MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	May 23, 2019	Agenda Item 6**
Company	Northern States Power Company, d/b/a Xcel Energy	
Docket No.	**E-002/M-17-818**	
	In the Matter of Petition of Northern States Power Company, for Approval of the Renewable Energy Standards (RES) Rider Revenue Requirements for 2017 and 2018 and RES Adjustment Factors	

Issues

1. Should the Commission approve or modify Xcel Energy's proposed rate of return used for determining the RES Rider revenue requirement?

2. Should the Commission approve or modify Xcel Energy's proposed proration for Accumulated Deferred Income tax?

3. Should the Commission approve or modify Xcel Energy's request for approval of revenue requirements for 2017 and 2018 along with associated RES Adjustment Factors?

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Relevant Documents	**Date**
Xcel Energy – Initial Petition	November 17, 2017
Minnesota Department of Commerce - Comments	March 26, 2018
Xcel Energy – Reply Comments	May 14, 2018
Xcel Energy – Supplemental Reply Comments	May 25, 2018
Xcel Energy – Second Supplement to Reply Comments	July 16, 2018
Minnesota Department of Commerce – Response Comments	September 5, 2018

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I. Statement of the Issues

Should the Commission approve or modify Xcel Energy's proposed rate of return used for determining the RES Rider revenue requirement?

Should the Commission approve or modify Xcel Energy's proposed proration for Accumulated Deferred Income Taxes?

Should the Commission approve or modify Xcel Energy's request for approval of revenue requirements for 2017 and 2018 along with associated RES Adjustment Factors?

II. Introduction

Generally, a public utility may not change its rates without undergoing a rate case in which the Commission comprehensively reviews the utility's costs and revenues. However, the Legislature has created exceptions to this general policy, allowing a utility to implement a rider to expedite recovery of certain costs not reflected in the company's current base rates.

Minnesota (Minn.) Statute (Stat.) section (§) 216B.1645, Subdivision (Subd.) 2a **Cost recovery for utility's renewable facilities**[1] allows a utility to petition the Commission for recovery of prudently incurred investments, expenses or costs associated with facilities constructed, owned or operated by a utility to satisfy the states renewable energy objectives pursuant to Minn. Stat. § 216B.1691, provided those facilities were previously approved by the Commission.

The Renewable Energy Standard (RES) Rider is designed to allow for the automatic adjustment of charges to recover prudently-incurred investments, expenses, or costs associated with facilities constructed, owned, or operated by a utility to satisfy the RES Statute, provided those facilities were previously approved by the Commission. Originally, Xcel Energy's RES Rider contained only costs associated with the true-up of Production Tax Credits (PTC) related to energy production of Company-owned wind farms. In 2015, Xcel Energy began including costs and expenses associated with a new Company-owned wind farm, Courtenay Wind, in addition to a true-up of actual PTCs for 2015.

III. Background

On November 17, 2017, Northern States Power Company d/b/a Xcel Energy (Xcel Energy or the Company) submitted its *Petition* requesting approval of RES revenue requirements for 2017 and 2018 and proposed RES Adjustment Factors. The 2017 and 2018 RES Rider revenue requirements include costs and expenses associated with the Courtenay Wind Project and other non-PPA projects in the Company's Wind Portfolio, representing 1,150 MW of the 1,550 MW Wind Portfolio. The requested revenue requirements have changed throughout this proceeding due to 1) updated data in response to Minnesota Department of Commerce, Division of Energy Resources (Department) Information Requests; and 2) the impact of the Tax

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[1] The statute is included in its entirety in Attachment A to these briefing papers.

Cuts and Jobs Act (TCJA).[2] Originally, Xcel Energy requested revenue requirements in the amount of ($10,339,886) for 2017 and $10,469,054 for 2018, however, with the data updates and the impact of the TCJA, the updated revenue requirements requests are shown in table 1, below.

Table 1: Updated Revenue Requirements[3]

2017	2018
($12,894,094)	$22,725,222

On March 26, 2018, the Department filed its *Comments* requesting additional information on a number of topics.

On May 14, 2018, Xcel Energy filed *Reply Comments* responding to the Department's requests for additional information.

Additionally, Xcel Energy stated that the Company would address their prorated treatment of ADIT in a supplemental filing, as Xcel Energy was in the process of completing the calculations of their proposed ADIT proration methodology.[4]

On May 25, 2018, Xcel Energy filed *Supplemental Reply Comments* that provided additional detail and supporting calculations of their proposed ADIT proration methodology. On June 6, 2018, the Department met with the Company to further discuss their proposal.

On July 16, 2018, in response to the Department's June 6, 2018 request, the Company filed a *Second Supplement* to their *Reply Comments* (Second Supplement) proposing that the ADIT proration calculation be presented as a separate line item rather than being embedded in the rate base calculation. The *Second Supplement* provided a more granular breakdown of the proposed ADIT proration methodology's on project-specific revenue requirements.[5]

On September 5, 2018, the Department provided *Response Comments* to Xcel Energy's proposed ADIT proration methodology and to the Company's responses to other issues raised in the Department's initial comments.

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[2] Pub L. 115-97.

[3] Xcel Energy *Reply Comments* at 5.

[4] *Id*. at 8.

[5] Xcel Energy *Second Supplemental Reply Comments* at 1.

IV.Parties' Comments

A. Disputed Issues

1. Rate of Return

a. Background

Minn. Stat. § 216B.1645, Subd. 2a. **Cost recovery for utility's renewable facilities**. Allows a for recovery from customers for return on investment costs, Minn. Stat. § 216B.1645, Subd. 2a states:

> (1) Allows a utility to recover directly from customers on a timely basis the costs of qualifying renewable energy projects, including:
>
> (i) Return on investment…

The current ROE was established in Docket No. E-002/GR-15-826, Xcel Energy's most recent rate case (15-826 Docket). In its *Order* dated June 12, 2017, the Commission approved the Stipulation of Settlement allowing "…Xcel Energy to represent its authorized ROE as nine and two-tenths percent (9.20%) for settlement purposes…"[6] In its *Order* approving the *Settlement*, the Commission made clear that the authorized ROE that Xcel Energy 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.*[7]

Both the Company and Department agreed to use the ROE established for the TCR rider (Docket No. E-002/M-17-797) as the ROE to be used for the RES rider. The TCR rider is also scheduled for the May 23rd agenda meeting. Xcel Energy's GUIC rider involves its gas utility and will be determined separately. Since both Xcel Energy and the Department have agreed to use the ROE established in the TCR rider, staff did not provide an ROE discussion for the current proceeding. Instead, the ROE discussion from the TCR rider docket briefing papers, pages 5 through 21, is reproduced in its entirety below:

In the current *Petition*, Xcel Energy proposed to use the same capital structure, cost of long-term debt and cost of short-term debt to develop its proposed ROR as the Commission

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[6] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-15-826, Findings of Fact, Conclusions, and Order at 10, OP 2 at 68 (June 12, 2017).

[7] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-15-826, Findings of Fact, Conclusions, and Order at 22 (June 12, 2017).

approved in the 15-826 Docket, with a proposed update only to the Company's ROE. Specifically, rather than the 9.20 percent ROE authorized (for representational purposes) by the Commission in the 15-826 Docket, the Company proposed an ROE of 10.00 percent. The Company used Concentric Energy Advisors (Concentric), to perform a cost of equity analysis and determine the appropriate ROE. The results ranged from a low of 8.19 percent for the Discounted Cash Flow (DCF) method to a high of 10.78 percent for the Capital Asset Pricing Model (CAPM).

The Department and the OAG responded to the Company's proposal and provided their own recommendations as discussed below.

Regarding the cost of equity, all three parties recommended that the Commission follow the standards established in (1) *Bluefield Water Works and Improvement Co. v. Public Service Comm'n.*, 262 U. S. 695 (1923) ("*Bluefield*"); and (2) *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*"). These decisions explain that utility regulators must set rates that permit the utility the opportunity: (1) to attract capital at reasonable terms; (2) to maintain its credit rating and ensure its financial integrity; and (3) to provide a return commensurate with returns on investments having comparable risks. These rates get developed, in significant part, by setting an appropriate overall cost of capital for the utility, equal to the cost of each capital component (both debt and equity) multiplied by the percentage that the component comprises the overall capital of the utility.

1. Department Comments

The Department disagreed with Xcel Energy's proposed ROE, and instead proposed the Commission authorize an ROE of 8.99 percent.[8]

a. Methods to Determine Cost of Common Equity

The Department stated that there are a number of analytical methods that can be used to calculate a reasonable cost of equity. The methods used by the parties are:

i. Discounted Cash Flow Model

The DCF model, is a market-oriented method that requires the determination of the appropriate dividend yield and the appropriate growth rate to be used in this analysis. If annual dividends grow at a constant rate over an infinite period, the required rate of return on common equity capital can be estimated with the following formula:

The expected (required) rate of return on equity =
the expected dividend yield + the expected growth
rate in dividends.

[8] Department *Comments* at 13. The Department revised its recommendation to 8.59 percent in its *Response Comments*.

A variation of the DCF model is the Two Growth Rate DCF (TGDCF). This model is sometimes used when an analyst thinks the short-term earnings growth rate may be either unusually low or unusually high and is not expected to be sustained. To the degree that such growth rates may not be sustainable in the long-run, the TGDCF method accommodates two different growth rates: short-term and sustainable, long-term growth rates.

ii. Capital Asset Pricing Model

The CAPM defines risk as the relationship of a security's returns with the market's returns. 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 ("β"). The CAPM is expressed as follows:

$$K = r_f + \beta\,(r_m - r_f)$$

Where:

K = the required rate of return on the stock in question;
β = Beta coefficient of an individual security;
r_f = the risk-free rate of return; and
r_m = the required return on the market portfolio.

The Department states that, while the CAPM is theoretically sound, its use as a method to estimate a company's cost of equity raises some difficult analytical issues. These include 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 the required return on equity. Rather, the CAPM analysis is used only to assess and check the reasonableness of the results of its DCF analyses.

iii. Risk Premium Analysis

The Risk Premium Analysis (RPA) is based upon the theory that the cost of common equity capital is greater than the prospective company-specific cost rate for long-term debt. The cost of equity is the expected cost rate for long-term debt capital plus a premium to compensate common shareholders for the added risk of being unsecured and last-in-line in any claim on the corporation's assets and earnings. This model often assumes a relatively stable relationship (delta) over time between the cost of long-term debt and equity.

b. 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, in order to meet investor's required rate of return, the company must earn a higher percentage return on its stock issuance proceeds than investors require on their investments. 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 the DCF ROE estimate is applied directly without an adjustment for flotation costs, Xcel Energy 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 Department 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.

c. Department Recommended Return on Equity

The Department used a weighted average of its mean two-growth DCF results for its Proxy Groups. The Department argues that 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 the DCF results should be used to determine the reasonable rate of return on common equity capital for NSPM. The Department noted that 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 NSPM's electric operations, the Department assigned more weight to the electric proxy group's (EPG's) DCF result than the combination proxy group's (CPG's). However, because the companies in the CPG are primarily engaged in the provision of retail electric services, the CPG's DCF result has significant analytical value.

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

Table 2: 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%

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

2. OAG Comments

The OAG argues that Xcel Energy's proposed ROE is not commensurate with the risks of investments recovered through riders like the TCR. The OAG recommends that the Commission establish a return for the Company's TCR rider based on Xcel Energy's cost of long-term debt of 4.30 percent. The OAG also considered an ROE of 2.30 percent, which is the average yield on two-year Treasury bonds. The OAG did not present the results of traditional DCF, CAPM, or Risk Premium models to estimate the cost of equity for Xcel Energy's TCR rider.

a. Risk profiles of Riders compared to General Rate Cases

The OAG argues that the risk of investments recovered through riders is lower than the risk of investments recovered through base rates. In a traditional rate case, investments are placed into rate base and recovered through base rates. Cash flows related to those investments are incorporated into the utility's revenue requirement only after a utility files a rate case. Assuming that the investments are allowed into rate base (and thus incorporated into base rates), the cash flows related to these investments are not guaranteed and fluctuate from year to year. Cash flow deviation (either under- or over-recovery) is an expected and well-understood part of utility ratemaking. Any deviation is generally not trued-up annually, which means that there may be significant volatility in when, and how much, cash flow is received from year-to-year.

In comparison, the revenue requirement for rider investments is fully trued-up each year. While it is likely that utilities will over- or under-recover rider investments month-to-month, on an annual basis the OAG argues that there is zero risk of under-recovery because of the true-up mechanism. While investors receive no guarantees of recovery for investments recovered in base rates, investors are guaranteed a full recovery of rider investments. The only real risk is that of a temporary under-collection that will be corrected in no more than one year. This stands in stark contrast to investments that may only be recovered in base rates.

The OAG provided the following example, if a utility makes an investment outside of a test year (or if Xcel Energy makes an investment that is not included in its current MYRP), it will not be able to recover any of the related costs until its next rate case is complete. There is the risk of significant negative cash flows related to the timing of up-front investments, and additional risk because it is never certain whether a regulator will allow the costs to be recovered. In the case of an investment that is eligible for rider recovery, then the initial recovery of that investment will be nearly immediate and far more certain than if the utility (investor in the project) had to wait until a future rate case for cost recovery.

The OAG continues by stating that the difference becomes even more significant for rider investments that have already been certified by the regulator before the investments are made. For many riders, investments that are recovered through the rider have already been certified or reviewed in some format by the regulator. This significantly reduces the risk of future disallowance. These certifications significantly reduce business risk compared to investments recovered through base rates, which are normally not pre-approved or reviewed by regulators until they are presented in a rate case proceeding.

Rider investments have a fundamentally different risk profile than investments recovered in base rates. Rider investments have lower business risk (because of reduced regulatory risk) and lower cash flow risk (because of both the nearly immediate recovery of cost and the certainty that there will be full recovery of the revenue requirement, including the cost of capital). These characteristics are very different from the risks for rate base investment, and that means that a different ratemaking analysis and approach is warranted to determine what return would be "commensurate with returns on investments in other enterprises having corresponding risks."

b. Calculation of Appropriate Return

Rather than selecting a single type of debt security to provide a comparison to TCR investments, the OAG argues that the most reasonable analysis is to compare a range of debt securities. The OAG argues that one of the primary factors impacting the return on debt securities is the length of maturity. "To determine which debt securities have risks that are comparable to rider investments, it is necessary to consider the intended "length" of rider investments. In other words, how long should investments remain in a rider before they are rolled into base rates?"[9]

The OAG notes there are several theories on how to answer this question and comparing those theories to different types of debt securities can help the Commission create a range of debt security returns to compare to the TCR rider. The OAG suggest the following process:[10]

> ***<u>Creating A Floor</u>***
>
> *One theory about the "length" of rider investments is that they should be rolled into base rates at the first opportunity. This treatment would be consistent with traditional ratemaking policy. Xcel has been filing rate cases relatively frequently,*

[9] OAG *Comments* at 15.

[10] *Id*. at 16-17 (Citations Omitted).

and taking advantage of multi-year rate plans, indicating that the time between rate cases is relatively small. Applying this theory to Xcel would suggest that its rider investments should be rolled into base rates very quickly, perhaps in as little as one or two years after the investments are made. This would indicate that debt securities with maturities of one or two years would provide a reasonable comparison. In other words, a debt security with a maturity of one or two years would be relevant when considering the TCR rider, when assuming that TCR investments should be rolled into base rates after only a year or two. The return on a two-year Treasury currently is approximately 2.3 percent. This provides a reasonable floor for the range of debt security returns.

In addition to the 2.3 percent two-year Treasury, it is also valuable to keep in mind the utility's cost of short-term debt, and the cost of its available lines of credit. These sources of financing may also be reasonable comparisons to rider investments because the utility can achieve full recovery of its costs of investment in a relatively similar length as the repayment terms of these financing sources.

Creating A Ceiling

In order to provide a complete range of comparable debt security returns, it is also necessary to establish a ceiling. As explained previously, a floor was established in based upon a theory that riders should be rolled into base rates as quickly as possible [sic]. In contrast, the ceiling should be established via consideration of the longest reasonable amount of time during which it would make sense to recover an investment through a rider. In general, it is not appropriate to recover long-term investments through riders over their entire lifespan. Investments should be rolled into base rates at some point. Consistent with that reasoning, the ceiling for a rider return should not exceed the cost of the utility's longest-lived form of debt financing—its long-term debt [approximately 4.3 percent].

c. Other Jurisdictions

The OAG points out that in 2011 the state of Iowa concluded a rulemaking that determined that the "cost of debt" was the most appropriate rate of return for gas utilities' infrastructure-related capital investment riders.[11] Specifically, the OAG stated:

The rule, 199 Iowa Administrative Code 19.18(476), allows natural gas utilities to recover "amount[s] limited to annual depreciation plus a return on the undepreciated balance based upon the cost of debt."

The rulemaking involved a debate between the utility, the regulator, and consumer advocates over the appropriate rate of return to set for capital investment riders. On one end, utilities advocated for a rate of return set at the weighted average cost of capital from the utility's most recent rate case. On the other end, the Iowa Office of Consumer Advocate ("OCA") recommended that no return be allowed for rider recovery at all. The OCA argued that allowing utilities a return on rider-

[11] *Id.* at 21.

related capital spending would weaken a utility's incentive to contain costs and would unduly benefit utility shareholders.

The Iowa Utilities Board ultimately chose a middle ground in establishing a rider rate of return set at the cost of debt. The Board explained its reasoning as follows:

> *There is a reduced risk for the utility if there is a mechanism for recovery of capital infrastructure investment between general rate cases. The utility will be receiving a return on and return of investment prior to the inclusion of that investment in regular rate base. This is money the utility would not otherwise receive. <u>This reduced risk of under recovery should be reflected through a lower return on the investment recovered through the automatic adjustment mechanism.</u> The board has chosen the cost of debt from the utility's last rate case to reflect this reduced risk, rather than to try and establish what the actual reduced risk would be for each utility and each investment, as that process would be time consuming and expensive, thereby undercutting the purpose of the automatic adjustment.*

Applying this reasoning to Xcel's TCR rider would support setting the return at the long-term cost of debt.[12]

d. OAG Recommend Return on Equity

The OAG argued that the Commission has the authority to set a return for the TCR rider that is consistent with the public interest, and it must set a return that will produce just and reasonable rates. In doing so, the Commission must ensure that the return is "commensurate with returns on investments in other enterprises having corresponding risks." If there is any doubt about whether the TCR return is comparable to other investments of similar risk, the Commission must resolve that doubt in favor of ratepayers.

To satisfy these requirements, the OAG recommended that the Commission set the return for Xcel Energy's TCR rider at the Company's cost of long-term debt, which is approximately 4.3 percent. The OAG argued that the risks of Xcel Energy's rider investments are not comparable to the risks of its base rate investments, or the general risk of other utility companies that would make up a traditional proxy group. For these reasons, the risk profile of TCR investments is best compared to the risks of debt securities, and specifically, a reasonable range of debt securities to consider would span from a floor at the cost of two year Treasuries, to a ceiling based on Xcel Energy's cost of long-term debt. Because of the particular circumstances of this proceeding, the OAG stated, it would be reasonable to set the return at the ceiling of that range, based on the Company's cost of long-term debt of 4.3 percent. In reaching this decision, the Commission can follow a path that has already been made by other regulatory Commissions, including the Iowa Utilities Board.

[12] *Id.* at 21-22.

3. Xcel Energy Reply Comments

In its *Reply Comments*, Xcel Energy argued the Company's proposed 10 percent ROE is consistent with ROEs recently authorized for integrated electric utilities in other jurisdictions. Xcel Energy points out that data from SNL Financial shows the average authorized ROE for integrated electric utilities from January 2017 through March 2018 was 9.78 percent and that the Department's recommendation "is lower than the bottom of the range of authorized ROEs in all 50 rate case decisions involving integrated electric utilities in other jurisdictions."[13]

Additionally, Xcel Energy continued its argument that the DCF model understates the return on equity under current market conditions because the dividend yield component of the DCF is being suppressed by the low interest rate environment, which has been characterized by the Federal Energy Regulatory Commission (FERC) as "anomalous". Xcel Energy pointed to recent FERC decisions bolstering its argument that the Commission should not solely rely on the DCF model in determining an appropriate ROE, as the Department does, but rather "consider the results of alternative risk-premium based models, such as the Risk Premium analysis and the CAPM, in order to determine where, within the range of reasonable DCF results, to set the authorized ROE for transmission companies."[14] Xcel Energy also cites decisions from the Pennsylvania Public Utility Commission (PPUC) and the Missouri Public Service Commission citing similar guidance as the FERC.

As for the OAG recommendation of an authorized ROE of 4.30 percent based on Xcel Energy's weighted-average long-term debt, Xcel Energy argued that such a return is not just and reasonable and does not meet the threshold established in the *Hope* and *Bluefield* decisions for a fair return.

Additionally, Xcel Energy argued that the OAG's recommendation does not take into consideration the risks associated with equity ownership, including the risk that dividends are not guaranteed to shareholders. Furthermore, Xcel Energy argued the OAG's recommendation is not consistent with the way in which Xcel Energy finances the transmission projects included in the TCR rider. Specifically, the Company finances TCR investments using a mix of equity and debt and therefore it is not reasonable to set Xcel Energy's authorized ROE for the TCR rider based on long-term debt costs because the Company is using both equity and debt to finance these large transmission projects. The TCR rider's purpose is to allow Xcel Energy to recover the costs (including financing costs) associated with these types of projects before they are placed into service and added to rate base in a future rate case.

As for the decision of the Iowa Utilities Board (IUB) in Docket No. RMU-11-0002, which the OAG claimed supported its use of a long-term debt cost as the equity return for a rider, Xcel Energy noted that the Iowa decision was issued in a 2011 rule making docket for gas distribution utilities, in which the question arose as to the appropriate return for an infrastructure replacement cost rider for gas utilities.

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[13] Xcel Energy *Reply Comments* at Attachment B page 5 of 19.

[14] *Id*. at Attachment B page 7 of 19.

Xcel Energy argued that Minnesota statutes related to the TCR rider provide the necessary precedent for the Commission; and it is not necessary to look to rules for Iowa gas distribution utilities as precedent. As discussed in the *Petition*, the Commission's determination of the appropriate rate of return for the TCR rider looks to the ROE allowed in the Company's last general rate case, unless the Commission determines that a different rate of return is in the public interest.[15] In this instance, the Order establishing the authorized rate of return for Xcel Energy's last general electric rate case was issued on June 12, 2017, when the Company's ROE was set at 9.20 percent as part of a negotiated settlement. In its decision approving the settlement, the Commission stated that "the Settlement does not prevent any party from contesting the ROE when it is applied in rider dockets or other proceedings" and that "parties will be free to assert an alternative ROE at that time."[16] On that basis, Xcel Energy presented an updated cost of equity analysis in support of its recommendation. The OAG's recommended ROE based on long-term debt costs for Xcel Energy is not just and reasonable, and should be disregarded by the Commission.

4. Department Response Comments

The Department provided an updated recommendation based on recent market data and responded to Xcel Energy's reply comments. The Department recommended that the Commission approve an authorized ROE of 8.59 percent. Additionally, the Department continued its recommendation that the ROE established in the instant proceeding be used in all proceedings that require an ROE for the Company's electric operations until Xcel Energy concludes its next rate case, at which time a new authorized ROE would be established.

a. Updated DCF Analysis

As described in *Comments*, the Department developed two proxy groups, one comprised of companies assigned a Standard Industrial Classification (SIC) code of 4911: Electric Services (the Electric Proxy Group, or EPG), and one comprised of companies with a SIC code of 4931: Electric and Other Services Combined SIC (the Combination Proxy Group, or CPG).

The Department updated its proxy group screening analysis and performed constant growth and two-growth DCF analyses on the two updated proxy groups using recent stock prices, dividends, and long-term earnings growth rate forecasts. Table 3 below summarizes the Department's updated constant and two-growth DCF analyses' results for the EPG and CPG.

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[15] Minn. Stat. § 216B.16, subd. 7b (b)(6).

[16] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-15-826, Findings of Fact, Conclusions, and Order at 22 (June 12, 2017).

Table 3: Updated Constant Growth and Two-Growth DCF Analysis Results Includes Flotation Adjustment

Model	Mean Low ROE	Mean ROE	Mean High ROE
Constant Growth DCF Results			
EPG	7.61%	8.21%	8.88%
CPG	8.63%	9.22%	9.82%
Two-Growth DCF Results			
EPG	7.47%	8.09%	8.80%
CPG	8.75%	9.34%	9.94%

b. Updated CAPM Analysis

The Department also updated its CAPM analysis using more recent data to estimate the risk-free rate, the required market return, and beta.

The Department's CAPM estimate of the cost of equity for the EPG, including a 10 basis point adjustment for flotation costs, is 9.71 percent. The Department's CAPM estimate of the cost of equity for the CPG, including a flotation cost adjustment, is 9.59 percent.

Therefore, the Department concluded that its CAPM results when compared with the DCF results for the EPG and CPG proxy groups confirm the reasonableness of its DCF results.

c. Updated Recommended ROE

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, to derive a final ROE recommendation.

Table 4: Department's Updated Recommended ROE

Model	Mean Average Two-Growth DCF ROE Estimate	Weights	Weighted ROE
EPG	8.09%	60.00%	4.85%
CPG	9.34%	40.00%	3.74%
Recommended ROE			8.59%

d. Response to Xcel Energy's Reply Comments

i. Authorized Returns on Equity for other Integrated Electric Utilities

In its *Reply Comments*, the Company noted that the Department's recommended ROE from its Comments was lower than all authorized ROEs authorized in state jurisdictions from January 2017 through March 2018. The Department argued that the Company asserted, without support, that those decisions are relevant. As discussed below, the majority of the authorized ROEs from January 2017 through March 2018 are not relevant to the Commission's determination of a reasonable authorized ROE.

The Department stated that Figure 1 on page 5 of Attachment B of the Company's *Reply Comments* summarizes the ROEs authorized in 34 rate cases for vertically integrated electric utilities from January 2017 to March 2018. Of those 34 rate cases, 23 were resolved via settlements, and 11 were fully-litigated and determined by a state commission. The Department argued that ROEs determined by negotiated settlement agreements may not reflect unbiased assessments of the utilities' cost of equity and therefore cannot reasonably be used as reference points in determining a reasonable ROE for Xcel Energy.

In addition, even for the 11 fully-litigated ROEs, the Department stated that the Company provided no discussion of the factors considered by the state Commissions in determining the ROEs, whether the factors considered align with factors generally considered by the Minnesota Public Utilities Commission, or whether there are any utility-specific factors that do or do not apply to Xcel Energy. For example, one of those 11 is the ROE authorized by the Minnesota Public Utilities Commission for Otter Tail Power Company (Otter Tail) in its most recent rate case. In that case, the Commission considered several factors, including Otter Tail's small size, its history of completing large projects under budget, and its customer satisfaction rankings, that are not relevant to the Xcel Energy. Another of those 11 ROEs is an ROE authorized by Nevada's Public Utilities Commission that includes an ROE incentive for "critical facilities", which is also not relevant to Xcel Energy.

The Department concluded by arguing that, to the extent any of the authorized ROEs are relevant, they reflect other Commission's assessments' of capital market conditions at that time. The Commission has current market data and financial model results based on that data available to it in the record in this Docket and can consider and assess that information directly, rather than indirectly through the assessments of other regulators.

ii. Determinations of other Commissions

Xcel Energy in its *Reply Comments*, reiterated its concern from its *Petition* that current capital market conditions, particularly historically low interest rates, are artificially inflating utility stock prices and causing the DCF model to understate utilities' costs of equity. The Company noted that the FERC and two other state utilities commissions have reached similar conclusions.

In response, the Department reiterated the response it provided in its *Comments*. First, given that the low interest rates that the Company asserts are depressing utility stock prices and

DCF ROE estimates have persisted for several years, it is no longer reasonable to describe them as "anomalous." Second, reasonable investors would not hold an investment if they believed that it is likely to perform poorly. Thus, if investors expected interest rates to rise and utility stock prices to fall as a result, they would sell their stock holdings and bid the price of the stock down until it reaches a point at which the expected return meets investors' required return.

Therefore, Investors' expectations of interest rates are fully embedded in current stock prices, and no additional adjustments, either direct or indirect, intended to reflect investor expectations are necessary.

5. Xcel Energy Reply to Department Response Comments

Xcel Energy continued to recommend an authorized ROE of 10 percent and submitted its own revised analysis in response to the Department's *Response Comments*, shown in Table 5 below.

Table 5: Summary of Xcel Energy ROE Results

	9/30/2017	**1/31/19**
DCF Model – 90-day average stock price		
Constant Growth	8.19%	8.74%
Risk Premium		
30 Yr. U.S. Treasury	10.41%	10.22%
Moody's A-rated Utility Index	10.36%	10.16%
CAPM		
Value Line Beta	10.78%	10.62%
Bloomberg Beta	9.52%	9.35%
Expected Earnings	Not filed	10.79%
Mean of All Methods (not including Expected Earnings)	9.85%	9.82%
Mean of All Methods (including Expected Earnings)	N/A	9.98%

Additionally, Xcel Energy continued to argue that comparison of authorized ROE's from other jurisdictions is appropriate because Xcel Energy competes for capital both within the Company and in the overall investment market. If the Company is placed at the low end of the authorized ROE's, both within Xcel Energy and the market as a whole, investments in Minnesota become a less attractive option. For this reason, Xcel Energy argued that ROE's in other jurisdictions are certainly relevant to this proceeding, as they provide a useful comparison that can assist the Commission it its decision-making process.

Finally, Xcel Energy continued to oppose the Department's recommendation for the Commission to require the ROE established in the instant proceeding be used in all proceedings that require an ROE for the Company's electric operations until Xcel Energy concludes its next rate case, at which time a new authorized ROE would be established.

6. Staff Analysis

In determining the appropriate ROE for a rider docket the Commission has a different statutory directive and starting point than in a general rate case. Staff thinks it is important to start from the directive in the statute applicable to this proceeding which states:

> *allows a return on investment at the level approved in the utility's last general rate case, unless a different return is found to be consistent with the public interest;*[17]

The current ROE was established by Commission Order on June 12, 2017, in the 15-826 Docket. In its *Order* dated June 12, 2017, the Commission approved the Stipulation of Settlement allowing "…Xcel Energy to represent its authorized ROE as nine and two-tenths percent (9.20%) for settlement purposes…"[18] In its *Order* approving the *Settlement*, the Commission made clear that the ROE that Xcel Energy 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.*[19]

Historically, approval of a revised ROE has been confined to Xcel Energy's Gas Utility Infrastructure Cost (GUIC) riders.[20] Primarily, this was due to the length of time that had transpired since the Company's most recent natural gas general rate case (09-1153). The instant *Petition* is the first time that staff is aware that Xcel Energy requested an updated rate of return for an electric rider.[21] The table below lists the Commission approved ROE's in the Company's last natural gas rate case and subsequent GUIC riders.

Table 6: Historical ROE's in Xcel Energy GUIC Riders

Docket No.	Authorized ROE (%)
09-1153 (rate case)	10.09
14-336 (GUIC rider)	10.09[22]
15-808 (GUIC rider)	9.64
16-891 (GUIC rider)	9.04
17-787 (GUIC rider)	TBD

[17] Minn. Stat. § 216B.16, subd. 7b (b)(6).

[18] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-15-826, Findings of Fact, Conclusions, and Order at 10, OP 2 at 68 (June 12, 2017).

[19] *Id.* at 22.

[20] Staff notes that updating the ROE is an issue in the current GUIC proceeding (Docket No. G-002/M-17-787) as well.

[21] Xcel Energy also requested a higher ROE in the Renewable Energy Standards rider filed on November 17, 2017 (Docket No. E-002/M-17-818.

[22] Staff notes that the Commission revised the approved capital structure in this docket.

In the instant docket, both Xcel Energy and the Department provided full ROE analyses discussing areas of capital market conditions, proxy group selection, and cost of equity models. In its analysis, the OAG distinguished between the risk profile discussed in a general rate case and the risk profile of the current docket and argued that a typical rate case ROE analysis should not apply and therefore recommended an ROE factor for the instant *Petition* based on Xcel Energy's long-term cost of debt.

Regarding the cost of equity, all three parties recommended that the Commission follow the standards established in (1) *Bluefield Water Works and Improvement Co. v. Public Service Comm'n*., 262 U. S. 695 (1923) ("*Bluefield*"); and (2) *Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591 (1944) ("*Hope*"). These decisions explain that utility regulators must set rates that permit the utility the opportunity: (1) to attract capital at reasonable terms; (2) to maintain its credit rating and ensure its financial integrity; and (3) to provide a return commensurate with returns on investments having comparable risks.

As discussed above, the Commission approved a settlement which allowed "Xcel Energy to represent its authorized ROE as nine and two-tenths (9.20%) for settlement purposes in this rate case proceeding."[23] However, the settlement also approved a revenue deficiency recommended by the Department whicht is understood by staff to have been calculated using the Department recommended ROE of 9.06 percent.[24] Thus, the most recently approved Xcel Energy electric general rate case contains an ROE which is significantly lower than the ROE put forth by the Company in the instant *Petition*.

Staff also notes, that in its most recent Xcel Energy rider ROE decision, at its meeting on April 25, 2019, involving Xcel Energy's proposed revisions to its Lighting Tariff and LED options, the Commission required the Company to use a 9.06 percent ROE rather than the 9.20 percent in the calculation of the rates in this rider.[25]

The table below lists the various recommended ROE's in the current docket.

Table 7: Recommended ROE's in this TCR docket

	ROE Recommendation (%)
Xcel Energy	10.00
Department - Initial	8.99
Department - Revised	8.59
OAG	4.30[26]

[23] See *Stipulation to Settlement* dated August 16, 2016 at 6.

[24] *Id*. at 5. In addition, Ms. O'Connell from the Department also made a similar statement during the Commission's May 4, 2017 agenda meeting.

[25] In the Matter of Xcel Energy's Petition for Approval of Lighting Tariff Revisions to Include Light Emitting Diode (LED) Options, Docket No. E-002/M-18-729, order pending.

[26] It is staff's understanding that the OAG's recommendation is to establish the rate of return at the Company's long term cost of debt. If so, the actual ROE would need to be calculated based on the Commission's order in this docket. Therefore, staff includes the 4.30 percent as an illustrative figure.

The Commission may also want to consider its ROE decisions in recent electric rate cases in its evaluation of Xcel Energy's request in this proceeding. The table below shows the Commission authorized ROE from the three most recent electric rate cases.

Table 8: Authorized ROE in recent Electric Rate Cases

	Date Filed	Test-Year	Main Order Date	Authorized ROE
Xcel Energy (multiyear rate plan) Docket No. E-002/GR-15-826	Nov. 2, 2015	2016 - 2019	Jun. 12, 2017	9.20%
Otter Tail Power Docket No. E-017/GR-15-1033	Feb. 16, 2016	2016	May 1, 2017	9.41%
Minnesota Power Docket No. E-015/GR-16-664	Nov. 2, 2016	2017	Mar. 12, 2018	9.25%

The only ROE decision the Commission has to make at this meeting is the decision about Xcel Energy's ROE for the TCR rider. Both the Company and Department agreed to use the ROE established for the TCR rider as the ROE to be used for the RES rider which is also scheduled for the May 23rd agenda meeting. Xcel Energy's GUIC rider involves its gas utility and will be determined separately.

In addition, the Commission may wish to consider how it will handle future rider ROE requests as they are becoming more common and consume a considerable amount of time. One option is the establishment of a minimum time period that must pass from the conclusion of a general rate case before the utility is able to request a different ROE in a rider proceeding. Staff notes that Xcel Energy requested an updated ROE in the instant *Petition* less than five months after issuance of the final Order in the 15-826 Docket.[27] Staff believes that there must be a clear and convincing rationale for the Commission to deviate from the authorized ROE established in the most recent rate case especially in this proceeding where less than five months had elapsed.

Staff concludes that a minimum period of three years from the final order in its most recent rate case is an appropriate amount of time. This would strike the appropriate balance between the utility being able to meet its financial needs and the efficient use of regulatory resources.

In the alternative, the Commission could request Xcel Energy discuss the establishment of a minimum time period in its upcoming rate case. This will allow for a full discussion of the merits of the proposal and development of a complete record.

The Commission may wish to query the parties regarding staff's proposal at its May 23, 2019, agenda meeting.

[27] Xcel Energy also requested a higher ROE in the Renewable Energy Standards rider filed on November 17, 2017 (Docket No. E-002/M-17-818).

7. Decision Alternatives

1. Approve Xcel Energy's proposed return on equity of 10.00 percent. [Xcel Energy]

2. Approve the Department's proposed return on equity of 8.99 percent [Department initial position]

3. Approve the Department's proposed return on equity of 8.59 percent. [Department revised position]

4. Approve the OAG's proposed return on equity of 4.30 percent. [OAG]

5. Determine that no party has convinced the Commission to alter the currently authorized rate of return established in Xcel Energy's most recent electric rate case (Docket No. E-002/GR-15-826).

    a. 9.20 percent (as represented to the investment community)
    b. 9.06 percent (used to calculate revenue requirement and set rates)

    Staff note: the three following alternatives would be in addition to any of the alternatives shown above.

6. Adopt the Department's recommendation requiring Xcel Energy to use of the ROE determined in the present docket in all electric 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. [Department]

    and/or

7. Establish a policy requiring a minimum period of three years from the date of the final Order in Xcel Energy's most recent electric rate case before the Company may request a revision to the rate of return in a future TCR rider. [Staff]

    and/or

8. Require Xcel Energy to address the issue of establishing a policy requiring a minimum period of time to pass from the final order of its most recent rate case before the Company is allowed to request revision to its established rate of return in any subsequent rider petition. [Staff]

2. Accumulated Deferred Income Taxes (ADIT) Treatment

a. Background

For financial accounting and ratemaking purposes, public utilities depreciate assets using straight-line depreciation. Under straight-line depreciation, an asset's value decreases by an equal amount each year of its useful life.

For federal tax purposes, however, most utilities depreciate assets using accelerated depreciation. Under accelerated depreciation, an asset loses value more quickly during its early years, allowing for greater deductions and lower income taxes in these years.

The difference between the tax a utility pays under accelerated depreciation and the tax that it would have paid under straight-line depreciation is known as accumulated deferred income tax (ADIT). ADIT represents the prepayment of a utility's income taxes by its ratepayers, and many regulatory agencies, including this Commission, require utilities to deduct ADIT from the rate base which reduces the revenue requirement.

Internal Revenue Service (IRS) rules specify how utilities are to calculate the amount of the ADIT rate-base offset. In particular, when a utility uses a "future period" to determine the amount of federal income tax to include in rates, the IRS requires that the utility prorate projected ADIT accruals.[28]

ADIT proration has proven to be controversial in the context of riders. Most riders, including Xcel Energy's TCR rider, are implemented through a rate adjustment that is calculated using forecasted costs. The IRS has expressed in private letter rulings (PLR) its view that, to the extent that a rate is based on forecasted costs, it reflects a "future period," and the associated ADIT accruals must be prorated.[29]

However, another feature of most riders is that any over- or under-recovery relative to actual costs is trued up at the end of the year. In the instant petition, Xcel Energy and the Department disagree whether ADIT proration is necessary for the TCR true-up.

b. Xcel Energy

In its *Petition*, the Company forecasted ADIT balances for October through December 2017. In its second supplemental response to Department IR No. 3,[30] the Company provided actual ADIT balances for 2017, eliminating the need for proration of 2017 ADIT balances.

In *Reply Comments*, Xcel Energy cited an Otter Tail Power Company (Otter Tail) regulatory filing in South Dakota dated January 29, 2018, in which Otter Tail asserted that they are required to

[28] 26 C.F.R. § 1.167(l)-1(h)(6)(ii).

[29] A PLR is a statement issued by the IRS at the request of a taxpayer that interprets and applies tax laws to the taxpayer's represented set of facts. With limited exceptions, a PLR may not be relied on as precedent by other taxpayers. *See* 26 U.S.C. § 6110(k)(3).

[30] Department *Comments* Attachment 6.

prorate ADIT in order to comply with IRS regulations and avoid a tax normalization violation.[31] Xcel Energy argued that they see no way to avoid "the requirement that tax normalization is required to use accelerated depreciation, and Treasury Regulation §1.167(I)(h)(6) requires a proration of forecasted ADIT to comply."[32]

Xcel Energy also provided the following alternative method as a way to mitigate the rate impact of ADIT proration:

> The Company has reviewed recently-released IRS guidance and engaged Deloitte Tax Services to evaluate our rider calculations and propose further optimizations that could be applied to reduce or effectively eliminate the impact to customers. Through this process we identified a possible modification, which is to treat each forecast month as a test period since the revenue requirements in these riders are calculated monthly. This allows the monthly ADIT balance to be reset to its un- prorated beginning balance and only the monthly activity receives the proration. This treatment reduces the impact to the ratepayers in these rider mechanisms significantly. This treatment will require the ADIT prorate to be embedded in the rate base calculation rather than separated as a line item.[33]

On May 25, 2018, Xcel Energy submitted its first supplement to its reply comments. The Company states that Deloitte, along with Xcel's tax experts identified the following 3 possible modifications to Xcel's process for handling ADIT proration:

1) Treat each forecast month as a test period using the revenue requirements in these riders which are calculated monthly. This allows the monthly ADIT balance to be reset to its un-prorated beginning balance and only the monthly activity receives the proration.

2) Then apply a mid-month convention for the proration factors in each month.

3) Remove ADIT from the beginning-of-month and end-of-month rate base average, since the proration is itself a form of averaging.

On July 16, 2018, the Company filed its *Second Supplement* to its reply comments providing a more granular breakdown of its modified ADIT proration methodology, as requested by the Department. Additionally, the Company reaffirmed its position that the overall impact on customers is de minimis; the difference between Xcel Energy and the Department's proposals is approximately $238 in overall revenue requirement impact.

Finally, Xcel Energy continues to request the Commission allow it to use its new ADIT proration methodology, as noted in Deloitte's recommendations, for the currently pending rate filings,

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31 Xcel Energy *Reply Comments* at 7.

32 *Id*. at 8.

33 *Id*.

with no commitment regarding future treatment. The Company will refrain from treating this outcome as an argument for acceptance in future proceedings.

c. Department

The Department recommends that the Commission require Xcel Energy 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 RES Rider filings. Alternatively, the Commission could require Xcel Energy's RES Rider to be based solely on historical costs by implementing recovery of rates one day after the rate recovery period. In this case, the RES Adjustment Factor would be implemented January 1, 2019.

In *Response Comments* the Department continues to disagree with Xcel Energy and other utilities' proposals to maintain proration in true-up calculations. [**Staff note:** In these response comments, the Department copied its reply comments from Xcel Energy's State Energy Policy (SEP) Rider. in Docket No. G-002/M-18-184. Not all of the copied language applies to the instant proceeding so for the sake of brevity and clarity certain passages are not included in these briefing papers but the entire discussion can be found on pages 13 – 15 of the Department's Response Comments in this docket.]

The Department's arguments are as follows:

> Second, Xcel's proposed monthly method is needlessly complex, difficult to monitor, and would still violate the requirement that "Xcel Gas shall not prorate its accumulated deferred income taxes in the SEP rider." By contrast, as discussed below, the Internal Revenue Service (IRS) has already provided a simple and reasonable means by which the rider can go forward without ADIT proration. Again, while the Department appreciates that Xcel tried to minimize the effects of ADIT proration on ratepayers, the significant and needless degree of complexity in Xcel's new method would require excessive resources to implement and monitor, year after year.
>
> Third, Xcel's statement that "the Company has no particular interest in the provision other than it is required in order to preserve the significant deferred tax benefits for our customers" is not accurate, for two reasons. First, the Company clearly stands to financially benefit from charging higher rates to its ratepayers when ADIT is prorated. Second, the Company is not required to prorate ADIT to preserve tax benefits. Xcel ignores the fact that the IRS, which Xcel Gas appropriately cites as the authority requiring ADIT proration to preserve normalization, has been abundantly and repeatedly clear that "if rates go into effect after the end of the test period, the opportunity to flow through the benefits of future accelerated depreciation to current ratepayers is gone, and so too is the need to apply the proration formula." Thus, Xcel Gas is not required to prorate ADIT when the rider is implemented after the test period.
>
> Fourth, the Company's statement that "without changing the law or

regulation, the Company sees no way to avoid this circumstance" is at odds with the fact that, as noted above, the IRS has already provided a means by which Xcel Gas can charge higher rates to its ratepayers through a rider, without violating any IRS requirements. Implementing the rider after the test period allows the Company and its customers to benefit; the Company benefits from the extraordinary ratemaking treatment of a rider rather than a rate case whereas the Company's ratepayers are given the full credit they deserve from the reduction in rate base from ADIT without any of the issues caused by proration.

Sixth, as also noted above, Xcel Gas's concern about a minor delay in recovery of costs ignores the fact that recovery of costs through riders is extraordinary ratemaking as it would allow recovery of costs that would normally be recovered during a rate case, only after the utility demonstrates that the facilities are used and useful and all costs are prudently incurred. Thus even using historical data would result in recovery earlier than would regularly be expected.

Seventh, Xcel Gas also ignores the small benefit that its ratepayers receive as a result of this minor (one-year or less) delay, compared to the ordinary, reasonable process whereby utilities are responsible for costs until the facilities are in place used and useful, and shown to be reasonably incurred. As the National Regulatory Research Institute explained in its October 2009 webinar and report, "The Two Sides of Cost Trackers: Why Regulators Must Consider Both," Ken Costello pointed out that riders "weaken the incentive of a utility to control its costs". This report stated the following benefits of the lag:

> Economic theory predicts that the longer the regulatory lag, the more incentive a utility has to control its costs; when a utility incurs costs, the longer it has to wait to recover those costs, the lower its earnings are in the interim. The utility, consequently, would have an incentive to minimize costs.

Based on the above, the Department concludes that the IRS' solution of waiting until the end of the test period to implement rates is a reasonable, straight forward and accurate fix for these problems and eliminates the need to prorate ADIT.

Therefore, the Department recommends that the Commission require Xcel Energy's RES Rider to be based solely on historical costs by implementing the RES Adjustment Factor one day after the period in which the costs were incurred (January 1, 2019), thereby eliminating the need to prorate ADIT.

d. Staff Analysis

This issue of proration of ADIT was first discussed in depth in Xcel Energy's Transmission Cost Recovery Rider in Docket No. E-002/M-15-891 at the Commission's December 8, 2016, agenda meeting.

Since that time the issue of ADIT proration has been a disputed issue in many other dockets with differing results. The table below provides a list of dockets with Commission decisions.

Table 9: ADIT Proceedings

Company	***Docket No.***	***Proceeding***	***Outcome***
Xcel Energy	G-002/M-18-692	Gas Utility Infrastructure Charge (GUIC)	Ongoing
Minnesota Power	E-015/M-18-375	Renewable Resource Rider (RRR)	Allowed proration due to de minimis amount ($299) – Order issued 11/19/2018
Great Plains Natural Gas Co.	G-004/M-18-282	Gas Utility Infrastructure Charge (GUIC)	Allowed proration – Order issued 02/12/2019
Minnesota Energy Resources Corp.	G-011/M-18-281	Gas Utility Infrastructure Charge (GUIC)	Allowed the use of forecasted expenses – Order issued 02/05/2019
Xcel Energy	G-002/M-18-184	State Energy Policy (SEP) Rider	Denied request for forecasted period – Order issued December 21, 2018
Xcel Energy	E-002/M-17-797	Transmission Cost Recovery (TCR) Rider	Ongoing (Current Docket)
Xcel Energy	G-002/M-17-787	Gas Utility Infrastructure Charge (GUIC)	Ongoing
Xcel Energy	G-002/M-16-891	Gas Utility Infrastructure Charge (GUIC)	Denied proration – Order issued 2/8/2018
Minnesota Power	E-015/GR-16-664	General Rate Case	Final Order issued after test year. Proration required for interim rates. Order issued 3/12/2018

Company	***Docket No.***	***Proceeding***	***Outcome***
Otter Tail Power	E-017/GR-15-1033	General Rate Case	Final Order issued after test year. Proration required for interim rates. Order issued 5/1/2017
Xcel Energy	E-002/M-15-891	Transmission Cost Recovery (TCR) Rider	Commission Order issued after test year
Xcel Energy	E-002/M-15-805	Renewable Energy Standard (RES) Rider	Issue deferred to current petition.

On June 21, 2018, FERC instituted proceedings to examine the methodology for public utilities to calculate ADIT balances in their projected test years and annual true-up calculations for transmission formula rates.

In the background section of its June 21, 2018 Order,[34] FERC stated the following:

> "Under Commission ratemaking policies, income taxes included in rates are determined based on the return on net rate base that is calculated using straight- line depreciation. However, in calculating the actual amount of income taxes due to the Internal Revenue Service (IRS), companies generally are able to take advantage of accelerated depreciation. Accelerated depreciation will usually lower income taxes payable by companies during the early years of an asset's life followed by corresponding increases in income taxes payable during the later years of an asset's life when the depreciation is lower. This means that a company's income taxes owed to the IRS during a period will differ from its income tax expenses used for Commission ratemaking purposes during the same period. The difference between the income taxes received by a company in its rate based on straight-line depreciation and the actual income taxes owed to the IRS by the company are reflected in an ADIT account. Because the resulting balance in an ADIT account effectively provides the company with cost-free capital, the Commission generally requires a company to subtract the ADIT from rate base, thereby reducing customer charges. The reduction to rate base is diminished as the ADIT reverses due to actual taxes owed to the IRS subsequently exceeding the income taxes calculated based on straight-line depreciation***. This method***

[34] June 21, 2018, 163 FERC 61,200; ORDER INSTITUTING SECTION 206 PROCEEDINGS, COMMENCING PAPER HEARING PROCEDURES, AND ESTABLISHING REFUND EFFECTIVE DATE.

> ***of passing the time value of benefits from accelerated depreciation on to ratepayers throughout the asset's life is referred to as tax normalization."***[35] (emphasis added.)
>
> "The depreciation normalization rules of the Internal Revenue Code and the IRS regulations (Normalization Rules) mandate the use of a very specific proration procedure in measuring the amount of ***future test period ADIT*** that can reduce rate base. Section 1.167(l)-1(h)(6)(ii) of the IRS regulations requires that, ***if a utility uses solely a future period (projected test year) to determine depreciation, 'the amount of the reserve account for the period is the amount of the reserve at the beginning of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during such period.'*** The pro rata amount of any increase during the future portion of the period is determined by multiplying the increase by a fraction, the numerator of which is the number of days remaining in the period at the time the increase is to accrue, and the denominator of which is the total number of days in the future portion of the period."[36] (emphasis added.)

The timing of test periods is critical in determining the need for normalization through proration adjustments. Because the test period has already ended (December 31, 2018), if the Commission authorizes Xcel Energy to prorate ADIT using either one of its methodologies, the Company will collect the extra revenue requirements despite the fact that the test period has concluded. Ordering Xcel Energy to use the Department's methodology (i.e. a historical test period) resolves the issue of ADIT proration in this docket, but the Commission may wish to clarify which methodology shall be used in future GUIC filings so that this issue does not continue to be disputed.

Xcel Energy Reply Comments Filed in Docket E-002/M-17-797

In the TCR Docket, Xcel Energy filed additional comments on April 11, 2019.

> *…the 2018 test period for this TCR Rider proceeding has ended. The Company agrees that this means rates implemented after January 1, 2019 do not need to include proration of forecasted ADIT balances. As such, the Company will update the TCR tracker to remove ADIT proration for the 2018 test period and provide updated schedules as part of a compliance filing in this docket. We do not believe that any decision regarding ADIT proration is necessary in this proceeding.*

Xcel Energy did not file similar comments in the current petition. However, the forecast period for this docket has also passed. The Commission may wish to ask the Company at its meeting on May 23rd to explain its current position on ADIT proration in this docket, and, whether it mirrors that of 17-797. Staff notes that the Company's comments in the TCR docket do not

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[35] *Id*. at 2-3.

[36] *Id*.

indicate a generalized new position regarding the issue of ADIT proration; the Company is merely stating that ADIT proration is a nonissue in that particular docket. The Commission may wish to still address ADIT proration on a going-forward basis in this and other rider dockets.

e. Decision Alternatives

9. Allow Xcel Energy to implement its RES rider factor effective January 1, 2019, and authorize the Company to recover its ADIT proration as proposed.

10. Allow Xcel Energy to implement its RES rider factor effective January 1, 2019, and authorize the Company to recover its ADIT proration, calculated by Deloitte Tax Service as proposed in *Supplemental Reply Comments*.

11. Require Xcel Energy to implement its RES rider effective January 1, 2019, thereby eliminating the need to prorate ADIT. (Department)

    Staff note: the following alternative would be in addition to any of the ADIT alternatives shown above.

12. Require Xcel Energy to utilize the ADIT proration methodology ordered by the Commission in this docket to be used in all future RES rider filings. (Staff)

B. Resolved Issues

1. North Dakota Income Tax Credits

On April 11, 2017, the Commission issued an *Order* requiring Xcel Energy to credit its Minnesota ratepayers for their proportionate share of used North Dakota Investment Tax Credits (NDITC) associated with the Courtenay Wind Project, based on the pro-rata share of the costs of the Courtenay Wind Project that is charged to Minnesota ratepayers;[37]

However, in its *Petition*, Xcel Energy stated that the NDITCs associated with the Courtenay Wind project remained $0 for the 2017-2018 period for which the Company is requesting recovery.[38] In response to a Department information request,[39] Xcel Energy further explained that:

> Although the Courtenay Wind project qualifies for the NDITC, the credit is limited by the Company's North Dakota taxable income. Since Xcel Energy is

[37] *In the Matter of the Petition of Northern States Power Company for Approval of the Renewable Energy Standard (RES) Rider True-up Report for 2015, Revenue Requirements for 2016, and a Revised Adjustment Factor*, Docket No. E-002/M-15-805, ORDER APPROVING RECOVERY OF ACTUAL 2016 COSTS – INCLUDING COURTENAY WIND COSTS AND OFFSETTING TAX CREDITS – AND 2015 TRUE-UP at 8 (April 11, 2017).

[38] Xcel Energy *Petition* at 9.

[39] Department *Comments* at Attachment 8.

> not forecasting to use any NDITC associated with the Courtenay Wind project in 2017 and 2018, the Company did not credit Minnesota Ratepayers for any NDITC in the 2017 and 2018 RES Rider revenue requirements.

The Department concluded that this is consistent with the timing of tax credits. Before the NDITCs for the Courtenay Wind project (and other wind projects in North Dakota) are awarded, PTCs generated by the Courtenay Wind project (and other wind projects in North Dakota) must be used first. Since the 2017 Revenue Requirement request is a net refund to ratepayers, in part due to the large amount of PTCs generated by the Courtenay Wind project, the Company's North Dakota taxable income remains low enough such that they are not awarded any NDITCs, though they remain eligible.

The Department recommended that the Commission continue to maintain this requirement that Xcel Energy credit its Minnesota ratepayers for their proportionate share of used North Dakota Investment Tax Credits (NDITC) associated with the Courtenay Wind Project, based on the pro-rata share of the costs of the Courtenay Wind Project that is charged to Minnesota ratepayers.

2. Capital Cost Components for Wind Portfolio Projects

In its *Comments* the Department asked Xcel Energy to provide an explanation of the various line-item components of the CWIP expenditures for the four self-build wind projects.[40]

In *Reply Comments*, Xcel Energy provided an explanation of the five line-item components, which reference separate work order numbers and delineate the various project cost components.[41] Each of these components appear to be related to various components of each of the wind projects; therefore, the Department concluded that it is reasonable to include them in each project's capital costs.

3. Return on CWIP Component for the Courtenay Wind Farm

The Courtenay Wind Project was approved in Docket No. E-002/M-15-401, and the Commission capped the project costs at $300 million, plus the associated Allowance for Funds Used During Construction (AFUDC).[42] Since Minnesota Statute §216B.1645, subd. 2a (2) allows for a return on CWIP in lieu of AFUDC, Xcel Energy calculated the RES Rider revenue requirements for the Courtenay Wind Project including a return on CWIP in lieu of AFUDC.

In *Comments*, the Department asked Xcel Energy to provide supporting documentation showing the return-on-CWIP cost components of the total project costs for the Courtenay

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[40] Department *Comments* at 13.

[41] Xcel Energy *Reply Comments* at 2-3.

[42] *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of the Acquisition of the 200 MW Courtenay Wind Farm*, Docket No. E-002/M-15-401, ORDER APPROVING ACQUISITION UNDER MINN. STAT. § 216B.1645, SUBD. 2a AND AUTHORIZING COST RECOVERY, at 4 (September 2, 2015).

Wind Project.[43] The Company provided an explanation of the difference between the Courtenay Wind Project's total costs when calculated under the two different methodologies (AFUDC vs. return-on-CWIP).[44] In *Response Comments*, the Department determined that due to the differences in how each is calculated, the return-on-CWIP method results in $1.8 million higher project costs. However, as the total project cost amounts for each methodology comply with the Commission's ($300 million plus AFUDC) cost cap, the Courtenay Wind Project's total project cost of $297.2 million is eligible for inclusion in the 2017 and 2018 RES Rider Revenue requirements.

4. Data Discrepancy Related to CWIP Expenditures for the Wind Portfolio Projects

In *Comments*, the Department noted a difference between Attachments F and G's calculation of the CWIP Expenditures and asked Xcel Energy to explain the discrepancies found in the CWIP Expenditures of each of the wind projects (the four self-build projects, the two build-own-transfer (BOT) projects, and the Courtenay Wind Project).[45] In *Reply Comments*, Xcel Energy pointed out that Attachment F's calculation of CWIP Expenditures is an annual total, whereas Attachment G's calculation of CWIP Expenditures is a cumulative total.[46]

This issue is relevant in the calculation of each project's revenue requirements: Attachment G calculates each project's revenue requirements based on the cumulative total of the CWIP Expenditures. As the revenue requirements reflect the annual recovery of each project's CWIP Expenditures over the life of the project, using the cumulative total is the appropriate figure to be used in determining the Revenue Requirement and, ultimately, setting the RES Adjustment Factor.

Thus, the Department concluded that the 2018 CWIP Expenditures for the Wind Portfolio and the Courtenay Wind projects used the correct CWIP expenditure data, and therefore, Xcel Energy accurately calculated the capital cost component of the 2018 revenue requirements for the Wind Portfolio and Courtenay Wind projects.

5. Data Discrepancy in the RES PTC Tracker Component of the Revenue Requirement Calculation

In *Comments*, the Department asked Xcel Energy to explain a $1,655 discrepancy in the 2018 RES PTC Tracker component of the revenue requirement calculation found in Attachments B and D and the 2018 RES PTC Tracker component calculation found in Attachment H, all of which are attachments to Xcel Energy's second supplemental response to DOC IR No. 3.[47] During its review, the Company also discovered another discrepancy of approximately $512,880 for the 2017 RES PTC Tracker components found in Attachments B

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[43] Department *Comments* at 11.

[44] Xcel Energy *Reply Comments* at 3.

[45] Department *Comments* at 14-15.

[46] Xcel Energy *Reply Comments* at 4.

[47] Department *Comments* at 24.

and C of Xcel Energy's second supplemental response to DOC IR No. 3.[48] The Department noted that a $1,481 discrepancy also exists for the 2019 RES PTC Tracker component found in Attachment E of Xcel Energy's second supplemental response to DOC IR No. 3.

Xcel Energy explained in *Reply Comments*, that the 2018 and 2019 discrepancies are a result of a rounding difference between Attachments B, D, and E, and Attachment H. In Attachments B, D and E, the Company rounded the tax gross-up value to the fourth digit, but rounded to the fifth digit on Attachment H. This resulted in a minor difference of $1,655 for 2018 and $1,481 for 2019. Xcel Energy indicated that they should have used the Attachment H figure, as it is the more accurate figure. The Department does not oppose use of the more accurate Attachment H figure.

As noted above, Xcel Energy also indicated that there is a discrepancy between 2017 RES PTC Tracker component found in Attachments B and C, and Attachment H.[49] The cause for this discrepancy is the result of a change in the Interchange Energy allocator, which was reduced from 84.01% in the in the original petition's forecast to the 83.55% resulting from the Tax Reform Update. The change decreased the PTC credit from ($11,463,017) to ($10,950,138), or$512,880.

The Department sought additional clarification on the derivation of the various jurisdictional allocators used in the calculation of the 2017 PTC Tracker component. Xcel Energy explained which allocators influenced the 2017 RES PTC Tracker amount, what the allocators' purposes are, which regulatory proceedings they are derived from, and how updates to them in their respective regulatory proceedings ultimately resulted in the $512,880 increase.[50]

Xcel explained that two jurisdictional allocators are relevant in the derivation of the "PTC Jurisdictional Allocator": the "NSPM Interchange Energy (Interchange Electric)" allocator and the "MN 12-month CP Energy (Electric Energy)" allocator.[51] Xcel explained that multiplying these two allocators together results in the "PTC Jurisdictional Allocator," which was ultimately used to calculate the 2017 RES PTC Tracker component

Based on Xcel Energy's explanations, the Department concluded that the $512,880 increase is reasonable.

6. REC Sales Transactions

In *Comments*, the Department asked Xcel Energy to provide further support and justification, including who bore the cost, for four REC sales transactions where 100% of the proceeds were not allocated to the Minnesota jurisdiction.[52]

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[48] Xcel Energy *Reply Comments* at 4.

[49] *Id*.

[50] Department *Response Comments*, Attachments 13-15.

[51] Department *Response Comments*, Attachment 14.

[52] Department *Comments* at 21.

Xcel Energy responded in *Reply Comments* with an expanded explanation of their allocation method of REC sale transactions. The Company asserted that, with few exceptions, the "costs for the resources on the NSP System that generate RECs are paid for by all of the NSP jurisdictions…". Xcel Energy also explained that they "assign NSP-system RECs to each jurisdiction as they are generated, based on load share ratios" and further, "subsequent sales transaction proceeds…are based on which jurisdiction's RECs were sold, not an allocator."[53]

Xcel Energy also provided information showing the number of Minnesota RECs and non-Minnesota RECs that were utilized for each of the REC sale transactions included in the RES Rider.[54] According to the Company, approximately 90% of RECs sold were RECs from the Minnesota jurisdiction, and as a result, 90% of the proceeds were assigned to the Minnesota jurisdiction. The Department found that Xcel Energy provided a clear explanation of how the Company derived Minnesota's jurisdictional allocation of REC sales revenue.

Based on the explanation discussed above, the Department concluded that the $10.552 million credit to Xcel Energy's ratepayers in the 2017 RES Rider revenue requirement is reasonable.

7. RES Adjustment Factors

a. Calculation of Adjustment Factors

Xcel Energy originally indicated that the 2017 RES Adjustment Factor would result in an average one-time refund of $4.40 and the 2018 RES Adjustment Factor would result in an average bill impact of $0.36 per month for the remainder of 2018, each in terms of the impact on a typical residential customer using 675 kWh per month.

However, in response to the Department's information requests and in supplemental information provided by the Company, various changes have been made to Xcel Energy's revenue requirement requests for 2017 and 2018. The one-time 2017 refund and the 2018 on-going RES Adjustment Factors have changed accordingly. According to the Department's analysis, the 2017 RES Adjustment Factor would result in an average one-time refund of $5.71 and the 2018 RES Adjustment Factor would result in an average bill impact of $0.82 for the remainder of 2018, each in terms of the impact on a typical residential customer using 675 kWh per month.

The Department reviewed the Company's calculations and concluded that they are consistent with previous Commission RES Orders.[55]

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[53] Xcel Energy *Reply Comments* at 5.

[54] *Id.*, at 6.

[55] Docket Nos. E-002/M-14-733 and E-002/M-15-805.

b. Timing of Adjustment Factors

On page 20 of the *Petition*, the Company stated the following:

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

The Department noted that riders have subsequent true-up periods and as such the tracker balance will show what Xcel Energy will have collected in revenues. Any difference between the total 2017 and 2018 revenue requirements and the amount of revenues received from customers under this rider will be captured in the tracker balance going forward for the next true-up and RES Rider filing. Further, the 2018 revenue requirements are projected, and will also be trued- up to actuals in the next RES Rider filing. Therefore, the Department recommends that the Company implement the proposed 2017 RES Rider Adjustment Factor in the beginning of the month following the Commission's Order in this instant proceeding, and to subsequently implement the 2018 RES Rider Adjustment Factor in the beginning of the month following the implementation of the 2017 RES Rider Adjustment Factor.

c. Rate Smoothing

On page 20 of the Petition, the Company explained its proposal to implement two separate Adjustment Factor rates:

> First, the one-time credit will allow a more timely refund to the customers who were charged the RES Rider rate in 2017. If the refund is done in one billing period the refund should more closely match to the 2017 customers charged the RES Rider rate. If the credit is spread out over a longer period of time, there is greater mismatch in the customer population, and customers will wait longer to receive the credit.
>
> Second, implementing the second on-going rate serves as a rate smoothing mechanism. Beginning in 2019, as the Wind Portfolio project construction begins in earnest and project in-servicing begins, the RES Rider revenue requirements are forecasted to increase.[20] We predict that this will still be the case even with some amount of not-yet-known additional PTC and REC sales off-sets. We propose this approach to smooth the changes in rates between 2017 and 2019 by issuing the credit for 2017 to restore balance to the tracker and then implementing a 2018 rate. The step between the 2018 rate and the future 2019 rate will be smoothed.

In information requests, the Department asked the Company to "calculate the impact on the RES Rider Adjustment Factor if the proposed refund is amortized over 2018 instead of provided to ratepayers in the form of a one-time refund in February 2018" and, further, to "explain the Company's position on whether this would help smooth rate changes between the 2018 rate and the future 2019 rate."

Xcel Energy provided the following responses:

1. The Company provides Attachment 1 to this response to show the impact of netting the proposed 2017 refund with the 2018 revenue requirements and adjusting the rate over February-December of 2018. This produces a RES Rate Factor of negative 0.038%.

2. The Company does not believe this will help smooth rate changes between the 2018 and the future 2019 rate. The currently forecasted revenue requirements are $43.5 million compared to $10.5 million for 2018.

3. Amortizing the refund over 2018 creates an artificially low rate which then would spike to a RES Rate Factor of 1.920% [in 2019].

   Additionally, if the 2019 petition is not heard and implemented by January 1, 2019, the artificially low 2018 rate could exacerbate the eventual rate factor increase for 2019 recovery as the Company would have a large carryover balance in addition to the new revenue requirements.

The Department reviewed the calculations provided by Xcel Energy and concludes that amortizing the proposed refund over 2018 would not result in a smoother rate than the Company's proposed rate implementation. The Department recommends that the Commission approve the proposed rate implementation method provided by the Company.

V. Decision Alternatives

Disputed Issues

Return on Equity

1. Approve Xcel Energy's proposed return on equity of 10.00 percent. [Xcel Energy]

2. Approve the Department's proposed return on equity of 8.99 percent [Department initial position]

3. Approve the Department's proposed return on equity of 8.59 percent. [Department revised position]

4. Approve the OAG's proposed return of 4.30 percent. [OAG]

5. Determine that no party has convinced the Commission to alter the currently authorized rate of return established in Xcel Energy's most recent electric rate case (Docket No. E-002/GR-15-826).

   a. 9.20 percent (as represented to the investment community)
   b. 9.06 percent (used to calculate revenue requirement and set rates)

   Staff note: the three following alternatives would be in addition to any of the alternatives shown above.

6. Adopt the Department's recommendation requiring Xcel Energy to use of the ROE determined in the present 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. [Department]

   and/or

7. Establish a policy requiring a minimum period of three years from the date of the final Order in Xcel Energy's most recent electric rate case before the Company may request a revision to the rate of return in a future TCR rider. [Staff]

   and/or

8. Require Xcel Energy to address the issue of establishing a policy requiring a minimum period of time to pass from the final order of its most recent rate case before the Company is allowed to request revision to its established rate of return in any subsequent rider petition. [Staff]

ADIT Proration

9. Allow Xcel Energy to implement its RES rider factor effective January 1, 2019, and authorize the Company to recover its ADIT proration as proposed.

10. Allow Xcel Energy to implement its RES rider factor effective January 1, 2019, and authorize the Company to recover its ADIT proration, calculated by Deloitte Tax Service as proposed in *Supplemental Reply Comments*.

11. Require Xcel Energy to implement its RES rider effective January 1, 2019, thereby eliminating the need to prorate ADIT. (Department)

    Staff note: the following alternative would be in addition to any of the ADIT alternatives shown above.

12. Require Xcel Energy to utilize the ADIT proration methodology ordered by the Commission in this docket to be used in all future RES rider filings. (Staff)

Resolved Issues

North Dakota Income Tax Credits

13. Continue to require Xcel Energy to credit its Minnesota ratepayers for their proportionate share of used North Dakota Investment Tax Credits (NDITC) associated with the Courtenay Wind Project, based on the pro-rata share of the costs of the Courtenay Wind Project that is charged to Minnesota ratepayers.

Capital Cost Components for Wind Portfolio Projects

14. Approve the capital cost components of the 2017 and 2018 revenue requirements for the four self-build projects.

Return on CWIP Component for the Courtenay Wind Farm

15. Approve the Courtenay Wind Projects costs for inclusion in the 2017 and 2018 revenue requirements.

Data Discrepancy Related to CWIP Expenditures for the Wind Portfolio Projects

16. Approve the 2018 CWIP expenditures for the Wind Portfolio and the Courtenay Wind projects.

RES PTC Tracker Data Discrepancy

17. Approve the revised 2017 RES PTC Tracker amount of ($10,950,138).

REC Sales Transactions

18. Approve a credit to the 2017 RES PTC Tracker in the amount of $10.552 million.

RES Adjustment Factors

19. Require Xcel Energy to implement the 2017 RES Rider Adjustment Factor at the beginning of the month following the Commission's Order in the instant proceeding, and to subsequently require the Company to implement the 2018 RES Rider Adjustment Factor at the beginning of the month following the implementation of the 2017 RES Rider Adjustment Factor.

Rate Smoothing

20. Approve Xcel Energy's proposed Rate Smoothing method.

Compliance Filing

21. Require Xcel Energy to submit a compliance filing within 10 days of the date of the final order in this docket. The compliance filing shall contain:

- Commission approved ROE and its impact on this proceeding;
- Updated tariff pages to reflect the 2017 and 2018 RES Rider Adjustment Factors approved by the Commission;
- Updated Revenue Requirement based on Commission approved recommendations.

Minn. Stat. § 216B.1645, Subd. 2a. Cost recovery for utility's renewable facilities.

(a) A utility may petition the commission to approve a rate schedule that provides for the automatic adjustment of charges to recover prudently incurred investments, expenses, or costs associated with facilities constructed, owned, or operated by a utility to satisfy the requirements of section 216B.1691, provided those facilities were previously approved by the commission under section 216B.2422 or 216B.243, or were determined by the commission to be reasonable and prudent under section 216B.243, subdivision 9. For facilities not subject to review by the commission under section216B.2422 or 216B.243, a utility shall petition the commission for eligibility for cost recovery under this section prior to requesting cost recovery for the facility. The commission may approve, or approve as modified, a rate schedule that:

(1) allows a utility to recover directly from customers on a timely basis the costs of qualifying renewable energy projects, including:

(i) return on investment;

(ii) depreciation;

(iii) ongoing operation and maintenance costs;

(iv) taxes; and

(v) costs of transmission and other ancillary expenses directly allocable to transmitting electricity generated from a project meeting the specifications of this paragraph;

(2) provides a current return on construction work in progress, provided that recovery of these costs from Minnesota ratepayers is not sought through any other mechanism;

(3) allows recovery of other expenses incurred that are directly related to a renewable energy project, including expenses for energy storage, provided that the utility demonstrates to the commission's satisfaction that the expenses improve project economics, ensure project implementation, advance research and understanding of how storage devices may improve renewable energy projects, or facilitate coordination with the development of transmission necessary to transport energy produced by the project to market;

(4) allocates recoverable costs appropriately between wholesale and retail customers;

(5) terminates recovery when costs have been fully recovered or have otherwise been reflected in a utility's rates.

(b) A petition filed under this subdivision must include:

(1) a description of the facilities for which costs are to be recovered;

(2) an implementation schedule for the facilities;

(3) the utility's costs for the facilities;

(4) a description of the utility's efforts to ensure that costs of the facilities are reasonable and were prudently incurred; and

(5) a description of the benefits of the project in promoting the development of renewable energy in a manner consistent with this chapter.