher, meaning that dividend yields have been driven lower, which in turn has driven DCF results lower.[18]

The Company then asserted that current utility stock valuations are "unsustainable," because investors expect long-term rates to rise as the Federal Reserve normalizes monetary policy.[19] Although unstated, the Company's implication is that rising rates will cause investors to move away from utility stocks and drive their prices down, resulting in higher dividend yields and

[17] See ROE Attachment 21.
[18] Concentric Report, at 9.
[19] Concentric Report, at 13.

higher DCF results. The Company stated that DCF results that are based on these "unsustainable" stock prices are "likely understating the forward-looking cost of equity for the proxy group companies under these circumstances."[20] The Company also stated that "it is not appropriate to rely solely on the results of the DCF model because that model is based on historical stock prices, which are used to calculate the dividend yield"[21] and that "[i]t would not be appropriate to base the ROE determination on models that only take into consideration historical data which is from a period when the interest rate environment was much different than investors are expecting in the near future."[22]

Additionally, the Company referred to two Opinions from the Federal Energy Regulatory Commission (FERC) in which the FERC concluded that anomalous market conditions were impacting DCF results such that the FERC had "less confidence" that the mid-point of the range of DCF results accurately reflected utilities' cost of equity. The Company asserted that the FERC determined that when yields on 10-year Treasuries are below 3.0 percent, market conditions are anomalous, and further asserted that because 10-year Treasury yields are currently below 3.0 percent, market conditions are still anomalous.

2. Department Response

The Department disagrees with the Company's analysis on several fronts.

First, the Company's assertions that DCF analyses are not forward-looking, and that current stock prices are "historical data" are false. Asset prices, including stock prices, represent the collective assessment of investors of the present value of future cash flows associated with those assets, and thus are forward looking, not "historical." As shown in Equation [1] above, the very idea behind DCF analysis is to find the discount rate that sets the present value of all expected future dividend payments equal to the current stock price. Thus DCF analysis is, by definition, forward looking.

Second, the Company's unstated assertion that utility stock valuations are going to fall over the next few years is contrary to financial theory. Reasonable investors would not hold an investment if they believed that it is likely to perform poorly. Thus, if investors expected the price of a stock to fall, they would sell the stock, bidding the price of the stock down until it reaches a point at which the expected return meets investors' required return. If investors expect interest rates to rise in the future, and also expect that rise to negatively impact the price of their stock holdings, they will bid the price of their stock holdings down until its expected return matches its required return.

In this way, the expectation and uncertainty regarding the future actions of the Federal Reserve and the impacts on interest rates are already fully reflected in stock prices. And because the financial models used to estimate the cost of equity rely on current stock prices, the results of

[20] Concentric Report, at 10.
[21] Concentric Report, at 13-14.
[22] Concentric Report, at 19.

those models also reflect current investor expectations. Therefore, any additional adjustments, either direct or indirect, intended to reflect investor expectations would not only be unnecessary, they would be inappropriately duplicative.

Third, the Department disagrees that the two FERC Opinions are relevant to the Commission's assessment of NSPM's current ROE. The more recent of the two Opinions was issued more than a year before the Company filed its TCR Petition, and is based on an assessment of market conditions during the first six months of 2015.[23] In the nearly three years since the study period, yields on 10-year Treasuries have remained below 3.0 percent. In fact, since July 11, 2011, 10-year Treasury yields have been below 3.0 percent for all but seven trading days, and have not risen above 3.04 percent. Given that these conditions have persisted for nearly seven years, it is no longer reasonable to conclude that they are anomalous.[24]

F. THE COMPANY'S ASSESSMENT OF ROES APPROVED IN OTHER JURISDICTIONS

1. The Company's Analysis

The Company stated that FERC Opinion 551, which authorized an ROE of 10.32 percent for MISO transmission owners, provides a relevant benchmark because it is specific to transmission investment by regulated utilities in this region of the country.

The Company also provided an analysis of ROEs authorized in Minnesota relative to other state jurisdictions. The Company stated that ROEs in Minnesota have steadily declined since 2009, and that in 2017, ROEs authorized by the Commission were near the bottom of the range of ROEs authorized in other states. The Company also calculated that the average authorized ROE for integrated utility companies in 2016 and 2017 was 9.74 percent. The Company used this average as a benchmark in developing its final recommendation.

2. Department Response

FERC's authorized ROE for MISO transmission owners is irrelevant to the decisions in this proceeding for several reasons. First, it is based on an analysis conducted in 2015, meaning that it is three years out of date, and is thus historical, not forward-looking. Second, FERC arrived that authorized ROE using the same method that the D.C. Circuit Court of Appeals rejected in a different FERC Docket, based on the D.C. Court's opinion that FERC did not establish a rational connection between the record evidence and its final recommendation.

Third, as the Company makes clear on pages 25 and 26 of the Concentric Report, FERC's authorized ROE is specific to transmission companies, not vertically integrated electric utilities. This Commission has never established separate ROEs for transmission, distribution, and generation. Rather, this Commission determines a single ROE that is appropriate for a vertically

[23] See FERC Opinion 551, Docket EL14-12-002, para. 19.
[24] Merriam-Webster defines "anomalous" as "inconsistent with or deviating from what is usual, normal, or expected."

integrated electric utility, and then applies that ROE uniformly across all of the utility's investments. This is the most reasonable approach, and it would be unreasonable to change this approach now.

The Department also disagrees with the Company's assessment of ROEs authorized in state jurisdictions. The Company's statement that Minnesota ROEs have been declining since 2009, while true, is misleading. As shown clearly in Figure 10 of the Concentric Report, ROEs across all state jurisdictions have been declining since 2009, and in all years except 2017, Minnesota ROEs have been close to average across all jurisdictions. Contrary to the Company's statements, the Company's own analysis does not show Minnesota to be an outlier in any way.

Finally, the Company's use of the average authorized ROE in 2016 and 2017 as a benchmark for NSPM's current ROE is unreasonable. ROEs authorized in 2016 are precisely the type of historical information that the Commission should avoid, and the Company purports to wish to avoid.

G. THE COMPANY'S SUMMARY AND CONCLUSIONS

1. The Company's Summary of its Results and Recommendation

On pages 28-29 of the Concentric Report, the Company summarizes its results and conclusions. The Company presents its 90-day constant growth DCF result and its four Risk Premium and CAPM results derived using its long-term forecasted interest rates. The Company calculated the average of these five ROE estimates, 9.85 percent, and taking into consideration other factors such as ROEs approved in other jurisdictions, ultimately recommended that the Commission approve an authorized ROE of 10.0 percent.

2. Department Response

The Company's summary of its results ignores its Risk Premium and CAPM derived using current interest rates, and instead reflects only its unreasonable ROE estimates derived using long-term forecasted interest rates. Simply replacing those unreasonable estimates with the estimates derived using current interest rates would lower the Company's average result by 50 basis points, from 9.85 percent to 9.35 percent.

Table 5
Impact of Relying on Long-term Interest Rate Forecast

	Company Estimate Derived with:		
ROE Estimation Method	Long-Term Interest Rate Forecast	Current Interest Rate	Difference
90-Day Constant Growth DCF	8.19%	8.19%	n/a
Risk Premium			
30 Yr. US Treasury	10.41%	9.74%	-0.67%
Moody's A-rated Utility Index	10.36%	9.62%	-0.74%
CAPM			
Value Line Beta	10.78%	10.32%	-0.46%
Bloomberg Beta	9.52%	8.86%	-0.66%
Average	9.85%	9.35%	-0.51%

The Company's heavy weighting of its Risk Premium and CAPM results in developing its average results (40 percent each, versus 20 percent for its DCF results) is also unreasonable. Because the Company's Risk Premium analysis uses historical data to estimate the relationship between interest rates and the cost of equity, it is backward-looking and unreasonable. The Company's use of a forecasted interest rate does not make its Risk Premium analysis forward-looking. As discussed above, the CAPM is subject to significant estimation error, as evidenced by the large difference between the Company's results derived using Bloomberg betas and its results derived with Value Line Betas.

Further, the additional factors (e.g. ROEs authorized by FERC and other state commissions) considered by the Company that led it to its recommendation of 10.0 percent, rather than 9.85 percent, are all irrelevant as discussed above.

IV. CONCLUSION

The Department recommends that the Commission approve and ROE of 8.99 percent for NSPM, based on its mean two-growth DCF analysis, and further recommends that this ROE be used until NSPM concludes its next elecstric rate case.

Electric Proxy Group Screen

Company	Ticker	SIC	Incorporated in US	Credit Rating Screen	Preliminary Screen	Covered By Value Line	Consistent Dividend	Zacks or Thomson	M&A Activity	60% Operating Income from Retail Elec.	Vertically Integrated or at Least 25% of Sales from Owned	EPG Member
AMERICAN ELECTRIC POWER CO	AEP	4911	y	y	y	y	y	y	n	y	y	y
AVANGRID INC	AGR	4911	y	y	y	n						
AZURE POWER GLOBAL LTD	AZRE	4911	n	n	n							
BLACK HILLS CORP	BKH	4911	y	y	y	y	y	y	n	n		
BROOKFIELD INFRS PTRS LP	BIP	4911	n	y	n							
CENTRAIS ELETRICAS -ADR	EBR	4911	n	n	n							
CIA ENERGETICA MINA GERA-ADR	CIG	4911	n	n	n							
CIA PARANAENSE ENERGIA -ADR	ELP	4911	n	n	n							
CPFL ENERGY INC -ADR	CPL	4911	n	n	n							
DOMINION ENERGY INC	D	4911	y	y	y	y	y	y	y			
EDISON INTERNATIONAL	EIX	4911	y	y	y	y	y	y	n	y	n	
EL PASO ELECTRIC CO	EE	4911	y	y	y	y	y	y	n	y	y	y
EMPIRE DISTRICT ELECTRIC CO	EDE	4911	y	n	n	n						
EMPRESA DISTRIB Y COMERC-ADR	EDN	4911	n	n	n							
ENEL AMERICAS SA -ADR	ENIA	4911	n	y	n							
ENEL CHILE SA -ADR	ENIC	4911	n	n	n							
ENEL GENERACION CHILE -ADR	EOCC	4911	n	y	n							
ENTERGY CORP	ETR	4911	y	y	y	y	y	y	n	n		
EXELON CORP	EXC	4911	y	y	y	y	y	y	n	n		
FIRSTENERGY CORP	FE	4911	y	n	n	y						
FORTIS INC	FTS	4911	n	y	n							
GREAT PLAINS ENERGY INC	GXP	4911	y	y	y	y	y	y	y			
HAWAIIAN ELECTRIC INDS	HE	4911	y	n	n	y						
HUANENG POWER INTL INC -ADR	HNP	4911	n	n	n							
IDACORP INC	IDA	4911	y	y	y	y	y	y	n	y	y	y
KOREA ELECTRIC POWER CO -ADR	KEP	4911	n	n	n							
NATIONAL GRID PLC -ADR	NGG	4911	n	y	n							
NEXTERA ENERGY INC	NEE	4911	y	y	y	y	y	y	n	y	y	y
NEXTERA ENERGY PARTNERS LP	NEP	4911	y	n	n	n						
NRG ENERGY INC	NRG	4911	y	n	n	y						
NRG YIELD INC	NYLD	4911	y	n	n	n						
ORMAT TECHNOLOGIES INC	ORA	4911	y	n	n	y						
OTTER TAIL CORP	OTTR	4911	y	y	y	y	y	y	n	y	y	y
PAMPA ENERGIA SA -ADR	PAM	4911	n	n	n							
PINNACLE WEST CAPITAL CORP	PNW	4911	y	y	y	y	y	y	n	y	y	y
PNM RESOURCES INC	PNM	4911	y	y	y	y	y	y	n	y	y	y
PORTLAND GENERAL ELECTRIC CO	POR	4911	y	y	y	y	y	y	n	y	y	y
PPL CORP	PPL	4911	y	y	y	y	y	y	n	n		
SOUTHERN CO	SO	4911	y	y	y	y	y	y	y			
TERRAFORM POWER INC	TERP	4911	y	n	n	n						
TRANSALTA CORP	TAC	4911	n	n	n							
VISTRA ENERGY CORP	VST	4911	y	n	n	y						

Combination Proxy Group Screen

Company	Ticker	SIC	Incorporated in US	Credit Rating Screen	Preliminary Screen	Covered By Value Line	Consistent Dividend	Zacks or Thomson	M&A Activity	60% Operating Income from Retail Elec.	Vertically Integrated or at Least 25% of Sales from Owned	CPG Member
ALLETE INC	ALE	1	y	y	y	y	y	y	n	y	y	y
ALLIANT ENERGY CORP	LNT	4931	y	y	y	y	y	y	n	y	y	y
AMEREN CORP	AEE	4931	y	y	y	y	y	y	n	n	y	
AVISTA CORP	AVA	4931	y	y	y	y	y	y	y			
CENTERPOINT ENERGY INC	CNP	4931	y	y	y	y	y	y	n	y	n	
CENTRAL PUERTO SA -ADR	CEPU	4931	n	n	n	n						
CMS ENERGY CORP	CMS	4931	y	y	y	y	y	y	n	y	y	y
CONSOLIDATED EDISON INC	ED	4931	y	y	y	y	y	y	n	y	n	
DTE ENERGY CO	DTE	4931	y	y	y	y	y	y	n	y	y	y
DUKE ENERGY CORP	DUK	4931	y	y	y	y	y	y	n	y	y	y
EVERSOURCE ENERGY	ES	4931	y	y	y	y	y	y	n	y	n	
GENIE ENERGY LTD	GNE	4931	y	n	n	n						
MGE ENERGY INC	MGEE	4931	y	n	n	y						
NORTHWESTERN CORP	NWE	4931	y	y	y	y	y	y	n	y	y	y
OGE ENERGY CORP	OGE	4931	y	y	y	y	y	y	n	y	y	y
PG&E CORP	PCG	4931	y	y	y	y	n					
PUBLIC SERVICE ENTRP GRP INC	PEG	4931	y	y	y	y	y	y	n	n	y	
SCANA CORP	SCG	4931	y	y	y	y	y	y	y			
SEMPRA ENERGY	SRE	4931	y	y	y	y	y	y	y			
SPARK ENERGY INC	SPKE	4931	y	n	n	n						
UNITIL CORP	UTL	4931	y	y	y	n						
WEC ENERGY GROUP INC	WEC	4931	y	y	y	y	y	y	n	**n**	**y**	
WESTAR ENERGY INC	WR	4931	y	y	y	y	y	y	y			
XCEL ENERGY INC	XEL	4931	y	y	y	y	y	y	n		y	

Constant Growth DCF Analysis - Electric Proxy Group

Company	Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate	Low Expected Dividend Yield	Mean Expected Dividend Yield	High Expected Dividend Yield	Low ROE	Mean ROE	High ROE
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
AMERICAN ELECTRIC POWER CO	AEP	65.91	2.48	3.76%	4.50%	5.18%	5.63%	3.85%	3.86%	3.87%	8.35%	9.04%	9.50%
EL PASO ELECTRIC CO	EE	49.53	1.34	2.71%	5.00%	5.10%	5.20%	2.77%	2.77%	2.78%	7.77%	7.87%	7.98%
IDACORP INC	IDA	83.18	2.36	2.84%	3.10%	3.57%	4.10%	2.88%	2.89%	2.90%	5.98%	6.45%	7.00%
NEXTERA ENERGY INC	NEE	153.61	4.44	2.89%	7.90%	8.42%	8.85%	3.00%	3.01%	3.02%	10.90%	11.43%	11.87%
OTTER TAIL CORP	OTTR	41.33	1.34	3.24%	7.00%	8.00%	9.00%	3.36%	3.37%	3.39%	10.36%	11.37%	12.39%
PINNACLE WEST CAPITAL CORP	PNW	76.98	2.78	3.61%	3.00%	4.04%	5.50%	3.67%	3.68%	3.71%	6.67%	7.73%	9.21%
PNM RESOURCES INC	PNM	35.64	1.06	2.97%	5.80%	6.37%	7.50%	3.06%	3.07%	3.09%	8.86%	9.44%	10.59%
PORTLAND GENERAL ELECTRIC CO	POR	40.02	1.36	3.40%	2.90%	4.13%	6.00%	3.45%	3.47%	3.50%	6.35%	7.60%	9.50%
Mean				3.18%	4.90%	5.60%	6.47%	3.25%	3.27%	3.28%	8.15%	8.87%	9.75%
Required ROE including flotation cost adjustment											8.25%	8.96%	9.85%
Flotation Costs											2.85%		

Sources and Notes:
[1] ROE Attachment 12
[2] ROE Attachment 11
[3] = [2] / [1]
[4] ROE Attachment 11
[5] ROE Attachment 11
[6] ROE Attachment 11
[7] = [3] x (1 + 0.5 x [4])
[8] = [3] x (1 + 0.5 x [5])
[9] = [3] x (1 + 0.5 x [6])
[10] = [4] + [7]
[11] = [5] + [8]
[12] = [6] + [9]

Two Growth Rate DCF Analysis - Electric Proxy Group
Mean Growth Rates

Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Mean Projected Growth Rate	Mean Expected Dividend Yield	Second Growth Rate		Mean Expected ROE
	[1]	[2]	[3]	[4]	[5]	[6]		[7]
AEP	65.91	2.48	3.76%	5.18%	3.86%	5.18%		9.04%
EE	49.53	1.34	2.71%	5.10%	2.77%	5.10%		7.87%
IDA	83.18	2.36	2.84%	3.57%	2.89%	3.89%		6.74%
NEE	153.61	4.44	2.89%	8.42%	3.01%	7.31%		10.47%
OTTR	41.33	1.34	3.24%	8.00%	3.37%	7.31%		10.78%
PNW	76.98	2.78	3.61%	4.04%	3.68%	4.04%		7.73%
PNM	35.64	1.06	2.97%	6.37%	3.07%	6.37%		9.44%
POR	40.02	1.36	3.40%	4.13%	3.47%	4.13%		7.60%
Mean			3.18%	5.60%	3.27%	5.42%		8.71%
With Flotation Costs								8.80%
		Average		5.60%				
		Std. Dev.		1.71%			Flotation Costs (F)	2.85%
		Avg. less St. Dev.		3.89%				
		Avg. plus St. Dev		7.31%				

Ticker	Year 1 Div.	(1+k)^1	PV of Year 1 Div.	Year 2 Div.	(1+k)^2	PV of Year 2 Div.	Year 3 Div.	(1+k)^3	PV of Year 3 Div.	Year 4 Div.	(1+k)^4	PV of Year 4 Div.	Year 5 Div.	(1+k)^5	PV of Year 5 Div.	Year 6 Div.	Year 5 Stock Price	PV of Year 5 Stock Price	Current Stock Price	CHECK
	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
AEP	2.54	1.09	2.33	2.68	1.19	2.25	2.81	1.30	2.17	2.96	1.41	2.09	3.11	1.54	2.02	3.27	84.84	55.05	65.91	0.00
EE	1.37	1.08	1.27	1.44	1.16	1.24	1.52	1.26	1.21	1.60	1.35	1.18	1.68	1.46	1.15	1.76	63.52	43.48	49.53	0.00
IDA	2.40	1.07	2.25	2.49	1.14	2.18	2.58	1.22	2.12	2.67	1.30	2.06	2.76	1.39	1.99	2.86	100.54	72.58	83.18	0.00
NEE	4.63	1.10	4.19	5.02	1.22	4.11	5.44	1.35	4.03	5.90	1.49	3.96	6.39	1.65	3.89	6.93	219.52	133.44	153.61	(0.00)
OTTR	1.39	1.11	1.26	1.51	1.23	1.23	1.63	1.36	1.20	1.76	1.51	1.17	1.90	1.67	1.14	2.05	58.98	35.35	41.33	0.00
PNW	2.84	1.08	2.63	2.95	1.16	2.54	3.07	1.25	2.46	3.19	1.35	2.37	3.32	1.45	2.29	3.46	93.86	64.69	76.98	0.00
PNM	1.09	1.09	1.00	1.16	1.20	0.97	1.24	1.31	0.94	1.32	1.43	0.92	1.40	1.57	0.89	1.49	48.53	30.92	35.64	0.00
POR	1.39	1.08	1.29	1.45	1.16	1.25	1.51	1.25	1.21	1.57	1.34	1.17	1.63	1.44	1.13	1.70	49.00	33.97	40.02	0.00

Sources and Notes:

[1] ROE Attachment 12
[2] ROE Attachment 12
[3] = [2] / [1]
[4] ROE Attachment 11
[5] = [3] x (1 + 0.5 x [4])
[6] if [4] is less than Group Avg. less St. Dev. (3.89%), then equal to 3.89%',
if [4] is greater than Group Avg. plu St. Dev. (7.31%), then equal to 7.31%
else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek functior
Adjustment for Flotation costs: ROE = [7] - [5] + [5]/(1-F)
[8] = [1] x [5]
[9] = (1 + [7])^1
[10] = [8] / [9]
[11] = [8] x (1 + [4])
[12] = (1 + [7])^2
[13] = [11] / [12]
(continued)

Sources and Notes, Continued:

[14] = [11] x (1 + [4])
[15] = (1 + [7])^3
[16] = [14] / [15]
[17] = [14] x (1 + [4])
[18] = (1 + [7])^4
[19] = [17] / [18]
[20] = [17] x (1 + [4])
[21] = (1 + [7])^5
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

Two Growth Rate DCF Analysis - Electric Proxy Group
Low Growth Rates

Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Low Projected Growth Rate	Low Expected Dividend Yield	Second Growth Rate		Low Expected ROE
	[1]	[2]	[3]	[4]	[5]	[6]		[7]
AEP	65.91	2.48	3.76%	4.50%	3.85%	4.50%		8.35%
EE	49.53	1.34	2.71%	5.00%	2.77%	5.00%		7.77%
IDA	83.18	2.36	2.84%	3.10%	2.88%	3.12%		6.00%
NEE	153.61	4.44	2.89%	7.90%	3.00%	6.68%		9.84%
OTTR	41.33	1.34	3.24%	7.00%	3.36%	6.68%		10.08%
PNW	76.98	2.78	3.61%	3.00%	3.67%	3.12%		6.77%
PNM	35.64	1.06	2.97%	5.80%	3.06%	5.80%		8.86%
POR	40.02	1.36	3.40%	2.90%	3.45%	3.12%		6.54%
Mean			3.18%	4.90%	3.25%	4.75%		8.03%
With Flotation Costs								8.12%
		Average		4.90%				
		Std. Dev.		1.78%			Flotation Costs (F)	2.85%
		Avg. less St. Dev.		3.12%				
		Avg. plus St. Dev		6.68%				

Ticker	Year 1 Div.	(1+k)^1	PV of Year 1 Div.	Year 2 Div.	(1+k)^2	PV of Year 2 Div.	Year 3 Div.	(1+k)^3	PV of Year 3 Div.	Year 4 Div.	(1+k)^4	PV of Year 4 Div.	Year 5 Div.	(1+k)^5	PV of Year 5 Div.	Year 6 Div.	Year 5 Stock Price	PV of Year 5 Stock Price	Current Stock Price	CHECK
	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
AEP	2.54	1.08	2.34	2.65	1.17	2.26	2.77	1.27	2.18	2.89	1.38	2.10	3.02	1.49	2.03	3.16	82.14	55.01	65.91	0.00
EE	1.37	1.08	1.27	1.44	1.16	1.24	1.51	1.25	1.21	1.59	1.35	1.18	1.67	1.45	1.15	1.75	63.21	43.48	49.53	0.00
IDA	2.40	1.06	2.26	2.47	1.12	2.20	2.55	1.19	2.14	2.63	1.26	2.08	2.71	1.34	2.02	2.79	97.00	72.48	83.18	0.00
NEE	4.62	1.10	4.20	4.98	1.21	4.13	5.37	1.33	4.05	5.80	1.46	3.98	6.26	1.60	3.91	6.75	213.20	133.33	153.61	0.00
OTTR	1.39	1.10	1.26	1.48	1.21	1.22	1.59	1.33	1.19	1.70	1.47	1.16	1.82	1.62	1.12	1.95	57.17	35.37	41.33	0.00
PNW	2.82	1.07	2.64	2.91	1.14	2.55	2.99	1.22	2.46	3.08	1.30	2.37	3.18	1.39	2.29	3.27	89.73	64.67	76.98	0.00
PNM	1.09	1.09	1.00	1.15	1.19	0.97	1.22	1.29	0.95	1.29	1.40	0.92	1.37	1.53	0.89	1.45	47.25	30.91	35.64	0.00
POR	1.38	1.07	1.30	1.42	1.14	1.25	1.46	1.21	1.21	1.50	1.29	1.17	1.55	1.37	1.13	1.59	46.63	33.97	40.02	(0.00)

Sources and Notes:
[1] ROE Attachment 12
[2] ROE Attachment 12
[3] = [2] / [1]
[4] ROE Attachment 11
[5] = [3] x (1 + 0.5 x [4])
[6] if [4] is less than Group Avg. less St. Dev. (3.12%), then equal to 3.12%',
if [4] is greater than Group Avg. plu St. Dev. (6.68%), then equal to 6.68%
else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek functior
Adjustment for Flotation costs: ROE = [7] - [5] + [5]/(1-F)
[8] = [1] x [5]
[9] = (1 + [7])^1
[10] = [8] / [9]
[11] = [8] x (1 + [4])
[12] = (1 + [7])^2
[13] = [11] / [12]
(continued)

Sources and Notes, Continued:
[14] = [11] x (1 + [4])
[15] = (1 + [7])^3
[16] = [14] / [15]
[17] = [14] x (1 + [4])
[18] = (1 + [7])^4
[19] = [17] / [18]
[20] = [17] x (1 + [4])
[21] = (1 + [7])^5
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

Two Growth Rate DCF Analysis - Electric Proxy Group
High Growth Rates

Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	High Projected Growth Rate	High Expected Dividend Yield	Second Growth Rate		High Expected ROE
	[1]	[2]	[3]	[4]	[5]	[6]		[7]
AEP	65.91	2.48	3.76%	5.63%	3.87%	5.63%		9.50%
EE	49.53	1.34	2.71%	5.20%	2.78%	5.20%		7.98%
IDA	83.18	2.36	2.84%	4.10%	2.90%	4.81%		7.61%
NEE	153.61	4.44	2.89%	8.85%	3.02%	8.14%		11.25%
OTTR	41.33	1.34	3.24%	9.00%	3.39%	8.14%		11.65%
PNW	76.98	2.78	3.61%	5.50%	3.71%	5.50%		9.21%
PNM	35.64	1.06	2.97%	7.50%	3.09%	7.50%		10.59%
POR	40.02	1.36	3.40%	6.00%	3.50%	6.00%		9.50%
Mean			3.18%	6.47%	3.28%	6.36%		9.66%
With Flotation Costs								9.76%
		Average		6.47%				
		Std. Dev.		1.67%			Flotation Costs (F)	2.85%
		Avg. less St. Dev.		4.81%				
		Avg. plus St. Dev		8.14%				

Ticker	Year 1 Div.	(1+k)^1	PV of Year 1 Div.	Year 2 Div.	(1+k)^2	PV of Year 2 Div.	Year 3 Div.	(1+k)^3	PV of Year 3 Div.	Year 4 Div.	(1+k)^4	PV of Year 4 Div.	Year 5 Div.	(1+k)^5	PV of Year 5 Div.	Year 6 Div.	Year 5 Stock Price	PV of Year 5 Stock Price	Current Stock Price	CHECK
	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
AEP	2.55	1.09	2.33	2.69	1.20	2.25	2.85	1.31	2.17	3.01	1.44	2.09	3.17	1.57	2.02	3.35	86.68	55.07	65.92	0.00
EE	1.37	1.08	1.27	1.45	1.17	1.24	1.52	1.26	1.21	1.60	1.36	1.18	1.68	1.47	1.15	1.77	63.82	43.48	49.53	0.00
IDA	2.41	1.08	2.24	2.51	1.16	2.16	2.61	1.25	2.09	2.72	1.34	2.03	2.83	1.44	1.96	2.94	104.91	72.70	83.18	0.00
NEE	4.64	1.11	4.17	5.05	1.24	4.08	5.49	1.38	3.99	5.98	1.53	3.90	6.51	1.70	3.82	7.08	227.76	133.66	153.61	0.00
OTTR	1.40	1.12	1.25	1.53	1.25	1.22	1.66	1.39	1.20	1.81	1.55	1.17	1.98	1.74	1.14	2.15	61.34	35.35	41.33	0.00
PNW	2.86	1.09	2.62	3.01	1.19	2.53	3.18	1.30	2.44	3.35	1.42	2.36	3.54	1.55	2.28	3.73	100.62	64.77	76.99	0.00
PNM	1.10	1.11	0.99	1.18	1.22	0.97	1.27	1.35	0.94	1.37	1.50	0.91	1.47	1.65	0.89	1.58	51.17	30.94	35.64	0.00
POR	1.40	1.10	1.28	1.48	1.20	1.24	1.57	1.31	1.20	1.67	1.44	1.16	1.77	1.57	1.12	1.87	53.56	34.02	40.02	0.00

Sources and Notes:

[1] ROE Attachment 12
[2] ROE Attachment 12
[3] = [2] / [1]
[4] ROE Attachment 11
[5] = [3] x (1 + 0.5 x [4])
[6] if [4] is less than Group Avg. less St. Dev. (4.81%), then equal to 4.81%',
if [4] is greater than Group Avg. plu St. Dev. (8.14%), then equal to 8.14%
else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek functior
Adjustment for Flotation costs: ROE = [7] - [5] + [5]/(1-F)
[8] = [1] x [5]
[9] = (1 + [7])^1
[10] = [8] / [9]
[11] = [8] x (1 + [4])
[12] = (1 + [7])^2
[13] = [11] / [12]
(continued)

Sources and Notes, Continued:

[14] = [11] x (1 + [4])
[15] = (1 + [7])^3
[16] = [14] / [15]
[17] = [14] x (1 + [4])
[18] = (1 + [7])^4
[19] = [17] / [18]
[20] = [17] x (1 + [4])
[21] = (1 + [7])^5
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

Constant Growth Rate DCF Analysis - Combination Proxy Group

Company	Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate	Low Expected Dividend Yield	Mean Expected Dividend Yield	High Expected Dividend Yield	Low ROE	Mean ROE	High ROE
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
ALLETE INC	ALE	68.91	2.24	3.25%	4.50%	5.53%	6.10%	3.32%	3.34%	3.35%	7.82%	8.87%	9.45%
ALLIANT ENERGY CORP	LNT	38.79	1.34	3.45%	5.30%	5.75%	6.50%	3.55%	3.55%	3.57%	8.85%	9.30%	10.07%
CMS ENERGY CORP	CMS	43.07	1.43	3.32%	6.30%	7.28%	8.50%	3.42%	3.44%	3.46%	9.72%	10.72%	11.96%
DTE ENERGY CO	DTE	101.58	3.53	3.47%	5.58%	6.03%	6.50%	3.57%	3.58%	3.59%	9.15%	9.61%	10.09%
DUKE ENERGY CORP	DUK	76.15	3.56	4.68%	3.70%	4.15%	4.50%	4.76%	4.77%	4.78%	8.46%	8.92%	9.28%
NORTHWESTERN CORP	NWE	51.41	2.20	4.28%	2.40%	3.34%	4.50%	4.33%	4.35%	4.38%	6.73%	7.69%	8.88%
OGE ENERGY CORP	OGE	31.30	1.33	4.25%	2.50%	4.77%	6.00%	4.30%	4.35%	4.38%	6.80%	9.12%	10.38%
Mean				3.81%	4.33%	5.26%	6.09%	3.89%	3.91%	3.93%	8.22%	9.18%	10.01%
Required ROE including flotation cost adjustment											8.33%	9.29%	10.13%
Flotation Costs											2.85%		

Sources and Notes:
[1] ROE Attachment 14
[2] ROE Attachment 13
[3] = [2] / [1]
[4] ROE Attachment 13
[5] ROE Attachment 13
[6] ROE Attachment 13
[7] = [3] x (1 + 0.5 x [4])
[8] = [3] x (1 + 0.5 x [5])
[9] = [3] x (1 + 0.5 x [6])
[10] = [4] + [7]
[11] = [5] + [8]
[12] = [6] + [9]

Two Growth Rate DCF Analysis - Combination Proxy Group
Mean Growth Rates

Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Mean Projected Growth Rate	Mean Expected Dividend Yield	Second Growth Rate		Mean Expected ROE
	[1]	[2]	[3]	[4]	[5]	[6]		[7]
ALE	68.91	2.24	3.25%	5.53%	3.34%	5.53%		8.87%
LNT	38.79	1.34	3.45%	5.75%	3.55%	5.75%		9.30%
CMS	43.07	1.43	3.32%	7.28%	3.44%	6.47%		10.03%
DTE	101.58	3.53	3.47%	6.03%	3.58%	6.03%		9.61%
DUK	76.15	3.56	4.68%	4.15%	4.77%	4.15%		8.92%
NWE	51.41	2.20	4.28%	3.34%	4.35%	4.06%		8.28%
OGE	31.30	1.33	4.25%	4.77%	4.35%	4.77%		9.12%
Mean			3.81%	5.26%	3.91%	5.25%		9.16%
With Flotation Costs								9.28%
		Average		5.26%				
		Std. Dev.		1.20%			Flotation Costs (F)	2.85%
		Avg. less St. Dev.		4.06%				
		Avg. plus St. Dev		6.47%				

Ticker	Year 1 Div.	(1+k)^1	PV of Year 1 Div.	Year 2 Div.	(1+k)^2	PV of Year 2 Div.	Year 3 Div.	(1+k)^3	PV of Year 3 Div.	Year 4 Div.	(1+k)^4	PV of Year 4 Div.	Year 5 Div.	(1+k)^5	PV of Year 5 Div.	Year 6 Div.	Year 5 Stock Price	PV of Year 5 Stock Price	Current Stock Price	CHECK
	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
ALE	2.30	1.09	2.11	2.43	1.19	2.05	2.56	1.29	1.99	2.71	1.41	1.93	2.86	1.53	1.87	3.01	90.20	58.96	68.90	(0.00)
LNT	1.38	1.09	1.26	1.46	1.19	1.22	1.54	1.31	1.18	1.63	1.43	1.14	1.72	1.56	1.10	1.82	51.30	32.88	38.79	0.00
CMS	1.48	1.10	1.35	1.59	1.21	1.31	1.71	1.33	1.28	1.83	1.47	1.25	1.96	1.61	1.22	2.11	59.12	36.66	43.07	(0.00)
DTE	3.64	1.10	3.32	3.86	1.20	3.21	4.09	1.32	3.10	4.33	1.44	3.00	4.60	1.58	2.91	4.87	136.11	86.05	101.58	0.00
DUK	3.63	1.09	3.34	3.78	1.19	3.19	3.94	1.29	3.05	4.10	1.41	2.92	4.28	1.53	2.79	4.45	93.30	60.86	76.15	0.00
NWE	2.24	1.08	2.07	2.31	1.17	1.97	2.39	1.27	1.88	2.47	1.37	1.80	2.55	1.49	1.71	2.64	62.49	41.99	51.41	0.00
OGE	1.36	1.09	1.25	1.43	1.19	1.20	1.49	1.30	1.15	1.57	1.42	1.10	1.64	1.55	1.06	1.72	39.51	25.54	31.30	0.00

Sources and Notes:
[1] ROE Attachment 14
[2] ROE Attachment 13
[3] = [2] / [1]
[4] ROE Attachment 13
[5] = [3] x (1 + 0.5 x [4])
[6] if [4] is less than Group Avg. less St. Dev. (4.06%), then equal to 4.06%',
if [4] is greater than Group Avg. plu St. Dev. (6.47%), then equal to 6.47%
else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek functior
Adjustment for Flotation costs: ROE = [7] - [5] + [5]/(1-F)
[8] = [1] x [5]
[9] = (1 + [7])^1
[10] = [8] / [9]
[11] = [8] x (1 + [4])
[12] = (1 + [7])^2
[13] = [11] / [12]
(continued)

Sources and Notes, Continued:
[14] = [11] x (1 + [4])
[15] = (1 + [7])^3
[16] = [14] / [15]
[17] = [14] x (1 + [4])
[18] = (1 + [7])^4
[19] = [17] / [18]
[20] = [17] x (1 + [4])
[21] = (1 + [7])^5
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

Two Growth Rate DCF Analysis - Combination Proxy Group
Low Growth Rates

Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Low Projected Growth Rate	Low Expected Dividend Yield	Second Growth Rate		Low Expected ROE
	[1]	[2]	[3]	[4]	[5]	[6]		[7]
ALE	68.91	2.24	3.25%	4.50%	3.32%	4.50%		7.82%
LNT	38.79	1.34	3.45%	5.30%	3.55%	5.30%		8.85%
CMS	43.07	1.43	3.32%	6.30%	3.42%	5.73%		9.24%
DTE	101.58	3.53	3.47%	5.58%	3.57%	5.58%		9.15%
DUK	76.15	3.56	4.68%	3.70%	4.76%	3.70%		8.46%
NWE	51.41	2.20	4.28%	2.40%	4.33%	2.92%		7.15%
OGE	31.30	1.33	4.25%	2.50%	4.30%	2.92%		7.14%
Mean			3.81%	4.33%	3.89%	4.38%		8.26%
With Flotation Costs								8.37%
		Average		4.33%				
		Std. Dev.		1.41%			Flotation Costs (F)	2.85%
		Avg. less St. Dev.		2.92%				
		Avg. plus St. Dev		5.73%				

Ticker	Year 1 Div.	(1+k)^1	PV of Year 1 Div.	Year 2 Div.	(1+k)^2	PV of Year 2 Div.	Year 3 Div.	(1+k)^3	PV of Year 3 Div.	Year 4 Div.	(1+k)^4	PV of Year 4 Div.	Year 5 Div.	(1+k)^5	PV of Year 5 Div.	Year 6 Div.	Year 5 Stock Price	PV of Year 5 Stock Price	Current Stock Price	CHECK
	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
ALE	2.29	1.08	2.12	2.39	1.16	2.06	2.50	1.25	2.00	2.61	1.35	1.93	2.73	1.46	1.87	2.85	85.87	58.92	68.91	0.00
LNT	1.38	1.09	1.26	1.45	1.18	1.22	1.53	1.29	1.18	1.61	1.40	1.14	1.69	1.53	1.11	1.78	50.21	32.87	38.79	0.00
CMS	1.48	1.09	1.35	1.57	1.19	1.31	1.67	1.30	1.28	1.77	1.42	1.24	1.88	1.56	1.21	2.00	57.05	36.67	43.07	0.00
DTE	3.63	1.09	3.32	3.83	1.19	3.22	4.04	1.30	3.11	4.27	1.42	3.01	4.51	1.55	2.91	4.76	133.27	86.02	101.58	0.00
DUK	3.63	1.08	3.34	3.76	1.18	3.20	3.90	1.28	3.06	4.04	1.38	2.92	4.19	1.50	2.79	4.35	91.32	60.84	76.15	0.00
NWE	2.23	1.07	2.08	2.28	1.15	1.99	2.33	1.23	1.90	2.39	1.32	1.81	2.45	1.41	1.73	2.51	59.19	41.91	51.41	0.00
OGE	1.35	1.07	1.26	1.38	1.15	1.20	1.41	1.23	1.15	1.45	1.32	1.10	1.49	1.41	1.05	1.52	36.06	25.54	31.30	0.00

Sources and Notes:

[1] ROE Attachment 14
[2] ROE Attachment 13
[3] = [2] / [1]
[4] ROE Attachment 13
[5] = [3] x (1 + 0.5 x [4])
[6] if [4] is less than Group Avg. less St. Dev. (2.92%), then equal to 2.92%',
if [4] is greater than Group Avg. plu St. Dev. (5.73%), then equal to 5.73%
else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek functior
Adjustment for Flotation costs: ROE = [7] - [5] + [5]/(1-F)
[8] = [1] x [5]
[9] = (1 + [7])^1
[10] = [8] / [9]
[11] = [8] x (1 + [4])
[12] = (1 + [7])^2
[13] = [11] / [12]
(continued)

Sources and Notes, Continued:

[14] = [11] x (1 + [4])
[15] = (1 + [7])^3
[16] = [14] / [15]
[17] = [14] x (1 + [4])
[18] = (1 + [7])^4
[19] = [17] / [18]
[20] = [17] x (1 + [4])
[21] = (1 + [7])^5
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

Two Growth Rate DCF Analysis - Combination Proxy Group
High Growth Rates

Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	High Projected Growth Rate	High Expected Dividend Yield	Second Growth Rate	High Expected ROE
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
ALE	68.91	2.24	3.25%	6.10%	3.35%	6.10%	9.45%
LNT	38.79	1.34	3.45%	6.50%	3.57%	6.50%	10.07%
CMS	43.07	1.43	3.32%	8.50%	3.46%	7.35%	10.98%
DTE	101.58	3.53	3.47%	6.50%	3.59%	6.50%	10.09%
DUK	76.15	3.56	4.68%	4.50%	4.78%	4.82%	9.54%
NWE	51.41	2.20	4.28%	4.50%	4.38%	4.82%	9.14%
OGE	31.30	1.33	4.25%	6.00%	4.38%	6.00%	10.38%
Mean			3.81%	6.09%	3.93%	6.01%	9.95%
With Flotation Costs							10.06%
		Average		6.09%			
		Std. Dev.		1.27%		Flotation Costs (F)	2.85%
		Avg. less St. Dev.		4.82%			
		Avg. plus St. Dev		7.35%			

Ticker	Year 1 Div.	(1+k)^1	PV of Year 1 Div.	Year 2 Div.	(1+k)^2	PV of Year 2 Div.	Year 3 Div.	(1+k)^3	PV of Year 3 Div.	Year 4 Div.	(1+k)^4	PV of Year 4 Div.	Year 5 Div.	(1+k)^5	PV of Year 5 Div.	Year 6 Div.	Year 5 Stock Price	PV of Year 5 Stock Price	Current Stock Price	CHECK
	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
ALE	2.31	1.09	2.11	2.45	1.20	2.04	2.60	1.31	1.98	2.76	1.44	1.92	2.93	1.57	1.86	3.10	92.65	58.99	68.91	0.00
LNT	1.38	1.10	1.26	1.47	1.21	1.22	1.57	1.33	1.18	1.67	1.47	1.14	1.78	1.62	1.10	1.90	53.14	32.90	38.79	0.00
CMS	1.49	1.11	1.34	1.62	1.23	1.31	1.75	1.37	1.28	1.90	1.52	1.26	2.07	1.68	1.23	2.24	61.71	36.65	43.07	0.00
DTE	3.64	1.10	3.31	3.88	1.21	3.20	4.13	1.33	3.10	4.40	1.47	3.00	4.69	1.62	2.90	4.99	139.18	86.08	101.59	0.00
DUK	3.64	1.10	3.32	3.80	1.20	3.17	3.98	1.31	3.02	4.15	1.44	2.89	4.34	1.58	2.75	4.54	96.17	60.99	76.15	(0.00)
NWE	2.25	1.09	2.06	2.35	1.19	1.97	2.46	1.30	1.89	2.57	1.42	1.81	2.68	1.55	1.73	2.80	64.95	41.95	51.41	(0.00)
OGE	1.37	1.10	1.24	1.45	1.22	1.19	1.54	1.34	1.14	1.63	1.48	1.10	1.73	1.64	1.06	1.83	41.89	25.57	31.30	0.00

Sources and Notes:
[1] ROE Attachment 14
[2] ROE Attachment 13
[3] = [2] / [1]
[4] ROE Attachment 13
[5] = [3] x (1 + 0.5 x [4])
[6] if [4] is less than Group Avg. less St. Dev. (4.82%), then equal to 4.82%',
if [4] is greater than Group Avg. plu St. Dev. (7.35%), then equal to 7.35%
else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek functior
Adjustment for Flotation costs: ROE = [7] - [5] + [5]/(1-F)
[8] = [1] x [5]
[9] = (1 + [7])^1
[10] = [8] / [9]
[11] = [8] x (1 + [4])
[12] = (1 + [7])^2
[13] = [11] / [12]
(continued)

Sources and Notes, Continued:
[14] = [11] x (1 + [4])
[15] = (1 + [7])^3
[16] = [14] / [15]
[17] = [14] x (1 + [4])
[18] = (1 + [7])^4
[19] = [17] / [18]
[20] = [17] x (1 + [4])
[21] = (1 + [7])^5
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

Projected Growth Rates
Electric Proxy Group

Company	Ticker	Zacks	Thomson	Value Line	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate	Annualized Dividend
		[1]	[2]	[3]	[4]	[5]	[6]	[7]
AMERICAN ELECTRIC POWER CO	AEP	5.40%	5.63%	4.50%	4.50%	5.18%	5.63%	2.48
EL PASO ELECTRIC CO	EE	5.10%	5.20%	5.00%	5.00%	5.10%	5.20%	1.34
IDACORP INC	IDA	4.10%	3.10%	3.50%	3.10%	3.57%	4.10%	2.36
NEXTERA ENERGY INC	NEE	7.90%	8.85%	8.50%	7.90%	8.42%	8.85%	4.44
OTTER TAIL CORP	OTTR	na	9.00%	7.00%	7.00%	8.00%	9.00%	1.34
PINNACLE WEST CAPITAL CORP	PNW	3.00%	3.63%	5.50%	3.00%	4.04%	5.50%	2.78
PNM RESOURCES INC	PNM	5.80%	5.80%	7.50%	5.80%	6.37%	7.50%	1.06
PORTLAND GENERAL ELECTRIC CO	POR	2.90%	3.50%	6.00%	2.90%	4.13%	6.00%	1.36
Average		4.89%	5.59%	5.94%	4.90%	5.60%	6.47%	

Sources and notes:
[1] Zacks Investment Research
[2] Thomson Financial Network; Accessed via Yahoo! Finance
[3] Value Line
[4] = min([1], [2], [3])
[5] = average([1], [2], [3])
[6] = max([1], [2], [3])

30-Day Average Closing Prices and Current Dividends
Electric Proxy Group

	AEP	EE	IDA	NEE	OTTR	PNW	PNM	POR
30 Day Average Closing Stock Price	65.91	49.53	83.18	153.61	41.33	76.98	35.64	40.02
Daily Closing Prices								
2/6/2018	64.91	49.50	81.75	149.56	39.92	75.16	34.65	40.09
2/7/2018	64.45	49.70	82.25	148.09	40.15	75.16	34.45	40.10
2/8/2018	63.38	49.50	82.03	145.29	39.95	74.34	33.80	39.75
2/9/2018	64.72	50.75	83.57	148.10	41.30	76.29	35.00	40.47
2/12/2018	64.80	50.70	83.33	150.00	40.95	76.73	35.20	40.48
2/13/2018	65.58	50.80	83.47	151.07	41.65	76.82	34.95	40.43
2/14/2018	65.30	50.00	82.80	150.08	40.60	76.09	34.60	39.94
2/15/2018	66.68	50.85	84.72	154.43	41.55	78.06	35.60	40.96
2/16/2018	67.26	51.30	85.27	156.05	42.05	78.69	35.75	41.20
2/20/2018	66.37	50.25	83.70	153.81	41.35	77.20	35.30	40.22
2/21/2018	65.58	49.90	82.61	151.76	40.95	76.10	35.45	39.96
2/22/2018	65.68	49.80	82.90	152.31	40.90	76.74	35.45	40.10
2/23/2018	67.37	50.55	84.98	156.26	42.00	80.15	36.50	41.08
2/26/2018	66.97	50.50	83.91	154.65	41.50	80.28	36.30	40.62
2/27/2018	65.95	49.05	82.45	151.68	40.75	77.94	35.50	40.16
2/28/2018	65.58	48.60	81.05	152.15	39.80	76.96	35.20	39.73
3/1/2018	65.62	48.60	81.48	153.23	39.90	77.52	35.40	39.92
3/2/2018	65.18	48.60	81.61	152.85	40.00	76.92	35.85	39.74
3/5/2018	66.49	49.40	82.78	155.02	40.60	78.05	36.05	40.29
3/6/2018	65.50	48.55	81.86	153.26	40.35	76.30	35.35	39.40
3/7/2018	64.92	48.75	81.36	153.05	40.75	75.43	35.10	39.25
3/8/2018	65.30	48.75	81.45	154.31	41.45	75.97	35.45	39.23
3/9/2018	65.65	48.50	81.95	154.81	41.80	76.38	35.70	39.18
3/12/2018	65.87	48.65	83.32	154.39	42.40	76.32	36.20	39.41
3/13/2018	66.04	48.35	82.98	154.67	42.25	76.42	36.15	39.33
3/14/2018	66.59	48.90	83.61	158.01	42.50	76.78	36.55	39.52
3/15/2018	66.99	48.70	84.03	158.14	42.80	77.05	36.65	39.46
3/16/2018	67.81	49.60	86.10	161.04	43.35	77.97	37.00	40.05
3/19/2018	67.45	49.45	86.23	159.93	43.20	77.73	37.10	40.34
3/20/2018	67.45	49.35	85.85	160.42	43.15	77.99	37.00	40.22

Source: Yahoo! Finance

Projected Growth Rates
Combination Proxy Group

Company	Ticker	Zacks	Thomson	Value Line	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate	Annualized Dividend
		[1]	[2]	[3]	[4]	[5]	[6]	[7]
ALLETE INC		6.10%	6.00%	4.50%	4.50%	5.53%	6.10%	2.24
ALLIANT ENERGY CORP		5.30%	5.45%	6.50%	5.30%	5.75%	6.50%	1.34
CMS ENERGY CORP		6.30%	7.04%	8.50%	6.30%	7.28%	8.50%	1.43
DTE ENERGY CO		6.00%	5.58%	6.50%	5.58%	6.03%	6.50%	3.53
DUKE ENERGY CORP		3.70%	4.24%	4.50%	3.70%	4.15%	4.50%	3.56
NORTHWESTERN CORP		2.40%	3.12%	4.50%	2.40%	3.34%	4.50%	2.20
OGE ENERGY CORP		6.00%	5.80%	2.50%	2.50%	4.77%	6.00%	1.33
Average		5.11%	5.32%	5.36%	4.33%	5.26%	6.09%	

Sources and notes:
[1] Zacks Investment Research
[2] Thomson Financial Network; Accessed via Yahoo! Finance
[3] Value Line
[4] = min([1], [2], [3])
[5] = average([1], [2], [3])
[6] = max([1], [2], [3])

30-Day Average Closing Prices and Current Dividends
Combination Proxy Group

	ALE	LNT	CMS	DTE	DUK	NWE	OGE
30 Day Average Closing Stock Price	68.91	38.79	43.07	101.58	76.15	51.41	31.30
Daily Closing Prices							
2/6/2018	68.37	37.51	42.16	99.36	74.49	50.89	30.28
2/7/2018	68.73	37.50	42.16	99.27	74.40	50.81	30.28
2/8/2018	68.56	37.14	41.77	98.49	74.32	50.33	29.60
2/9/2018	69.89	38.42	42.79	101.06	76.10	52.13	30.39
2/12/2018	69.71	38.48	42.88	101.25	76.81	52.22	30.87
2/13/2018	69.45	38.63	43.05	102.21	77.08	51.82	30.96
2/14/2018	68.05	38.11	42.90	101.23	75.48	50.92	30.78
2/15/2018	68.48	39.05	43.74	103.15	76.20	51.59	31.34
2/16/2018	69.34	39.75	44.20	105.22	76.70	52.27	31.56
2/20/2018	68.74	39.14	43.36	103.20	75.69	51.32	31.21
2/21/2018	67.80	38.62	43.02	101.90	75.33	51.15	30.82
2/22/2018	68.19	38.60	43.01	101.86	75.54	51.19	31.47
2/23/2018	69.98	39.42	43.86	104.70	77.22	52.50	32.95
2/26/2018	69.44	39.53	43.77	103.76	77.92	51.74	32.28
2/27/2018	68.25	38.80	42.75	102.03	76.33	51.11	31.58
2/28/2018	68.15	38.65	42.45	100.78	75.34	51.08	31.34
3/1/2018	68.60	38.49	42.36	100.73	75.56	51.05	31.54
3/2/2018	68.58	38.22	42.59	100.79	75.35	51.06	31.19
3/5/2018	68.53	38.93	43.29	102.57	77.49	51.93	31.92
3/6/2018	67.19	38.17	42.69	101.20	75.86	51.04	31.20
3/7/2018	67.86	38.06	42.49	99.92	75.25	50.84	30.88
3/8/2018	67.70	38.32	42.56	100.40	75.99	50.89	31.22
3/9/2018	68.08	38.71	42.86	100.53	76.13	51.07	31.35
3/12/2018	68.71	39.21	43.09	100.91	76.55	51.67	31.45
3/13/2018	68.68	39.30	42.96	100.93	76.47	51.42	31.52
3/14/2018	69.19	39.54	43.32	101.77	77.00	51.12	31.79
3/15/2018	69.48	39.66	43.71	101.72	76.74	51.16	31.62
3/16/2018	71.07	40.13	44.28	102.27	77.59	51.90	32.00
3/19/2018	71.22	39.83	43.98	102.19	77.04	52.34	31.89
3/20/2018	71.14	39.68	43.99	102.15	76.43	51.87	31.78

Source: Yahoo! Finance

DOC CAPM Analysis

	Line No.	Formula/Note	EPG	CPG
Risk-free Rate	[1]	ROE Attachment 16	3.01%	3.01%
Thomson First Call Projected S&P 500 Earnings Growth Rate	[2]	ROE Attachment 17	12.00%	12.00%
Dividend Yield on S&P 500	[3]	ROE Attachment 18	1.80%	1.80%
Dividend yield on S&P 500 with Half Years' Worth of Growth	[4]	=[3] x (1 + 0.5 x [2])	1.91%	1.91%
DCF Required Market Return	[5]	= [2] + [4]	13.91%	13.91%
β	[6]	ROE Attachment 19	0.73	0.71
Required Return for CPEM (Simple CAPM)	[7]	= [1] + [6] x ([5]-[1])	10.91%	10.80%
Flotation Cost Adjustment	[8]	ROE Attachment 3	0.10%	0.10%
Simple CAPM with Flotation Costs	[9]	= [7] + [8]	11.01%	10.90%

20-Year Treasury Bond Yields

Date	Rate (%)
2018-02-05	2.92
2018-02-06	2.94
2018-02-07	3.01
2018-02-08	3.03
2018-02-09	3.02
2018-02-12	3.02
2018-02-13	2.99
2018-02-14	3.07
2018-02-15	3.04
2018-02-16	3.02
2018-02-20	3.04
2018-02-21	3.11
2018-02-22	3.09
2018-02-23	3.04
2018-02-26	3.03
2018-02-27	3.06
2018-02-28	3.02
2018-03-01	2.97
2018-03-02	3.02
2018-03-05	3.04
2018-03-06	3.03
2018-03-07	3.04
2018-03-08	3.01
2018-03-09	3.04
2018-03-12	3.00
2018-03-13	2.98
2018-03-14	2.94
2018-03-15	2.94
2018-03-16	2.96
2018-03-19	2.97
Average	3.01

Source:
Federal Reserve Bank of St. Louis

Docket No. E002/M-17-797
ROE Appendix
ROE Attachment 17

American Electric Power Company , Inc. (AEP)

NYSE - Nasdaq Real Time Price. Currency in USD

Add to watchlist

Quote Lookup

67.36 -0.09 (-0.13%)

As of 11:06AM EDT. Market open.

Currency in USD

Earnings Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	10	8	19	17
Avg. Estimate	1	0.83	3.89	4.12
Low Estimate	0.97	0.75	3.84	4.02
High Estimate	1.03	0.99	3.96	4.21
Year Ago EPS	0.96	0.75	3.68	3.89

Revenue Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	6	5	12	11
Avg. Estimate	4.06B	3.98B	15.88B	16.35B
Low Estimate	3.73B	3.66B	14.21B	14.55B
High Estimate	4.3B	4.28B	17.14B	17.73B
Year Ago Sales	3.9B	3.6B	15.4B	15.88B
Sales Growth (year/est)	4.20%	10.50%	3.10%	3.00%

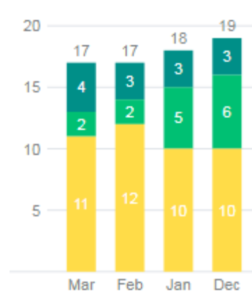
Earnings History	3/30/2017	6/29/2017	9/29/2017	12/30/2017
EPS Est.	0.95	0.82	1.16	0.79
EPS Actual	0.96	0.75	1.1	0.85
Difference	0.01	-0.07	-0.06	0.06
Surprise %	1.10%	-8.50%	-5.20%	7.60%

EPS Trend	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	1	0.83	3.89	4.12
7 Days Ago	1	0.83	3.89	4.12
30 Days Ago	1.03	0.82	3.89	4.11

People Also Watch

Symbol	Last Price	Change	% Change
SO Southern Company (The)	44.03	+0.18	+0.40%
D Dominion Energy, Inc.	68.40	-0.05	-0.07%
DUK Duke Energy Corporation (Holdin	76.53	+0.10	+0.13%
FE FirstEnergy Corporation	33.98	+0.24	+0.71%
ED Consolidated Edison, Inc.	76.94	+0.05	+0.07%

Recommendation Trends >



Strong Buy
Buy
Hold
Underperform
Sell

Recommendation Rating >

2.2

Docket No. E002/M-17-797
ROE Appendix
ROE Attachment 17

EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	N/A	1	1	N/A
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

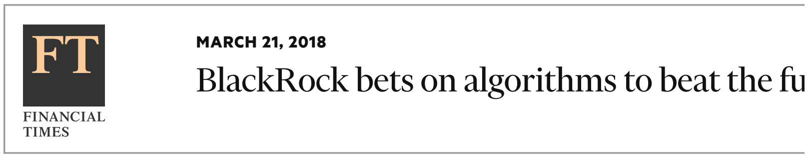
Growth Estimates	AEP	Industry	Sector	S&P 500
Current Qtr.	4.20%	N/A	N/A	0.36
Next Qtr.	10.70%	N/A	N/A	0.37
Current Year	5.70%	N/A	N/A	0.20
Next Year	5.90%	N/A	N/A	0.11
Next 5 Years (per annum)	5.63%	N/A	N/A	0.12
Past 5 Years (per annum)	4.92%	N/A	N/A	N/A

Average 72.00

Low 64.00 High 77.00
Current 67.36

Docket No. E002/M-17-797
ROE Appendix
ROE Attachment 18

S&P 500 Dividend Yield



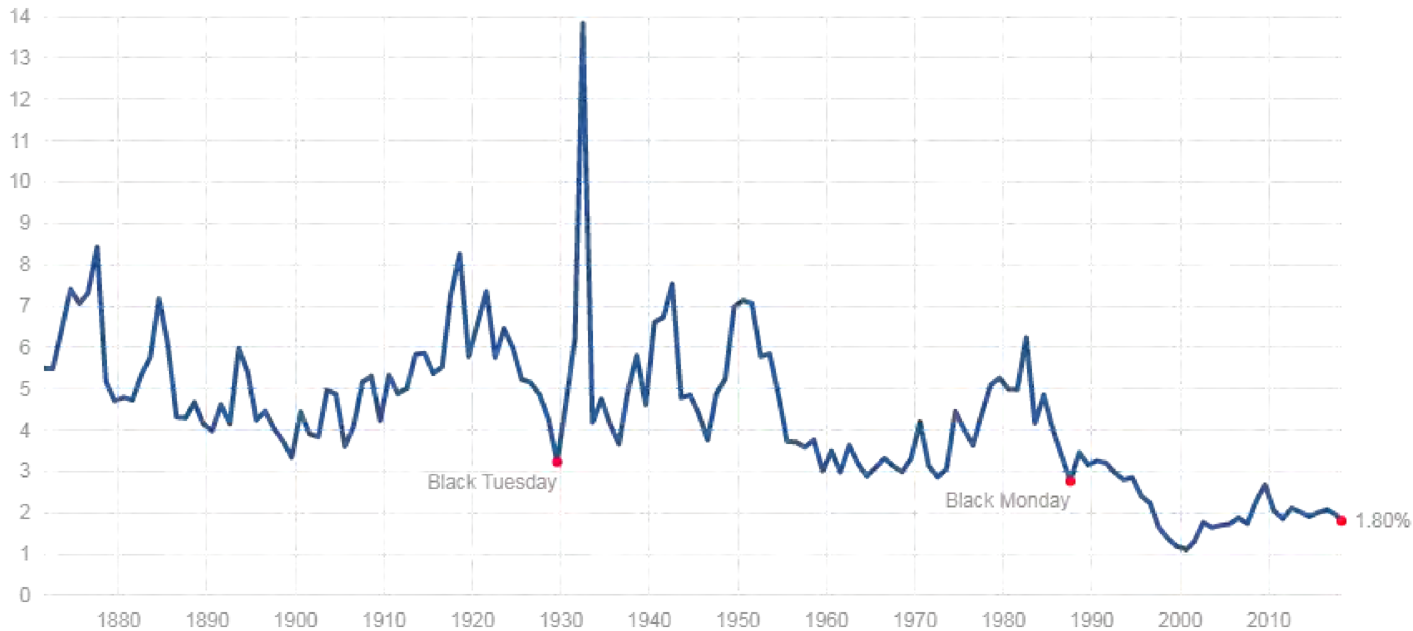


Chart Table Share

Current Yield : 1.80% +0.34 bps
4:00 pm EDT, Wed Mar 21

Mean: 4.36%
Median: 4.31%
Min: 1.11% (Aug 2000)
Max: 13.84% (Jun 1932)

S&P 500 dividend yield — (12 month dividend per share)/price.

Yields following December 2017 (including the current yield) are estimated based on 12 month dividends through December 2017, as reported by S&P.

Sources:

- Standard & Poor's for current S&P 500 Dividend Yield.
- Robert Shiller and his book Irrational Exuberance for historic S&P 500 Dividend Yields.

See also

- S&P 500 Dividend
- S&P 500 Dividend Growth

Docket No. E002/M-17-797
ROE Appendix
ROE Attachment 18

Value Line Betas
For Members of
DOC Proxy Groups

Ticker	EPG	CPG
AEP	0.65	
EE	0.80	
IDA	0.70	
NEE	0.65	
OTTR	0.85	
PNW	0.70	
PNM	0.75	
POR	0.70	
ALE		0.75
LNT		0.70
CMS		0.65
DTE		0.65
DUK		0.60
NWE		0.70
OGE		0.95
Average	0.73	0.71

Source:
Value Line

Blue Chip Financial Forecasts®

Top Analysts' Forecasts Of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them

Vol. 36, No. 6, June 1, 2017

Wolters Kluwer

Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2019 through 2023 and averages for the five-year periods 2019-2023 and 2024-2028. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

		-----------Average For The Year------------					Five-Year Averages	
Interest Rates		**2019**	**2020**	**2021**	**2022**	**2023**	**2019-2023**	**2024-2028**
1. Federal Funds Rate	**CONSENSUS**	**2.6**	**2.9**	**2.9**	**2.9**	**2.9**	**2.8**	**3.0**
	Top 10 Average	3.1	3.5	3.4	3.5	3.5	3.4	3.5
	Bottom 10 Average	2.0	2.3	2.3	2.3	2.4	2.3	2.4
2. Prime Rate	**CONSENSUS**	**5.6**	**5.9**	**5.9**	**5.9**	**5.9**	**5.8**	**6.0**
	Top 10 Average	6.1	6.5	6.5	6.5	6.5	6.4	6.5
	Bottom 10 Average	5.0	5.3	5.3	5.2	5.3	5.2	5.4
3. LIBOR, 3-Mo.	**CONSENSUS**	**2.9**	**3.1**	**3.2**	**3.1**	**3.2**	**3.1**	**3.2**
	Top 10 Average	3.4	3.7	3.7	3.7	3.8	3.7	3.8
	Bottom 10 Average	2.4	2.6	2.6	2.5	2.6	2.5	2.6
4. Commercial Paper, 1-Mo.	**CONSENSUS**	**2.7**	**3.0**	**3.0**	**3.0**	**3.1**	**3.0**	**3.1**
	Top 10 Average	3.2	3.5	3.5	3.6	3.6	3.5	3.6
	Bottom 10 Average	2.2	2.5	2.5	2.4	2.5	2.4	2.6
5. Treasury Bill Yield, 3-Mo.	**CONSENSUS**	**2.5**	**2.8**	**2.8**	**2.8**	**2.9**	**2.8**	**2.9**
	Top 10 Average	3.1	3.4	3.4	3.4	3.5	3.3	3.5
	Bottom 10 Average	1.9	2.2	2.3	2.2	2.3	2.2	2.3
6. Treasury Bill Yield, 6-Mo.	**CONSENSUS**	**2.6**	**2.9**	**3.0**	**3.0**	**3.0**	**2.9**	**3.0**
	Top 10 Average	3.2	3.6	3.5	3.6	3.6	3.5	3.6
	Bottom 10 Average	2.0	2.4	2.4	2.4	2.4	2.3	2.4
7. Treasury Bill Yield, 1-Yr.	**CONSENSUS**	**2.8**	**3.1**	**3.1**	**3.1**	**3.1**	**3.0**	**3.2**
	Top 10 Average	3.4	3.7	3.7	3.7	3.7	3.6	3.7
	Bottom 10 Average	2.1	2.5	2.5	2.5	2.5	2.4	2.5
8. Treasury Note Yield, 2-Yr.	**CONSENSUS**	**2.9**	**3.2**	**3.3**	**3.3**	**3.3**	**3.2**	**3.3**
	Top 10 Average	3.5	3.9	3.9	3.9	3.9	3.8	4.0
	Bottom 10 Average	2.3	2.6	2.7	2.6	2.6	2.6	2.7
10. Treasury Note Yield, 5-Yr.	**CONSENSUS**	**3.3**	**3.5**	**3.5**	**3.6**	**3.6**	**3.5**	**3.6**
	Top 10 Average	3.9	4.2	4.2	4.2	4.2	4.1	4.3
	Bottom 10 Average	2.7	2.9	2.9	3.0	3.0	2.9	3.0
11. Treasury Note Yield, 10-Yr.	**CONSENSUS**	**3.6**	**3.8**	**3.8**	**3.9**	**3.9**	**3.8**	**3.9**
	Top 10 Average	4.2	4.5	4.4	4.5	4.5	4.4	4.6
	Bottom 10 Average	2.9	3.1	3.1	3.2	3.3	3.1	3.3
12. Treasury Bond Yield, 30-Yr.	**CONSENSUS**	**4.2**	**4.3**	**4.4**	**4.4**	**4.4**	**4.3**	**4.5**
	Top 10 Average	4.9	5.0	5.0	5.0	5.0	5.0	5.1
	Bottom 10 Average	3.5	3.7	3.7	3.8	3.8	3.7	3.8
13. Corporate Aaa Bond Yield	**CONSENSUS**	**5.2**	**5.4**	**5.4**	**5.4**	**5.5**	**5.4**	**5.5**
	Top 10 Average	5.7	5.9	5.9	6.0	5.9	5.9	6.0
	Bottom 10 Average	4.7	4.9	4.9	4.9	5.0	4.9	5.1
13. Corporate Baa Bond Yield	**CONSENSUS**	**6.1**	**6.3**	**6.3**	**6.3**	**6.3**	**6.3**	**6.4**
	Top 10 Average	6.8	7.0	6.9	7.0	6.9	6.9	7.0
	Bottom 10 Average	5.5	5.6	5.7	5.6	5.8	5.6	5.7
14. State & Local Bonds Yield	**CONSENSUS**	**4.6**	**4.7**	**4.7**	**4.7**	**4.7**	**4.7**	**4.8**
	Top 10 Average	5.1	5.3	5.2	5.3	5.3	5.2	5.3
	Bottom 10 Average	4.2	4.2	4.2	4.1	4.1	4.2	4.2
15. Home Mortgage Rate	**CONSENSUS**	**5.3**	**5.5**	**5.5**	**5.5**	**5.5**	**5.4**	**5.6**
	Top 10 Average	5.9	6.2	6.1	6.2	6.1	6.1	6.2
	Bottom 10 Average	4.6	4.8	4.8	4.7	4.9	4.8	4.9
A. FRB - Major Currency Index	**CONSENSUS**	**93.8**	**93.2**	**93.1**	**93.0**	**92.7**	**93.2**	**92.5**
	Top 10 Average	96.5	96.6	96.9	97.1	97.2	96.9	97.1
	Bottom 10 Average	91.0	89.7	89.2	88.7	88.1	89.3	88.1

		----------Year-Over-Year, % Change----------					Five-Year Averages	
		2019	**2020**	**2021**	**2022**	**2023**	**2019-2023**	**2024-2028**
B. Real GDP	**CONSENSUS**	**2.2**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.1**
	Top 10 Average	2.6	2.4	2.4	2.4	2.3	2.4	2.3
	Bottom 10 Average	1.7	1.6	1.6	1.6	1.6	1.6	1.8
C. GDP Chained Price Index	**CONSENSUS**	**2.2**	**2.1**	**2.1**	**2.0**	**2.0**	**2.1**	**2.0**
	Top 10 Average	2.5	2.3	2.3	2.2	2.2	2.3	2.3
	Bottom 10 Average	1.9	1.9	1.9	1.9	1.7	1.8	1.9
D. Consumer Price Index	**CONSENSUS**	**2.3**	**2.3**	**2.3**	**2.3**	**2.2**	**2.2**	**2.2**
	Top 10 Average	2.6	2.6	2.5	2.5	2.4	2.5	2.4
	Bottom 10 Average	1.9	2.0	2.0	2.1	1.8	2.0	2.0

Impact on CAPM Results of Using Yield on 20-Year US Treasury Bonds Versus Yield on 30-Year US Treasury Bonds

Company CAPM Analysis with Bloomberg Betas	Risk Free Rate	Bloomberg Beta	Market Return	Market Risk Premium	ROE
	[a]	[b]	[c]	[d]=[c]-[a]	[e]=[a]+[b]x[d]
Company Calculation - 30-Year US Treasury Bond	2.77%	0.565	0.1355	10.78%	8.86%
Department Recalculation - 20-Year US Treasury Bond	2.52%	0.565	0.1355	11.03%	8.75%
Difference					-0.11%

Company CAPM Analysis with Value Line Betas	Risk Free Rate	Value Line Beta	Market Return	Market Risk Premium	ROE
	[a]	[b]	[c]	[d]=[c]-[a]	[e]=[a]+[b]x[d]
Company Calculation - 30-Year US Treasury Bond	2.77%	0.7	0.1355	10.78%	10.32%
Department Recalculation - 20-Year US Treasury Bond	2.52%	0.7	0.1355	11.03%	10.24%
Difference					-0.08%

Sources:

Company Calculations from Petition, Attachment 15, Appendix 3, Schedule 4.3, page 1.

Department Recalculations use all the same data as the Company calculations, except replace the average yield on 30-year Treasury Bonds over the 30 days ending September 29, 2017 with the average yield on 20-year Treasury bonds over the same period.

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Comments

Docket No. E002/M-17-797

Dated this 2nd day of April 2018

/s/Sharon Ferguson

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