Xcel Energy®

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January 20, 2015

—Via Electronic Filing—

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

RE: EXCEPTIONS AND CLARIFICATIONS TO ALJ REPORT
XCEL ENERGY'S APPLICATION FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC SERVICE IN THE STATE OF MINNESOTA
DOCKET NO. E002/GR-13-868

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Exceptions and Clarifications to the Administrative Law Judge's *Findings of Fact, Conclusions of Law and Recommendations* (ALJ Report) issued December 26, 2014 in the docket referenced above.

If you have questions or need additional information, please contact me at (612) 215-4663 or aakash.chandarana@xcelenergy.com.

Sincerely,

/s/

AAKASH H. CHANDARANA
REGIONAL VICE PRESIDENT
RATES AND REGULATORY AFFAIRS

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David C. Boyd	Commissioner
Nancy Lange	Commissioner
Dan Lipshultz	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC SERVICE IN MINNESOTA

Docket No. E002/GR-13-868

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I. INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, respectfully submits these Exceptions and Clarifications to the Administrative Law Judge's Findings of Fact, Conclusions of Law, and Recommendations (the ALJ Report) in this proceeding. In compliance with the Commission's December 29, 2014 Notice of Schedule for Filing Exceptions to the ALJ's Report, revised financial schedules and rate design recommendations were previously filed on January 9, 2015, and electric sales and customer actual data through December 2014 and updates to property tax expense were previously filed on January 16, 2015.

At the outset, the Company recognizes that in many ways this case looks a lot like our last electric rate case as many of the drivers of our revenue deficiency remain the same. In addition, several issues, such as when to place the Monticello LCM/EPU Program in-service and recoverability of the qualified pension 2008 Market Loss, are in dispute again. There are, however, several important differences between the two cases that are worth noting.

First, the Company has presented a series of novel proposals in this case. We are the first utility in the State to use the Multi-Year Rate Plan construct. Not only did this require us to enter untested waters at times, such as with our interim rate refund proposal, but it also allowed us to build upon the Commission's decision in the last case to use the surplus theoretical Transmission, Distribution, and General (TDG) depreciation reserve to moderate rates. In this case, we proposed a comprehensive suite of rate moderation tools to provide our customers with more predictable rate changes. As it pertains to rate design, the Company became the first electric utility in the State to propose revenue decoupling.

Second, the record before this Commission is more robust and substantial. The Company's initial case was more detailed and comprehensive than before and, with the assistance of the Department of Commerce, the Office of the Attorney General, and other intervening parties, the record was further developed and refined through a thorough and comprehensive contested case process.

Lastly, the number of disputed revenue requirement issues was narrowed during the contested case process. The Company worked with the Department and other stakeholders to resolve several issues that arose during the proceedings. Also, due to the unique nature of this case (primarily that it is a multi-year rate plan and a final order is expected in the second quarter of 2015), the Company and Department were able to resolve two issues that have frequently arisen in recent rate cases – sales forecast and property taxes. The resolutions reached by the parties are well supported on the record, which confirm they are in the public interest. We appreciate the dedication of the Parties to this proceeding and their willingness to work toward resolution of contested issues where possible.

The ALJ recognized the robust nature of the record in this proceeding and performed a thorough analysis of the detailed revenue requirement, rate moderation, and rate design issues. We believe the ALJ Report is well reasoned and balanced in many areas, and for that reason we defer to the ALJ in those instances. However, we do not agree with the ALJ Report in all respects, and our Exceptions are limited to those areas of particular concern. Specifically, our Exceptions address the ALJ's recommendations with regard to the Monticello LCM/EPU in-service date and ROE.

Because the schedule for this proceeding does not anticipate replies to the Parties' Exceptions, we also address key issues where we generally agree with the ALJ Report and underscore why we believe the ALJ reached a correct result with respect to matters including pension, Paid Leave/Total Labor costs, recovery of the Prairie Island EPU, and CWIP/AFUDC accounting. We also briefly support the ALJ's acceptance of the resolution of certain issues, including sales forecast and property taxes.

We note that in some areas the ALJ distinguished between issues that require a detailed focus on the application of law to fact versus issues that involve broader policy considerations. In particular, the ALJ noted that the ultimate application of our proposed rate moderation tools to the revenue requirement in this case is a policy matter for the Commission's consideration. We agree with this conclusion, and similarly believe the outcomes of the Department's proposed "Passage of Time" adjustment, revenue decoupling and rate design turn in part on the Commission's policy preferences and interpretation of its prior orders. We therefore provide additional discussion about rate moderation and the "Passage of Time" adjustment, and explain our reason for taking exception to the ALJ's findings regarding revenue decoupling and several rate design matters.

Despite our acceptance of the ALJ's Report in many respects, the Company respectfully requests that the Commission consider refining it or making additional decisions in the manner set forth in these Exceptions and Clarifications. In addition to adopting the Exceptions and Clarifications presented here, we believe accepting the findings, recommendations and conclusions of the ALJ will result in just and reasonable rates.

We organize the remainder of this filing within the following sections:

- *Revenue Requirement Exceptions* – we explain our reasons for taking exception to the ALJ's findings and recommendations regarding the Monticello LCM/EPU in-service date, and ROE.
- *Revenue Decoupling Exceptions* – we explain our reasons for taking exception to the ALJ's findings and recommendations regarding revenue decoupling.
- *Rate Design Exceptions* – we explain our reasons for taking exception to the ALJ's findings and recommendations regarding our Class Cost of Service Study, revenue apportionment and interruptible rates.
- *Rate Moderation* – we outline several considerations that we believe could be evaluated by the Commission as part of its deliberation of using rate moderation in this case.
- *Other Revenue Requirement Matters* – we provide the reasons we support the ALJ's findings and recommendations regarding several disputed and resolved revenue requirement issues.

II. REVENUE REQUIREMENT EXCEPTIONS

A. Monticello LCM/EPU

The issue with respect to the Monticello LCM/EPU Program in this case is, as in the Company's last rate case, whether the Program is "used and useful" and therefore "in service" during the test year for purposes of setting rates.[1]

In the Company's last rate case (Docket 12-961), the Company initially sought to include costs of the Monticello LCM/EPU program in rates. The ALJ and

[1] ALJ Report at ¶ 57.

Commission declined, finding that because the Company did not have its initial license amendments necessary to operate the plant at uprate levels, the asset was not yet used and useful. Because the facts and considerations have changed since that time in a manner that bears further discussion, we provide the following exceptions to the ALJ's recommendation that the EPU portion of the Monticello LCM/EPU Program is not yet "used and useful."

A key difference between this case and the record in the Company's last rate case (Docket No. E002/GR-12-961) is attainment of the licensing necessary for Monticello to operate at uprate levels.[2] We recognize that the plant could not operate at uprated levels prior to achievement of the EPU and MELLLA+ license amendments, resulting in the outcome in our prior rate case. Now that these barriers have been removed, the question facing the ALJ (and the Commission) was whether there should be an operational test – a certain level of MW achieved – that must also be satisfied before the LCM/EPU investments can be considered "used and useful."

The ALJ noted that she "is not suggesting that the plant must operate continuously at 671 MW once the Company receives NRC approval to operate at that level in order for the EPU to be 'used and useful.'"[3] We agree that no operational test is warranted, and that the issue of whether a facility is used and useful depends on both the facts and policy considerations.[4] However, based on the conclusion that the Company did not have NRC authorization to operate Monticello at 671 MW and has not fully ascended to 671 MW, the ALJ recommended that the EPU portion of the Program could not be considered "in service."[5] The ALJ Report further cites to Company witness Mr. Timothy O'Connor for the proposition that authorizations and receipt of approvals from the NRC are needed before the Company can generate

[2]ALJ Report at ¶ 64.
[3]ALJ Report at ¶ 89.
[4]ALJ Report at ¶ 87, n.108.
[5]ALJ Report at ¶ 84.

power at uprate levels.[6] We believe that such findings reflect a potential misapprehension regarding the nature of NRC oversight of nuclear facilities, and treat the NRC oversight we are experiencing as akin to additional licensing. As a result, we respectfully disagree that the EPU is not "used and useful" during the 2014 test year.

As Mr. O'Connor stated in testimony (and which no party rebutted), there is only one Monticello operating license and Monticello has received all the amendments to that license needed to operate the facility at uprate capacity.[7] And as discussed further in the Direct, Rebuttal, and Surrebuttal Testimony of Company witness Mr. Timothy O'Connor, during 2013 and 2014, Monticello underwent a significant degree of NRC oversight and review. The NRC requested various forms of data on a regular basis, including some data points never previously requested.[8] As such, the record makes clear that the plant will be subject to NRC review both before, during, and after it is operating at full uprate capacity.

NRC oversight of the plant and activity approval is ongoing and detailed at all times regardless of any EPU. Indeed, NRC personnel are routinely on site at our nuclear plants, and our licenses contain many requirements we must meet on an ongoing basis to continue, start, or re-start operations. Therefore, it is to be expected that there would be testing of equipment during the ascension process to satisfy NRC considerations.[9] This does not mean, however, that such additional testing is analogous to the operational restrictions we faced prior to receiving the EPU and MELLLA+ license amendments.

At the same time, the capital investment in the project has already been made. In this nuclear regulatory environment, requiring assets and investments to be producing maximum output in order to be "used and useful" is likely to significantly increase current and future regulatory lag between nuclear capital investments and

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[6]ALJ Report at ¶ 84, 85, 89.
[7]Ex. 53 (O'Connor Rebuttal) at 4-5.
[8]Ex. 53 (O'Connor Rebuttal) at 6-13; Ex. 55 (O'Connor Surrebuttal) at 4.
[9]Ex. 53 (O'Connor Rebuttal) at 7.

cost recovery. We believe the more appropriate test is whether the capital has been deployed for the benefit of customers, as it has in this case.[10] Given the magnitude and importance of such investments, the degree of regulatory lag likely to follow from the ALJ's approach creates risk for the Company, as well as investor uncertainty around the benefits of investing in our nuclear program.

As a result, we propose the following modifications to paragraphs 83, 86, 87, and 90 of the ALJ's Report with respect to the Monticello LCM/EPU, as well as the deletion of paragraphs 84, 85, 88, and 89.

> 83. In the last rate case, the Commission provided that the "Company may be allowed to recover [EPU-related] costs in future rate cases once the EPU is *in service,* subject to the plant being *used and useful* and subject to a determination that the costs - including cost overruns - were prudent." Based on a careful review of the record in this case, the ~~Administrative Law Judge~~ <u>Commission</u> concludes that the Company has ~~failed to~~ demonstrate<u>d</u> that the EPU is currently "in service" and "used and useful~~,~~<u>.</u>" ~~or that the EPU is likely to be during the 2014 test year.~~
>
> 86. The fact that the equipment installed at the plant as part of the LCM/EPU project is currently being used to produce power at the pre-uprate levels ~~of approximately 600 MW does not demonstrate that the EPU is "in service" or "used and useful" as the Company asserts. Similarly, the fact that~~ <u>and</u> the plant <u>has</u> operated at 640 MW ~~briefly~~ during the ascension process <u>illustrates in part that the EPU assets are</u> ~~does not show that the EPU is~~ "used or useful." To be "in service" and "used and useful," the EPU capital investment needs to be in use for its intended purpose. <u>Here, the EPU assets are operating to increase the safety and reliability of the plant, have helped the plant provide higher MW output for the benefit of customers, and are going through typical processes in the nuclear industry to achieve full capacity. This is little different than any new plant in service during its burn-in period. In addition, the Company's capital has been deployed for the Program and delaying recovery until the plan achieves maximum uprate capacity would unreasonably contribute to regulatory lag given the stringent NRC guidelines applicable to any nuclear facility.</u>
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> 87. The two "common facility" cases relied on by the Company to argue that the EPU should be considered "used and useful" because the LCM/EPU

[10] Xcel Energy Initial Br. at 40-42 ((citing *State ex rel. Utilities Comm'n v. Eddleman*, 358 S.E.2d 339, 352 (N.C. 1987) and *State ex rel. Missouri Pub. Serv. Co. v. Fraas*, 627 N.W.2d 882, 889 (Mo. Ct. App. 1982)).

equipment is being used to produce power at pre-uprate levels are both distinguishable on their facts. Both cases address the question of whether common facilities, such as switching stations, parking lots, and administration buildings, are properly included in rate base where the facilities are intended to support multiple generation units but only one unit is in-service. In those cases, recovery was allowed. Here, there is a dispute in the Monticello LCM/EPU prudence proceeding as to whether a portion of LCM/EPU assets should be allocated to the EPU, or whether the LCM/EPU is a single, integrated Program. While that issue is not resolved in this docket, there is no dispute that the equipment utilized for purposes of the EPU is much the same equipment – and therefore involves the same costs – as the equipment installed for LCM purposes. As such, the common facility cases may have merit depending on the outcome of the prudence proceeding. ~~The issue in this case, however, does not involve the recovery of costs for common facilities, like a parking lot, necessary for the operation of one or more nuclear units. Rather, this case involves the costs associated with equipment designed to increase the plant's generating capacity that is not being used as intended. Moreover, the Commission already concluded in the last rate case that the EPU was not "in service" or "used and useful" even though the LCM/EPU project equipment was being used to generate electricity at pre-EPU levels at that time.~~

90. Because the Company has ~~failed to~~ demonstrated that the EPU is "used and useful," the ~~Administrative Law Judge~~ Commission agrees with the ~~Department~~ Company that the EPU portion of the LCM/EPU project should be ~~removed from~~ included in the 2014 and 2015 rate base ~~and the associated depreciation expense should be removed from the test year as well. With regard to the 2015 Step, the Administrative Law Judge agrees with the Department that the Company should be allowed to include the EPU costs in the 2015 Step subject to refund as part of the MYRP refund process~~.

We recognize the Commission may disagree with us and adopt the ALJ's conclusions regarding the "used and useful" standard, as well as the ALJ's remedy that allows the Company to place the LCM/EPU Program in-service during the 2015 Step consistent with the Department's recommendation. Should the Commission take this path, we accept the Department's recommended disallowance for the 2014 Test Year, including how it was calculated, with one exception – we respectfully propose that the outcome should be modified to recognize that significant EPU capital assets are being utilized and must be depreciated at Monticello during the test year, consistent with the MCC's proposal in this proceeding.

There is no dispute that the capital investment in the LCM/EPU Program has been deployed, or that the assets developed through the LCM/EPU Program are being used to generate electricity at Monticello and have provided benefits apart from the increased plant capacity such as increased efficiency, safety, and reliability.[11] In addition, whether the LCM/EPU assets are generating 600 MW or 671 MW, for accounting purposes the Company must recognize that the useful life of these assets is underway and must depreciate the investment regardless of the maximum level of MW output. In light of these considerations, we continue to believe it is appropriate to allow the Company to defer the 2014 depreciation expense.

This outcome has the further benefit of consistency with the Commission's Sherco 3 decision in our last rate case (Docket E0002/GR-12-961), recognizing that the Company must pay property taxes and incur depreciation expense on the facility even during extended outage periods:

> Property taxes are an unavoidable cost that Xcel incurs regardless of whether the unit is operating, and the Company should be able to recover this expense while it works to repair the unit and restore it to service. Additionally, the Commission will allow Xcel to defer the unit's 2013 depreciation expense.[12]

The Commission concluded that this result struck the correct interest between shareholders and ratepayers, and that "allowing the depreciation expense recognizes that Xcel's investment has provided to ratepayers in the past and will provide once Sherco 3 is up and running."[13] Likewise, the Company has made significant investments in the Monticello plant on behalf of customers and these investments are presently serving safety and reliability purposes for customers; allowing deferral of

[11]Ex. 51 (O'Connor Direct) at 20-21; Ex. 53 (O'Connor Rebuttal) at 14.
[12] 12-961 Order at 23.
[13] 12-961 Order at 23.

depreciation expense recognizes the importance of these investments and their impact on the Company.

Furthermore, while the Commission's Sherco 3 decision depended in part on relieving ratepayers from bearing the costs of the unit while it was not running (and therefore providing no benefit to ratepayers), the Monticello assets are in use and providing benefits to ratepayers – if not the maximum possible output – during all of this rate case test year. And while the ALJ Report distinguishes Sherco 3 because "the EPU has not yet been authorized by the NRC to operate as intended,"[14] in the Company's 2012 rate case it was also true that Sherco 3 was not yet fully operational following its extended outage.[15] Thus, the parallel holds. Finally, "[d]eferral recognizes that, although the unit was not used and useful during the 2013 test year, it remains a valuable asset and an integral part of the Company's generating fleet."[16] The same is true of Monticello.

To reflect this outcome, we recommend the following alternative modifications to Paragraphs 90 and 91 of the ALJ Report:

> 90. Because the Company has failed to demonstrate that the EPU is "used and useful," the ~~Administrative Law Judge~~ Commission agrees with the Department that the EPU portion of the LCM/EPU project should be removed from the 2014 rate base. However, the Commission agrees with the Company that it is appropriate to allow the Company to defer ~~and~~ the 2014 depreciation expense ~~should be removed from the test year as well~~. This outcome recognizes the Company's investment on behalf of customers, that the EPU assets are being used, if not to their full intended purpose, and that the EPU assets are providing benefits to ratepayers. Deferral further recognizes that, although the unit was not fully used and useful during the 2014 test year, it remains a valuable asset and an integral part of the Company's generating fleet. With regard to the 2015 Step, the Administrative Law Judge agrees with the Department that the Company should be allowed to include the EPU costs in the 2015 Step subject to refund as part of the MYRP refund process.

[14] ALJ Report at ¶ 91.
[15] 12-961 Order at 20.
[16] 12-961 Order at 23.

91. Finally, the ~~Administrative Law Judge~~ Commission concludes that MCC's proposed treatment of the Monticello costs is not reasonable. MCC's proposal, which leaves the EPU costs in rate base but defers recovery of the 2014 depreciation expense, is inconsistent with the Administrative Law Judge's conclusion that the EPU is not yet "used and useful." In addition, MCC's suggestion that the delay in the use of the EPU should be viewed as an unplanned outage, like at Sherco Unit 3, is, however, supported in the record because the Monticello EPU, like Sherco 3 at the time of the Commission's Order in the Company's last rate case, ~~lacks support in the record because the EPU has not yet been authorized by the NRC to operate as intended~~ is not yet operational but is anticipated to be operating at full capacity before the conclusion of this rate case. ~~It is not reasonable to characterize the current situation as a temporary outage when the EPU has not yet been placed in service.~~ For these reasons, the Commission finds that it is appropriate to allow deferral of the 2014 depreciation expense associated with the Monticello EPU. ~~the Administrative Law Judge recommends that the Commission reject MCC's proposed treatment of the EPU capital-related costs.~~

Lastly, we agree with the ALJ's conclusion and the Department's stated position at the evidentiary hearing that if the Monticello plant is considered placed in service in 2015 rather than 2014, the plant should not be required to be in service on January 1, 2015 to avoid a refund of all 2015 EPU costs included in the 2015 Step.[17] Rather, if rates for our 2015 Step assume a January 1, 2015 in-service date and the plant is placed in service later than that day, any 2015 Step refund would be adjusted to reflect the amount of time the EPU is in service during 2015. We believe this outcome is consistent with the parties' agreed refund process related to the 2015 Step[18] and is a fair outcome that recognizes the benefit the increased capacity of Monticello will provide to customers in 2015.

B. Return on Equity

While the Company supports the ALJ's analysis as a reasonable floor for the Commission's deliberations, our analyses continue to indicate that the Commission

[17]ALJ Report at ¶ 90 and note 109 (citing Tr. Vol. 5 (Campbell) at 58; Ex. 140 (Heuer Opening Statement) at 6-7).
[18]Ex. 140 (Heuer Opening Statement) at 6-7).

has the discretion to select a ROE between 9.77 percent and 10.25 percent. There are several unique circumstances surrounding this rate case that support our recommendation: (1) this is a MYRP and not a traditional rate case; (2) recognized prolonged financial market volatility; (3) ROEs below the range of 9.77 percent to 10.25 percent are approaching those of gas and distribution-only electric companies and no longer reflect the risk of vertically integrated electric utilities; (4) setting an ROE below 9.83 percent would be the second consecutive ROE reduction for the Company; and (5) it is in our customers' interest not to erode ROE during a period of major capital expansion, as investors lose confidence that the Commission is supportive of the investments we are making to continue to provide safe and reliable service.

We believe the ALJ Report is correct in several respects. First, the ALJ recognized that both the Company's and the Department's ROE analyses were sound and merited "serious consideration" by the Commission.[19] This is consistent with the Company's and the Department's use of similar screening methods for their comparable groups and Commission-approved methods to perform their discounted cash flow analyses.

The ALJ then appropriately moved from her recommendation in the last case, where she recommended the Department's ROE amount proposed in the Department's Surrebuttal Testimony.[20] The ALJ Report acknowledges that the ROE approved in this case will be the ROE that spans the entirety of the Company's MYRP, which makes this case different from prior rate cases.[21] The ALJ also noted that in this case, the single point-in-time snapshot represented by the Department's

[19] ALJ Report at ¶ 377.
[20] ALJ Report at ¶ 382.
[21] ALJ Report at ¶ 383.

Surrebuttal ROE recommendation may not control for market anomalies that were present at the time the Department performed its analysis.[22]

Last, the ALJ's recommendation incorporates the analysis the Commission has utilized in other utilities' recent rate cases, which averaged the ROE proposals presented throughout the rate case to control for the effects of any market anomalies present in a single point-in-time approach.[23] More specifically, in the MERC Order, the Commission noted its concerns regarding an 11 basis point change between the Department's Direct and Surrebuttal DCF results and recognized that single time period (in that case, 32 days) did not sufficiently dampen market price volatility.[24] On the current record, the Department's electric and combination company proxy groups' dividend yields fell by 54 and 26 basis points, respectively, between the Department's initial analysis and its Surrebuttal position.[25] These changes reflect a degree of market volatility that is up to five times greater than the volatility that was of concern to the Commission in the MERC case.

While the Company supports the ALJ's analysis as a reasonable floor for the Commission's deliberations, our analyses continue to indicate that an ROE above 9.77 percent is reasonable for a vertically-integrated utility entering a MYRP. Other large vertically integrated utilities have also been granted ROE's above 9.77 percent in 2014. As the Company noted during the proceedings, the Company's currently authorized ROE of 9.83 percent falls in the bottom one-third of returns authorized from 2012 through May 2014 for utilities that provide generation, transmission, and

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[22]ALJ Report at ¶ 383. In particular, the ALJ Report notes that "the record shows that the dividend yields used in the Department's Surrebuttal Testimony were significantly lower than the dividend yields used in its Direct Testimony…. These decreased dividend yields were the result of unusually high stock prices during the June-July 2014 time period used in the Department's Surrebuttal Testimony. Since that time, utility stock prices have declined relative to the overall stock market and moved more in line with historic expectations. As a result, the Department's updated 30-day dividend yields included in its Surrebuttal Testimony may reflect a short-term anomaly.") (internal citations omitted).

[23]ALJ Report at ¶ 383 (citing to *Petition of Minnesota Energy Resource Corporation for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-011/GR-13-617, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER (Sept. 12, 2013) (MERC Order)).

[24] MERC Order at 31.

[25] ALJ Report at ¶ (citing Hevert Opening Statement at 55-56 and comparing Exs. 402 (Amit Direct) at Attachments EA-13, EA-23 with Ex. 403 (Amit Surrebuttal) at Attachments EA-SR-1, EA-SR-5.

distribution services.[26] Additionally, and by way of reference, the average actual ROEs authorized for vertically integrated electric utilities in the third quarter of 2014 was 9.89 percent.[27] Further, a second successive ROE decrease for the Company could have a disproportionately negative effect.[28] These trends indicate that an ROE somewhat above 9.77 would be reasonable and appropriate.

As a result, the Company proposes the following changes to the ALJ's recommendations:

> 373. After carefully considering the evidence in the record and the arguments of the parties, the Administrative Law Judge recommends that the Commission approve a Return on Equity of 9.83 ~~9.77~~ percent. The reasons for this recommendation are set forth below.
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> 385. The reasonableness of a 9.77 percent ROE for the Company is confirmed by other evidence in the record. First, a 9.77 percent ROE is similar to the 9.85 ROE calculated by, the weighted CAPM results provided in the Department's Surrebuttal Testimony. In addition, the Company's need to access capital for its substantial capital investment plans strongly suggest that a 9.77 percent ROE is more reasonable than the 9.64 ROE recommended by the Department in Surrebuttal Testimony. A 9.64 percent ROE could send a negative signal to potential investors because it is at the low end of ROEs approved since the beginning of 2014, whereas 9.77 percent reflects the average. <u>The 2-year term of the MYRP and the Company's substantial capital investment plans strongly suggest that a 9.77 percent ROE should be further modified. Further, the Company's currently authorized 9.83 percent ROE was set recently on September 3, 2013.</u> For these reasons, the ~~Administrative Law Judge recommends that~~ Commission <u>will adopt</u> ~~adopted~~ a ROE of 9.83 ~~9.77~~ percent, including flotation costs.

For the reasons set forth above, we respectfully recommend modification of the ALJ's conclusions with respect to the Monticello LCM/EPU, and ROE.

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[26] Tr. Vol. 1 (Hevert) at 59.

[27] See Edison Electric Institute Rate Case Summary for Q3 2014 (http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/QtrlyFinancialUpdates/Documents/QFU_Rate_Case/2014_Q3_Rate_Case.pdf).

[28] Tr. Vol. 1 (Hevert) at 60.

III. REVENUE DECOUPLING

The Company appreciates the ALJ's detailed analysis of the Company's partial revenue decoupling mechanism ("RDM") for its Residential and C&I Non-Demand customers.[29] The Company's RDM is the first electric decoupling proposal made in this State and the ALJ's detailed and thorough analysis has helped advance the understanding of how decoupling may impact electric customers. The ALJ concluded that it is reasonable to implement decoupling for the Company.[30] The Company agrees with the ALJ, but is concerned that implementing specific design elements may result in an asymmetrical mechanism that is ultimately both unreasonable and unfair.

The Commission has stated it has an interest in the ongoing assessment of the merits of decoupling as a means of promoting energy efficiency and conservation.[31] In this spirit, the Company voluntarily brought a decoupling proposal forward for consideration. The Company's proposal is gradual, as it does not change the status quo with customers regarding weather. The proposal is also limited to those classes that pay the highest portion of fixed costs through variable rates and therefore are associated with the highest conservation disincentive.[32] The Company's proposal is symmetrical in that RDM billing adjustments are used to make sure the Company collects the weather normalized revenue per customer approved in this case – no more and no less.[33] And the Company's proposal is designed to provide sufficient information to contribute to the Commission's ongoing assessment of decoupling.[34]

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[29] The Company's proposed RDM is a "partial" decoupling mechanism because it excludes weather effects. Ex. 109 (Hansen Direct) at 2.

[30] ALJ Report at ¶ 892.

[31] *In the Matter of an Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas For Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 47 (June 9, 2014).

[32] Ex. 25 (Sparby Direct) at 30; Ex. 109 (Hansen Direct) at 13-14; Ex. 110 (Hansen Rebuttal) at 9, 13. The Company also explained application to the Residential and C&I Non-Demand classes is straightforward (due to rate design and weather normalization of energy) and avoids problems associated with the sales volatility seen in other classes. Ex. 109 (Hansen Direct) at 13-14; Ex. 110 (Hansen Rebuttal) at 12-13.

[33] Ex. 109 (Hansen Direct) at 2, 9-19; Ex. 110 (Hansen Rebuttal) at 11. The Company agrees with the ALJ that the phrase RDM billing adjustment more accurately reflects the adjustments ratepayers experience with a decoupling mechanism and will use that phrase throughout its exceptions. *See* ALJ Report at ¶ 843, n. 1282.

[34] Ex. 109 (Hansen Direct) at 18-19; Ex. 110 (Hansen Rebuttal) at 4, 9, 13; Ex. 417 (Davis Direct) at 22-23.

The ALJ recommends two major modifications to the Company's proposal. First, the ALJ agrees with the Department that the decoupling mechanism should be a full decoupling mechanism that includes the effect of weather.[35] Second, the ALJ recommends RDM billing adjustments be subject to a hard cap, again, as recommended by the Department.[36] The Company is concerned with both recommendations, as the resulting mechanism is neither gradual nor symmetrical; it also does not sufficiently address the Company's disincentive to promote conservation. Such outcomes are especially concerning when the Company voluntarily presented a well-developed, fair and reasonable proposal.

A. Full versus Partial Decoupling[37]

The ALJ concluded full decoupling is a more reasonable approach than partial decoupling.[38] The ALJ correctly noted that "either a full or partial RDM would eliminate the Company's disincentive to encourage energy conservation and efficiency."[39] But, according to the ALJ, full decoupling is necessary to avoid an adverse impact on customers.[40] The Company respectfully disagrees with the ALJ that partial decoupling will adversely impact customers.

According to the ALJ, the Department's analysis "has demonstrated that the Company's partial decoupling RDM is likely to result in the Company's residential customers paying substantially more than under a full decoupling RDM, and could result in ratepayers being overcharged."[41] This statement is problematic for three reasons. First, the statement that customers could be "overcharged" under partial decoupling "implies that customers can be charged amounts in excess of the rates

[35] ALJ Report at ¶ 910.
[36] ALJ Report at ¶¶ 933-934.
[37] ALJ Report at ¶¶ 898-910.
[38] ALJ Report at ¶ 910.
[39] ALJ Report at ¶ 910.
[40] ALJ Report at ¶ 910.
[41] ALJ Report at ¶ 910.

approved by the Commission in a given case, which is not correct."[42] Under the Company's proposal, RDM billing adjustments would be limited to those amounts necessary to achieve the weather normalized revenue per customer approved in this case – no more and no less.[43] Thus, the Company's proposed RDM cannot result in any "overcharge."

The Company also respectfully disagrees that the Department "has demonstrated the Company's partial RDM is *likely* to result in the Company's residential customers paying substantially more than under a full decoupling RDM."[44] The Company demonstrated that the Department's conclusions are dependent on the pilot period sharing economic and weather characteristics with the recent past. If the pilot period has slightly different weather patterns, the purported advantages of full decoupling over partial decoupling either vanish or become disadvantages.[45] Given this variability and the fact that weather is unrelated to addressing the Company's disincentive to promote conservation, the Company's proposed gradual, partial decoupling mechanism is the more reasonable option.

Finally, the Commission has previously interpreted the phrase "without adversely affecting ratepayers" in a way that is not consistent with the Department's position. According to the Commission, the phrase "without adversely affecting ratepayers" is "a safeguard against adversely affecting utility ratepayers overall or out of proportion to the purposes of the statute and the benefits derived by ratepayers from the Decoupling Program in question."[46] The statutory provision is not "an absolute requirement prohibiting an increase in rates or [] bills paid by any

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[42] ALJ Report at ¶ 844, n. 1282.
[43] Ex. 417 (Davis Direct) at 33; Ex. 109 (Hansen Direct) at 9-12.
[44] ALJ Report at ¶ 910 (citing Ex. 417 (Davis Direct) at 32)(emphasis added).
[45] Ex. 110 (Hansen Rebuttal) at 5-8.
[46] *In the Matter of an Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G008/GR-08-1075, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 13 (Jan. 11, 2010).

ratepayers."[47] The Company's partial decoupling mechanism does not change the Company's relationship with its customers as it pertains to weather. The exclusion of weather from the mechanism therefore does not affect customers because there is no change from the status quo as it pertains to weather. Even if one did accept the Department's position that the exclusion of weather from the RDM would increase potential RDM billing adjustments, the Commission has concluded that the statute is not "an absolute requirement prohibiting an increase in rates or [] bills paid by any ratepayers."[48] The Company's proposed RDM does not affect customers out of proportion to the purposes of the statute and the benefits derived by ratepayers from the [RDM]"[49] and therefore does not adversely affect ratepayers.

The ALJ, the Company, the Department and the CEIs all agree that the Company's partial decoupling mechanism eliminates the disincentive to promote conservation.[50] The Company's preference for partial decoupling is consistent with its desire for a gradual approach.[51] Industry experts and the Commission have both concluded that decoupling works best when the utility supports the key design elements.[52] And the Company's proposal will assist the Commission in its ongoing assessment of the merits of decoupling as a means of promoting energy efficiency and

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[47] *In the Matter of an Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G008/GR-08-1075, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 13 (Jan. 11, 2010).
[48] *In the Matter of an Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G008/GR-08-1075, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 13 (Jan. 11, 2010).
[49] *In the Matter of an Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G008/GR-08-1075, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 13 (Jan. 11, 2010).
[50] ALJ Report at ¶ 910; Ex. 109 (Hansen Direct) at 12; Ex. 417 (Davis Direct) at 18; Ex. 290 (Cavanagh Direct) at 7; Tr. Vol. 4 at 141-142 (Davis).
[51] Ex. 109 (Hansen Direct) at 14; Ex. 110 (Hansen Rebuttal) at 9.
[52] ALJ Report at ¶ 909 (citing Ex. 294 (Cavanagh Rebuttal) at 6); *In the Matter of an Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas For Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 48 (June 9, 2014)("The Commission concludes that full decoupling has substantial potential to align the Company's interests with the public's interest in energy efficiency.).

conservation.[53] For these reasons, the Company requests ALJ Report Finding 910 be amended as follows:

> 910. ~~Based on the record in this case, the Administrative Law Judge concludes that full decoupling is a more reasonable approach than partial decoupling for the Company's residential and small business customers who would be subject to the RDM adjustments. The Department has demonstrated that the Company's partial decoupling RDM is likely to result in the Company's residential customers paying substantially more than under a full decoupling RDM, and could result in ratepayers being overcharged.[1362] Moreover, the~~ The record shows that either a full or a partial RDM would eliminate the Company's disincentive to encourage energy conservation and efficiency.[1363] T~~o avoid an adverse impact on ratepayers subject to the new RDM, the Administrative Law Judge recommends that the Commission order the Company to implement its RDM with full decoupling.~~ Given the Company's desire to take a gradual approach, the Company's preference for partial decoupling and the recognized benefits of aligning the Company's interests with public's interests in energy efficiency, the Company shall implement a partial RDM on a pilot basis.

B. Type and Limit of RDM Cap[54]

The ALJ recommends the Commission adopt the Department's hard cap proposal.[55] A hard cap is problematic for two reasons: first, a hard cap reintroduces a disincentive to promote energy efficiency and therefore undermines the purpose of decoupling.[56] Second, the hard cap results in asymmetrical ratemaking that is unfair when paired with full decoupling. The Company respectfully requests the Commission order the Company to implement its RDM with a soft cap.

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[53] *In the Matter of an Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas For Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 47 (June 9, 2014).
[54] ALJ Report at ¶¶ 911-934.
[55] ALJ Report at ¶ 934.
[56] Ex. 110 (Hansen Rebuttal) at 10; Ex. 294 (Cavanagh Rebuttal) at 4-5.

The Company's RDM proposal is subject to a true cap – the weather normalized revenue per customer established in this case.[57] The soft cap proposed by the Company limits the variability of RDM adjustments and guarantees the Company remains indifferent to energy conservation at all usage levels, consistent with the statutory purpose of decoupling.[58] In contrast, a hard cap reintroduces a disincentive to promote conservation at levels above the hard cap, a problem that is not reasonably addressed by citing to the Company's conservation incentives.[59]

Combining full decoupling with a hard cap also results in asymmetrical ratemaking.[60] Under the Department's proposal, any excess revenue due to weather must be returned to customers, but the Company is limited in its ability to collect any weather-related shortfalls. This is a fundamentally unfair scenario where the Company retains significant downside weather-related risk. Conversely, the Company's proposal is fair to both the Company and to customers because it limits recovery to the weather normalized revenue per customer established in this case – no more and no less.[61]

The record clearly demonstrates that a hard cap reintroduces a disincentive associated with conservation and is thus inconsistent with the purpose of decoupling.[62] The record also shows that most electric decoupling mechanisms have soft caps or no caps at all.[63] The Company therefore asks that ALJ Report Findings 868, 933 and 944 be amended as follows:

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[57] Ex. 417 (Davis Direct) at 33; Ex. 109 (Hansen Direct) at 9-12.

[58] Minn. Stat. § 216B.2412; Ex. 110 (Hansen Rebuttal) at 11.

[59] Xcel Energy Initial Brief at 147; Xcel Energy Reply Brief at 132.

[60] The asymmetry is magnified when the cap is set at 3 percent of base revenues, as recommended by the ALJ. ALJ Report at ¶ 934. The Company acknowledges the ALJ's recommendation to measure the cap against all revenues (i.e. including fuel and applicable riders) yields a larger cap than if the cap was only calculated according to base revenues. *See* ALJ Report at ¶ 934, n. 1397.

[61] Xcel Energy Initial Brief at 148 (citing Minn. Stat. § 216B.03 and noting that by definition, the revenue per customer established in this case will be set at a just and reasonable level); Ex. 417 (Davis Direct) at 33; Ex. 109 (Hansen Direct) at 9-12.

[62] Ex. 110 (Hansen Rebuttal) at 10-11; Ex. 294 (Cavanagh Rebuttal) at 4-5.

[63] Ex. 110 (Hansen Rebuttal) at 10 (citing Ex. 109 (Hansen Direct), Schedule 2). The Company's proposed cap level is also lower than typical caps for electric utilities. Ex. 110 (Hansen Rebuttal) at 12.

868. The Company stated that most electric decoupling mechanisms have soft caps or no caps at all ~~are used in the majority of jurisdictions where decoupling has been adopted~~.[1315]

933. ~~The Administrative Law Judge concludes that the Company's proposed soft cap on RDM billing adjustments would place an unreasonable burden on ratepayers. The Administrative Law Judge also finds that the Company has not shown a need for more than a 3 percent cap. Based on data from 2009-2013, only the Residential with Space Heating ratepayers would have exceeded a 3 percent cap, and that cap would have been exceeded only in one year, 2012. 647.~~ The Company's proposed soft cap is a reasonable means of managing the variability of RDM adjustments from year to year and should be adopted. A hard cap reintroduces a disincentive to promote energy efficiency, thereby undermining the purpose of decoupling. Further, the Department's reliance on the DSM financial incentive conflates two programs the legislature has deemed to be separate.

934. ~~Therefore, the Administrative Law Judge recommends that the Commission adopt the Department's 3 percent hard cap on all revenues, including fuel and applicable riders, as part of the Company's RDM.[1397] This recommendation balances the need for the Company to earn its full authorized revenue with the requirement that ratepayers not be adversely affected, and is reasonable given that this electric RDM program would be the first for an electric utility in Minnesota.~~ The cap level and measurement proposed by the Company is consistent with national practice and should be adopted. If the Commission chooses to require the Company to implement full decoupling, then the cap should be set at 10 percent of base revenues.

IV. RATE DESIGN

Rate design is a quasi-legislative function that largely rests on policy determinations.[64] The Commission has broad discretion in its rate design analysis,[65]

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[64] *St. Paul Area Chamber of Commerce v. Minn. Pub. Serv. Comm'n,* 312 Minn. 250, 260, 251 N.W.2d 350, 357 (1977).

[65] *St. Paul Area Chamber of Commerce* 251 N.W.2d at 357 ("In ascertaining whether or not the statute has been contravened, the district court must give wide latitude to the commission in allowing it to consider many factors which might not ordinarily be considered by a court, as we have explained above. This is so because, while the court is qualified to review agency findings when an agency acts in a quasi-judicial manner in factual matters, it is not so qualified to review legislative judgments when social policies must be weighed in the balance.").

and considers a variety of factors in making its assessment.[66] As discussed above, the Company generally agrees with many of the ALJ's findings, including those on rate design, and asks that they be adopted by the Commission. For certain rate design items, however, other reasonable outcomes are supported in the record and the Commission would be well within its quasi-legislative authority to reach conclusions that are different from those reached by the ALJ.

The ALJ is right that the Commission balances competing interests and policy goals in the rate design process.[67] In undertaking this balancing, the Company asks the Commission to: 1) recognize that keeping business rates competitive ultimately helps all customers[68] and 2) grounding rates in cost principles is equitable and encourages the efficient use of resources.[69] The Company believes these considerations should receive particular attention in the Commission's rate design analysis.[70] When these factors are taken into consideration, the Company believes the record supports deviating from the ALJ's conclusions regarding the following rate design topics:

- CCOSS: Treatment of Other Production O&M and Company-owned wind;
- Revenue Apportionment; and
- Interruptible Service Discounts.

Making these changes will ultimately lead to the development of reasonable rates for all customers.

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[66] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E002/GR-10-971, FINDINGS OF FACT, CONCLUSIONS AND ORDER at 14 (May 14, 2012).
[67] ALJ Report at ¶ 665 (citing *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. E002/GR-12-961, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 5 (Sept. 3, 2013).
[68] Ex. 25 (Sparby Direct) at 31; Ex. 26 (Sparby Rebuttal) at 7-9; Ex. 343 (Maini Direct) at 33. *See also* ALJ Report at ¶ 753 (acknowledging that keeping large customers on the system benefits all customers).
[69] Ex. 105 (Huso Direct) at 6, 10; Ex. 107 (Huso Rebuttal) at 9; Ex. 420 (Peirce Direct) at 3.
[70] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E002/GR-10-971, FINDINGS OF FACT, CONCLUSIONS AND ORDER at 14 (May 14, 2012).

A. CCOSS

1. *Other Production O&M*[71]

The ALJ concluded the location method is the most reasonable method identified in the record for classifying Other Production O&M costs.[72] The Company respectfully disagrees with the ALJ's conclusion. First, the Company provided the *only* detailed analysis of Other Production O&M in the record, while proponents of the location method rely only on past practice. Second, the analysis provided by the Company was different from analyses presented in past rate cases and does, in fact, "move the marker closer to cost causation."[73] The Company respectfully requests the Commission find the predominant nature method to be the more reasonable method of allocating Other Production O&M costs in this case.

As part of the Company's last rate case, the Commission ordered the Company to refine the classification of Other Production O&M by "identifying any and all Other Production O&M costs that vary directly with the amount of energy produced" and classifying such costs as energy-related.[74] In response, the Company examined each of the 117 cost items that make up Other Production O&M.[75] The Company's analysis showed: 1) chemicals and water usage vary directly with the amount of energy produced;[76] and 2) other types of Other Production O&M costs could be identified as being primarily fixed (capacity-related) or variable (energy-related) in nature.[77] All parties, including the ALJ, appear to *rely* on the Company's analysis as it relates to

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71 ALJ Report at ¶¶ 718-736.
72 ALJ Report at ¶ 735.
73 ALJ Report at ¶ 735.
74 *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. E002/GR-12-961, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at Order Point 49 (Sept. 3, 2013).
75 Ex. 102 (Peppin Direct) at 19 and Schedule 7.
76 Ex. 102 (Peppin Direct) at 19-20.
77 Ex. 103 (Peppin Rebuttal) at 27.

chemicals and water use and accept that it is reasonable to classify costs that change with the amount of energy produced as being energy-related.[78]

Rather than continuing the analysis of the relationship between each category of Other Production O&M costs and their energy- or capacity-related nature, the Department prefers to rely on proxies to classify the remaining (*i.e.* non-chemicals and non-water) Other Production O&M costs.[79] The Department's use of proxies is problematic for two reasons. First, relying on the Company's analysis for one part of the classification process (*i.e.* the first step of the location method), but rejecting it for another (*i.e.* the second step of the predominant nature method) is fundamentally unreasonable.[80] Second, using proxies (as occurs with both the location method and the overall investment method) may have been reasonable in past cases, but continued reliance is no longer justified in the face of the new analysis performed by the Company. For example, there are $35.1 million in license fees, permits, regulatory expenses and association dues included in Other Production O&M costs.[81] The Company's analysis is able to isolate those costs and classify them as capacity-related, which is appropriate because these costs are completely unrelated to the energy generated at the plant.[82] Under the location method, however, over 75% of license fees are classified as being energy-related. The same is true for computer hardware, software and networking, as these costs that have no relationship with generator output. The Department has presented no explanation why it is reasonable to classify costs that vary directly with the amount of energy produced (*i.e.* chemicals and water use) as energy-related but unreasonable to classify costs that are clearly unrelated to the amount of energy produced (*i.e.* license fees and computer costs) as capacity-

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[78] ALJ Report at ¶ 736 (recommending use of the Location method, the first step of which is to identify costs that vary directly with the amount of energy produced); Ex. 408 (Ouanes Direct) at 35; Ex. 377 (Nelson Rebuttal)at 18; Ex. 343 (Maini Direct) at 25; Ex. 262 (Pollock Rebuttal) at 16-23; Tr. Vol. 4 at 100-101 (Ouanes).
[79] Xcel Energy Initial Brief at 128 (citing Tr. Vol. 4 at 67-68 (Ouanes)).
[80] *St. Paul Area Chamber of Commerce,* 251 N.W. 2d at 357(requiring a quasi-legislative decision to be reasonable).
[81] Ex. 102 (Peppin Direct) at 24.
[82] Ex. 103 (Peppin Rebuttal) at 26-27; Xcel Energy Initial Brief at 128-129.

related. Without an adequate explanation of this contradiction, the Department's support of the location method is not "within the bounds of reasonableness."[83]

Finally, it is important to recognize the predominant nature method is not the same as method previously reviewed and rejected by the Commission.[84] In the Company's 2010 rate case, the XLI recommended using a method described in the NARUC Manual as follows:

> One common method for handling [accounts that contain both demand-related and energy-related components] is to separate the labor expense from the materials expense: labor costs are then considered fixed and therefore demand-related, and materials costs are considered variable and thus energy-related.[85]

This is different from the predominant nature method, which is described as: "[a]nother common method is to classify each account according to its 'predominant' – i.e., demand-related or energy-related – character."[86] The predominant nature method is a more refined analysis than what was proposed by XLI in past cases because it is supported by an examination of each of the 117 different Other Production O&M accounts. Thus, the predominant nature method "move[s] the marker closer to cost causation"[87] than what was presented in previous cases.

The predominant nature method is supported by a detailed analysis of Other Production O&M costs. Parties have relied on the detailed analysis in their support of using the location method to classify Other Production O&M costs. Further, the

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[83] *St. Paul Area Chamber of Commerce,* 251 N.W. 2d at 354.
[84] *See* ALJ Report at 735.
[85] Ex. 103 (Peppin Rebuttal) at 26 (quoting the National Association of Utility Commissioners, Electric Utility Cost Allocation Manual, 66 (Jan. 1992). *See also In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E002/GR-10-971, FINDINGS OF FACT, CONCLUSIONS AND ORDER at 17 (May 14, 2012) ("XLI disputed Xcel's classification of "other" production operation and management costs as 15% demand-related and 85% energy-related. XLI suggests that these costs should be divided into labor-related and materials-and-maintenance-related costs, and that if they were re-classified in that manner, the proper attribution of those costs would be 35% demand-related and 65% energy-related. XLI argues that its preferred division of these costs is appropriate because labor costs are fixed and relate to operating a plant independently of the amount of energy produced by the plant, and therefore relate to demand, while materials and maintenance, as variable costs, relate to energy production and should be attributed to energy.").
[86] Ex. 103 (Peppin Rebuttal) at 26 (quoting the National Association of Utility Commissioners, Electric Utility Cost Allocation Manual, 66 (Jan. 1992).
[87] ALJ Report at ¶ 735.

predominant nature method is considered "common practice," while the locational method is "not standard."[88] The Company therefore respectfully requests ALJ Report Finding 734 be amended as follows:

> 734. The Company's use of the predominant nature method in its proposed CCOSSs is reasonable. The predominant nature method is a refinement of past practice supported by a new analysis. The Company's examination of each of the 117 cost items that make up Other Production O&M avoids the need to rely on proxies in the classification process. The method is also considered "common" practice, while the locational method is "not standard." The Company's proposal is therefore reasonable and should be adopted. ~~The propriety of the Overall Investment method for classifying Other Production O&M Costs has been confirmed in past Company testimony and in past Commission orders. In the last rate case, the Commission required a further refinement of the method through the application of the energy allocator to costs that vary directly with the amount of energy produced and allocation of the remainder of costs on the basis of Plant Production. As noted above, this approach is known as the Location method. In contrast, the Company's application of the Predominant Nature method goes beyond the refinement ordered by the Commission in the last rate case by assigning all remaining costs based on their "predominant nature."~~

The Company also respectfully requests ALJ Report Findings 735 and 736 be deleted in their entirety. Finally, the Company asks ALJ Report Finding 725 be corrected as follows:

> 725. The Company determined that application of the Location method to these costs results in ~~65~~ 35 percent of Other Production O&M costs being classified as capacity-related and ~~35~~ 65 percent energy-related.[1099] Application of the Predominant Nature method, on the other hand, resulted in 78.4 percent of these costs being classified as capacity-related and 21.6 percent as energy related.[1100]

[88] Ex. 103 (Peppin Rebuttal) at 25 (quoting page 66 of the National Association of Regulatory Commissioners, Electric Utility Cost Allocation Manual (Jan. 1992)).

2. *Company-Owned Wind*[89]

The ALJ recommends all Company-owned wind facilities be classified into capacity- and energy-related components using the Plant Stratification methodology.[90] The Company agrees with the ALJ that Plant Stratification has been and remains an appropriate classification methodology for production plant that is added to the system through a normal resource planning process.[91] It is a methodology that mirrors the kinds of decisions that occur in traditional system planning, namely the tradeoff between energy and capacity needs.[92] But Nobles and Grand Meadow were not acquired on that basis: they were built to satisfy a legislative mandate.[93] Thus, there is a fundamental mismatch when Plant Stratification is applied to policy-driven resources.

The Company acknowledges that the Commission has applied Plant Stratification to Nobles and Grand Meadow in past cases.[94] The Company also acknowledges that it has supported applying Plant Stratification to these resources in the past.[95] This case, however, includes new information that highlights the difference between renewable resources that were added to minimize system costs (Pleasant Valley and Borders) and those added to fulfill RES obligations (Nobles and Grand Meadow).[96] The new information justifies taking a renewed look at the

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[89] ALJ Report at ¶¶ 691-709.
[90] ALJ Report at ¶ 709.
[91] *See* ALJ Report at ¶¶ 681, 690.
[92] Ex. 102 (Peppin Direct) at 13-14; Ex. 103 (Peppin Rebuttal) at 10.
[93] ALJ Report at ¶ 706 (noting Nobles and Grand Meadow were built to satisfy a legislative mandate); Ex. 102 (Peppin Direct) at 27-28; Ex. 103 (Peppin Rebuttal) at 17 and Schedule 5 (citing *In the Matter of the Application by Northern States Power Company d/b/a Xcel Energy for a Certificate of Need for the Grand Meadow Wind Farm*, Docket No. E002/CN-07-873, ORDER (Dec. 24, 2007); *In the Matter of the Petition of Northern States Power Company, a Minnesota Corporation, for Approval of Investments in Two Wind Power Projects: 200 MW Nobles Wind Project and 150 MW Merricourt Wind Project*, Docket No. E002/M-08-1437, ORDER APPROVING INVESTMENTS AND EXPENDITURES, FINDING THE NOBLES PROJECT EXEMPT FROM OBTAINING A CERTIFICATE OF NEED, AND ADDING REQUIREMENTS (June 10, 2009)).
[94] ALJ Report at ¶¶ 693, 701.
[95] Ex. 103 (Peppin Rebuttal) at 19-20. While the ALJ is correct that the Company did not make a specific proposal to change the treatment of Nobles and Grand Meadow in the 2012 rate case, it did generally raise the issue of the classification of policy-driven resources. *Compare* ALJ Report at ¶ 698 *with* Ex. 103 (Peppin Rebuttal) at 20 (citing Docket No. E002/GR-12-961, Ex. 60 (Peppin Direct) at 35, in which the Company indicated the Commission may determine a change in the classification of Nobles and Grand Meadow for policy reasons).
[96] Ex. 103 (Peppin Rebuttal) at 17-18.

classification of policy-driven resources.[97] A renewed look is especially important as more policy-driven resources will be added to the system in the next several years.[98] In this kind of environment (*i.e.* when resources are not added based on a balancing of capacity and energy, but rather to meet legislative mandates), it is reasonable to consider whether a blanket rule that applies Plant Stratification to every type of fixed production plant is reasonable, regardless of why the resource was added to the system.

Accordingly, the Company requests ALJ Report Findings 698, 706 and 709 be amended as follows:

> 698. The Company acknowledged in its last rate case that the Commission may determine a change to the classification of Company-owned wind is appropriate. At that time, however, the Company did not make the specific ~~either of these~~ arguments presented in this case. ~~in its last rate case even though costs for both Grand Meadow and Nobles were included in the Company's last rate case filed in November 2012~~.[1067] [Edit to Footnote 1067: *See generally* 12-961 REPORT; Ex. 103, Peppin Rebuttal at 20 (citing Docket No. E002/GR-12-961, Exhibit 60 (MAP-1), Peppin Direct, page 35 in which the Company indicated the Commission may determine a change in the classification of Nobles and Grand Meadow for policy reasons)]
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> …
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> 706. ~~The Administrative Law Judge concludes that the~~ The Company has ~~not~~ demonstrated that it is reasonable to classify the Grand Meadow and Nobles generation facilities differently than other production plant in recognition of the ~~as 100 percent capacity-related. As the Commission noted in its 10-971 ORDER, wind facilities generally replace other energy resources, and "contribute very little to capacity" because they are only available when the wind blows.~~[1078] ~~The Company has failed to provide any evidence that Nobles and Grand Meadow have any different~~

[97] *Peoples Natural Gas Co.*, 413 N.W.2d 607, 615 (Minn. Ct. App. 1987), *pet. for rev. denied* (Minn. App. Apr. 24, 1984)("If an agency's action departs from precedent, it is not arbitrary or capricious if the agency explains the reasons for its departure from the precedent."); *In re Northern States Power Company*, 519 N.W.2d 921, 925 (Minn. Ct. App. 1994)("But the agency is not bound to a rigid adherence to precedent, and where evidence in the record differs from previous cases, results may differ as well.").

[98] *See* Minn. Stat. § 216B.1691, subd. 2f (requiring each public utility to generate or procure sufficient electricity generated by solar energy to service its retail electricity customer in Minnesota so that by the end of 2020, at least 1.5 percent of the utility's total retail electric sales in Minnesota is generated by solar energy).

~~operational characteristics than other wind facilities that would justify classifying them as 100 percent capacity-related. The~~ fact that these facilities were built to satisfy a legislative renewable energy policy. ~~does not change their operational characteristics, and therefore does not provide a rational basis for classifying these facilities as 100 percent capacity-related.[1079]~~

…

709. Pleasant Valley and Borders were added to minimize system costs on the same basis as other production plant. It is therefore reasonable to classify these projects using the Plant Stratification method. As for Nobles and Grand Meadow, there are four alternatives before the Commission:

Table
Percentage of Nobles and Grand Meadow Costs Allocated to Classes

	Residential	**C&I Non-Demand**	**C&I Demand**	**Lighting**
OAG (100% Energy)	28.91%	3.29%	67.37%	0.43%
Department (Plant Stratification)	29.16%	3.31%	67.12%	0.41%
Company (100% Capacity)	34.52%	3.68%	61.80%	0.00%
MCC (Base Revenues)	39.22%	4.03%	55.57%	1.18%

The cost allocation under the Company's proposal reasonably reflects the policy nature of the Nobles and Grand Meadow projects and is reasonable overall; it should be adopted in this case for these specific policy-related resources. ~~The Commission has repeatedly confirmed the Company's use of the Plant Stratification method for the proper classification and allocation of the Company's production plant, including costs of Company-owned wind generation. The application of the Plant Stratification method to wind generation continues to be the most reasonable alternative shown in the record. Accordingly, the Administrative Law Judge recommends that the Commission require the Company to modify its 2014 and 2015 Step CCOSSs to classify the costs of the Grand Meadow and Nobles wind farms on the same basis as its other fixed production plant costs using the Plant Stratification method.~~

The Company also requests ALJ Report Finding 707 be deleted in its entirety.

3. Minimum System Study[99]

The Company agrees with the ALJ that the OAG's proposed adjustments to the CCOSS related to the Company's minimum system study are not reasonable.[100] The OAG's position is not supported in the record, is inconsistent with industry practice, and is contrary to Commission precedent.[101] Further, the Company explained that the OAG's analysis was fundamentally flawed, as it was inconsistent with the NARUC Manual and was based on double-counting.[102] The OAG selectively focused on some data while ignoring other data,[103] resulting in an arbitrary adjustment – a fact acknowledged by the OAG.[104] The record shows that when all data is considered (not just the data selected by the OAG), the Company may actually under-estimate customer-related costs.[105] The ALJ was correct to reject the OAGs arbitrary adjustment.[106]

The Company also agrees with the ALJ's recommendation that the Company update its minimum system study as part of its next rate case.[107] The Company asks,

[99] ALJ Report at ¶¶ 737-745.
[100] ALJ Report at ¶ 745.
[101] Xcel Energy Initial Brief at 129-131.
[102] Xcel Energy Reply Brief at 121-122 (explaining the OAG's "proxy" for the zero-intercept method removed materials costs when the NARUC Manual clearly indicates that a zero-intercept study *includes* materials costs and that the Company's minimum system study already includes an adjustment that accounts for the demand associated with the minimum sized system, making an adjustment for the "materials used…to serve a specific level of demand" unnecessary).
[103] Xcel Energy Reply Brief at 122-123.
[104] Ex. 375 (Nelson Direct) at 26; Tr. Vol. 3 at 249-250 (Nelson).
[105] Xcel Energy Initial Brief at 130-131; Xcel Energy Reply Brief at 122-123; Ex. 70 (Foss Rebuttal) at 4-8; Ex. 103 (Peppin Rebuttal) at 33; Ex. 104 (Peppin Surrebuttal) at 5-6.
[106] *In the Matter of the Application of Northern States Power Company for Authority to Increase Electric Rates*, Docket No. E002/GR-85-558, ORDER at 28-29 ("The ALJ rejected the three modifications [to the Company's CCOSS] suggested by the RUD-AG. He rejected the minimum system adjustment because there is no indication in the record that the RUD-AG's proposed solution does anything but produce an arbitrary number for the amount of customer costs…. The Commission agrees in every respect with the findings of the ALJ regarding the class cost of service study and adopts his findings and supporting discussion as its own.").
[107] ALJ Report at ¶ 744; Ex. 103 (Peppin Rebuttal) at 35; Ex. 104 (Peppin Surrebuttal) at 6; Ex. 375 (Nelson Direct) at 26.

however, that the filing of a zero-intercept study be conditioned on the Company's ability to gather the appropriate information.[108]

Based on the above, the Company requests ALJ Report Findings 744 and 745 be amended as follows:

> 744. ~~The Administrative Law Judge concludes that the~~ The OAG has raised ~~valid~~ concerns regarding the value of the data the Company has used to support its minimum system study. The OAG's analysis contains serious flaws and ultimately results in an arbitrary recommendation. The Company's classification of distribution related costs into customer-related and capacity-related components is reasonable for use in this case. ~~The data presented were last gathered nearly a quarter of a century ago, with no attempt to provide fact-specific updates.~~ Although the analysis under the Zero-Intercept method may be more rigorous than under the Minimum Size method, the NARUC Manual has found that it is more accurate, though the differences between the two methods is relatively small. Further, all Minnesota electric utilities either use the Minimum Size method in their respective cost studies or have been ordered to do so in subsequent rate cases, indicating the Commission does not view the zero-intercept method as being inherently superior to the minimum system method. For these reasons, it may be helpful for the Company ~~should be required~~ to file a zero-intercept analysis of distribution costs in its next rate case if it is able to collect the appropriate data. ~~In addition, because the Minimum Size method is a useful cross check of the Zero-Intercept method, the~~ The Company should also file an updated Minimum Distribution System study as a comparative analysis.
>
> 745. The gathering of more sophisticated and updated distribution cost information in the next rate case will be an ongoing improvement to the CCOSS. Requiring the updating of data and the filing of a zero-intercept analysis (if the Company is able to collect the appropriate data) in the next rate case is a more reasonable approach to addressing the issues raised by the OAG than adjusting the Company's distribution costs by 10 percent in this case.

[108] Ex. 103 (Peppin Rebuttal) at 31, 34-35; Ex. 104 (Peppin Surrebuttal) at 5-6.

4. Allocation of Economic Development Discounts

The Company agrees with the ALJ that economic development discounts should be allocated to customers based on present revenues.[109] The Company's economic development programs are designed to attract and retain large customers,[110] and the ALJ's recommendation appropriately reflects that purpose. Methodologies that allocate more costs to the C&I Demand class than proposed by the Company and XLI ultimately undermine the purpose of the discounts. Because the Present Revenue allocator is consistent with the purpose of the economic discounts and is reasonable overall, the ALJ's recommendation should be adopted.

B. Apportionment[111]

The Company generally agrees with the ALJ that the revenue apportionment in this case should be "closely aligned with [the cost of service]."[112] Cost-based rates promote equity across customer classes and encourage the efficient use of resources.[113] Cost-based rates also can help improve the competitiveness of our business offerings, which ultimately helps all customers.[114] The Company agrees with and supports these principles and asks that the Commission apply them in selecting a revenue apportionment.

The Company respectfully disagrees, however, that a preference for the Department's view on how costs are measured through the CCOSS necessitates or supports adopting the Department's position on the role cost plays in apportioning

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[109] ALJ Report at ¶ 753.
[110] Ex. 102 (Peppin Direct) at 19; Ex. 103 (Peppin Rebuttal) at 41; Ex. 260 (Pollock Rebuttal) at 22-23; Ex. 345 (Maini Surrebuttal) at 19.
[111] ALJ Report at ¶¶ 758-777
[112] ALJ Report at ¶ 775.
[113] Ex. 105 (Huso Direct) at 6, 10; Ex. 107 (Huso Rebuttal) at 9; Ex. 420 (Peirce Direct) at 3.
[114] Ex. 25 (Sparby Direct) at 31; Ex. 26 (Sparby Rebuttal) at 7-9; Ex. 343 (Maini Direct) at 33. *See also* ALJ Report at ¶ 753 (acknowledging that keeping large customers on the system benefits all customers).

revenue.[115] Revenue apportionment involves "a careful balancing of many complementary and competing interests," including the extent to which rates should reflect cost.[116] The record in this case shows that improving the competitiveness of the Company's business rates is another interest worthy of consideration.[117] Continually asking business customers to pay larger and larger portions of the Company's total revenues ultimately harms all customers through decreased future sales that can produce a need for future rate increases.[118] Yet, as shown in the table below, adopting the Department's apportionment results in almost no change from the status quo in the percentage of the Company's total revenue paid by each class.

[115] ALJ Report at ¶ 775 ("Because the Administrative Law Judge has recommended that the Commission adopt what is largely the Department's proposed CCOSS methodology, the Administrative Law Judge concludes that the Department's proposed revenue apportionments for 2014 and 2015 should be adopted but modified for the Lighting Class in 2015.").
[116] *St. Paul Area Chamber of Commerce,* 251 N.W.2d at 354.
[117] Ex. 25 (Sparby Direct) at 31; Ex. 26 (Sparby Rebuttal) at 7-9; Ex. 343 (Maini Direct) at 30-34; Ex. 260 (Pollock Direct) at 39-40.
[118] Ex. 343 (Maini Direct) at 33.

Table 1
Comparison of Class Percentage of 2014 Total Revenue

2014				
Class	**Present Revenues**[119]	**Company Proposed**[120]	**Department Proposed**[121]	**ALJ**[122]
Residential	36.46%	36.70%	36.29%	36.49%
Non-Demand	3.85%	3.79%	3.68%	3.83%
C&I Demand	58.75%	58.62%	59.14%	58.77%
Lighting	0.94%	0.89%	0.89%	0.92%
2015				
Class	**Present Revenues**[123]	**Company Proposed**[124]	**Department Proposed**[125]	**ALJ**[126]
Residential	36.46%	36.74%	36.29%	36.46%
Non-Demand	3.85%	3.78%	3.68%	3.80%
C&I Demand	58.75%	58.61%	59.14%	58.75%
Lighting	0.94%	0.87%	0.89%	0.98%

Further, the Department's apportionment does not reflect any gradual improvement over time in the percentage of total revenue paid by business customers. The Company asks that the Commission modify the ALJ's recommended apportionment to help address the percentage of revenue paid by our business customers.

Parties have made the following recommendations of how to allocate the potential revenue increase in this case:

119 Company's January 16, 2015 Compliance Filing at Attachment K, page 9 of 10.
120 Ex. 107 (Huso Rebuttal) at 5.
121 Ex. 422 (Peirce Surrebuttal)Ex. 422 (Peirce Surrebuttal) at 8.
122 Company's January 16, 2015 Compliance Filing at Attachment K, page 9 of 10.
123 Company's January 16, 2015 Compliance Filing at Attachment K, page 9 of 10.
124 Ex. 107 (Huso Rebuttal) at 5.
125 Ex. 422 (Peirce Surrebuttal)Ex. 422 (Peirce Surrebuttal) at 9.
126 Company's January 16, 2015 Compliance Filing at Attachment K, page 9 of 10.

Table 2
Comparison of Recommended Apportionment of Proposed Revenue Increase[127]

2014					
Class	**Company**	**Department**	**OAG**	**MCC**	**XLI**
Residential	7.6%	6.4%	6.2%	10.1%	7.8%
Non-Demand	7.7%	4.8%	6.2%	7.8%	6.6%
C&I Demand	5.4%	6.3%	6.3%	4.2%	5.3%
Lighting	0.0%	0.0%	0.0%	-13.0%	0.0%
Total	6.2%	6.2%	6.2%	6.2%	6.2%
2015					
Class	**Company**	**Department**	**OAG**	**MCC**	**XLI**
Residential	11.3%	9.9%	9.7%	*	*
Non-Demand	11.2%	8.2%	9.7%	*	*
C&I Demand	8.9%	9.8%	9.9%	*	*
Lighting	0.0%	3.1%	1.6%	*	*
Total	9.7%	9.7%	9.7%	*	*

Under these recommendations, classes end up with revenue increases that may be higher or lower than the total increase, which is a reflection of both the recommended movement toward cost and each party's underlying view on the cost of service. As demonstrated above, however, adopting the Department's apportionment results in almost no change in the percentage of total revenues paid by each class. The Company therefore continues to support its recommended apportionment as a means of helping to address the competitiveness of its business rates.

As an alternative, the Commission could also consider an apportionment that blends the Company's recommendation and the Department's recommendation. This blended recommendation would result in the following apportionment of the revenue increase in this case.

[127] Ex. 107 (Huso Rebuttal) at 5, Tables 3 and 4; Ex. 422 (Peirce Surrebuttal)Ex. 422 (Peirce Surrebuttal) at 3-4, Tables 3 and 4; Ex. 375 (Nelson Direct) at 39, Tables 9 and 10; Ex. 378 (Nelson Surrebuttal) at 18; Ex. 343 (Maini Direct) at 20, Table 5; Ex. 345 (Maini Surrebuttal) at 20-21; Ex. 260 (Pollock Direct) at 46-47 (indicating XLI's proposed recommendation would move all classes to cost); Ex. 263 (Pollock Surrebuttal) at 31 and Schedule 22. Note, values for the OAG, MCC and XLI in the above table relate to the Company's proposed Rebuttal Testimony revenue requirement and were adjusted from Direct Testimony positions using the proportional adjustment methodology described on page 13 of Mr. Huso's Direct Testimony. The MCC and XLI did not provide specific allocations for 2015.

Table 3
Blended Apportionment of Proposed Revenue Increase[128]

2014		
Class	**Rebuttal Revenue Requirement**	**ALJ Report Revenue Requirement**
Residential	7.00%	2.85%
Non-Demand	6.26%	2.55%
C&I Demand	5.87%	2.39%
Lighting	0.00%	0.00%
Total	6.24%	2.54%
2015		
Class	**Rebuttal Revenue Requirement**	**ALJ Report Revenue Requirement**
Residential	10.60%	7.61%
Non-Demand	9.69%	6.96%
C&I Demand	9.35%	6.72%
Lighting	0.00%	0.00%
Total	9.73%	6.99%

Similar to the Company's primary recommendation, the figures above could be adjusted to reflect the final revenue requirement ordered by the Commission using the proportional factoring approach supported by the Company, Department and ALJ.[129]

Based on the above, the Company requests ALJ Report Finding 775 be amended as follows:

> 775. ~~Because the Administrative Law Judge has recommended that the Commission adopt what is largely the Department's proposed CCOSS methodology, the Administrative Law Judge concludes that the Department's~~ The Company's proposed revenue apportionments for 2014 and 2015 should be adopted. ~~but modified for the Lighting Class in 2015~~. The Company's ~~Department's~~ proposed revenue apportionments are reasonable because they ~~are closely aligned with the costs determined by the Department's CCOSS and also avoid rate shock.[1158] As such, they~~ properly balance the rate design principles of promoting efficient use of

[128] For 2015, the blended apportionment adopts the ALJ's recommendation to not increase Lighting class revenues in 2015. *See* ALJ Report at ¶ 776.
[129] Ex. 105 (Huso Direct) at 12-13; Ex. 420 (Peirce Direct) at 11; ALJ Report at ¶ 777.

resources, ~~and~~ ensuring that rate changes are gradual and the competitiveness of the Company's business rates.

The Company also asks that ALJ Report Finding 776 be deleted in its entirety.

C. Interruptible Rates[130]

The Company appreciates the ALJ's recognition that some increase in interruptible service discounts is necessary.[131] Interruptible load has decreased since the Company's last rate case.[132] In the face of such declines, taking action now should help the Company maintain an optimal supply of interruptible load.[133] The lower recommendation supported by the Department does not reflect the fact that the value of interruptible service stems from the option to interrupt, not necessarily the number of interruptions.[134] Further, the Department's recommendation is based on the current amount of interruptible load and does not account for the recent trends towards decreasing supply of interruptible load.[135] Given recent trends in the amount of interruptible load and the State's policy in favor of interruptible service,[136] the levels of interruptible rate discounts proposed by the Company are reasonable.

The Company therefore requests ALJ Report Finding 828 be amended as follows:

> 828. All parties agree that some increase in interruptible service discounts is necessary. Based on the evidence in the record, ~~the Administrative Law Judge concludes that~~ the Company's ~~Department's~~ proposal to increase the Level C Performance Factor interruptible service discounts by six ~~three~~ percent, and institute corresponding increases for the other performance factors to maintain the current relationship between tiers is the most reasonable. ~~The other parties have~~

130 ALJ Report at ¶¶ 817-828.
131 *See* ALJ Report at ¶ 828.
132 Ex. 345 (Maini Surrebuttal) at 24; Ex. 145 (Mani Opening Statement) at 1 and Attachment A (Company response to MCC-157).
133 Ex. 105 (Huso Direct) at 27.
134 Ex. 107 (Huso Rebuttal) at 35-36; Ex. 345 (Maini Surrebuttal) at 22; Ex. 263 (Pollock Surrebuttal) at 36.
135 Ex. 420 (Peirce Direct) at 26.
136 *See e.g.*, Minn. Stat. § 216B.05 ("Therefore, the legislature finds that it is in the public interest to… encourage those energy programs that will minimize the need for … additional electrical generating plants….").

~~failed to demonstrate that a larger increase is necessary to maintain an optimal supply of interruptible load.~~

D. Customer Charge[137]

The Company believes its proposed customer charges were reasonable and consistent with sound rate design objectives. We acknowledge, however, that the ALJ reached a different conclusion on this topic. The Company does not challenge the ALJ's overall recommendation regarding the customer charge, but does ask that the Commission either not adopt or modify several findings because they are not supported in the record. For example, the Company and Department have shown that low income customers exist across all usage levels, making a below-cost customer charge a questionable means of addressing affordability.[138] The ALJ also concluded the Company's minimum system study was reasonable to use in this case, mooting the OAG's cost-related arguments.[139] Finally, CEI's cost-based arguments against the Company's proposed customer charges were based on flawed calculations that inappropriately exclude customer-related costs and are contrary to industry guidance and Commission precedent.[140] Therefore, the Company requests ALJ Report Findings 812-814 be amended as follows:

> 812. The Company and the Department have both recommended increases to the Residential and Small General Service customer charges based on the Company's CCOSS results and previous Commission decisions that have endorsed moving the customer charge toward cost. In this case however, CEI and the OAG both have questioned the reasonableness of relying on the Company's CCOSS results as a proxy for fixed customer costs in determining the amount of the Residential and Small General Service customer charges. ~~While reference to the CCOSS analysis is appropriate for revenue apportionment purposes, CEI and the OAG have raised valid questions about whether the average~~

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137 ALJ Report at ¶¶ 778-816.
138 Ex. 105 (Huso Direct) at 18-21; Ex. 107 (Huso Rebuttal) at 31-33; Ex. 422 (Peirce Surrebuttal) at 4-5, 9-12.
139 ALJ Report at ¶ 745.
140 Ex. 103 (Peppin Rebuttal) at 36; Ex. 104 (Peppin Surrebuttal) at 2-4, Schedule 1.

> ~~customer costs calculated by the Company's CCOSS should be used in determining the fixed monthly customer charge. Consequently, the Administrative Law Judge finds it is appropriate to give less weight in this proceeding to the goal of moving the customer charges closer to cost as measured by the CCOSS results than in prior proceedings.~~
>
> 813. The record in this case also demonstrates that maintaining the Residential and Small General Service customer charges at their existing levels may ~~will~~ help to encourage conservation consistent with Minn. Stat. § 216B.03. ~~In addition, retaining the existing customer charges will promote affordability for low-use customers.~~
>
> 814. In this case~~, the view of the Administrative Law Judge,~~ the need to promote conservation ~~and affordability~~ outweighs the concerns of moving closer to the cost as measured by the Company's CCOSS results. This conclusion is buttressed by the fact that there have been a number of increases to the Company's customer charges in recent years.

V. RATE MODERATION

As part of this case, and to be responsive to our customers, the Company proposed a rate moderation mechanism that would result in more predictable and moderated rate increases. More specifically, the Company proposed to accelerate the amortization of the excess theoretical depreciation reserve for its Transmission, Distribution, and General (TD&G) assets in a pattern of 50 percent in 2014, 30 percent in 2015, and 20 percent in 2016 as well as to utilize the refunds received from the Department of Energy (DOE) to smooth the impact of its rate request to stable year-on-year increases for the two years of this MYRP as well as a third year for our then-expected 2016 request.

By way of background, the Company proposed its 50-30-20 amortization schedule based on the assumptions underlying our direct case. In other words, our initial rate moderation proposal was based on moderating our revenue deficiencies for the 2014 Test Year and 2015 Step Year as presented in our initial filing in November 2013. Over the course of this proceeding, the Company continued to defend its rate moderation proposal but recognized that other alternatives may provide our customers with greater value while preserving optionality for the future. For example, we presented a 50-0-50 (50 percent in 2015, 0 percent in 2015, and 50 percent in 2016) amortization schedule to demonstrate the impact of using and preserving half of the TD&G theoretical reserve.[141]

With the exception of using the DOE refund, the ALJ made no specific recommendation regarding which rate moderation tool should be used in this case. Instead, the ALJ noted that "[t]he determination of whether one or more rate moderation mechanisms should be adopted in this case will depend on the size of the revenue deficiencies for 2014 and the 2015 Step that result from the revenue requirement decisions made by the Commission in this proceeding."[142] We believe the ALJ appropriately deferred to the judgment of the Commission with respect to the appropriate amount and timing of any rate moderation that would be applicable in this case and into the future.

With respect to the use of DOE credits, we concur with the ALJ's recommendation that this pool of funds should be used for rate moderation purposes.[143] Although the ALJ made no recommendation with respect to the application of the DOE credits, the Company continues to advocate for the application of the DOE credits to moderate the rate increase for the 2015 Step.

As it pertains to the remaining rate moderation tools (TD&G excess theoretical, nuclear theoretical reserve and recovering the cost of the Grand Meadow and Pleasant Valley wind projects through the Renewable Energy Standard Rider), the Company believes it would be appropriate to use these tools in this case. We further believe the determination of which tool to use and how much of that tool to use depends on several factors: the Commission's determination of our revenue

[141]Ex. 97 (Robinson Rebuttal) at 16-17.
[142]ALJ Report at ¶ 630.
[143]ALJ Report at ¶ 631.

requirement for the 2014 Test Year and the 2015 Step Year; the Commission's decision regarding the Monticello prudence review; and the Commission's determination regarding our interim rate refund proposal. Depending on the outcome of these decisions the Commission may want to use more, or less, moderation today, which will also affect the availability of rate moderation tools for the future.

By way of example, and assuming the ALJ Report was adopted by the Commission, as well as our interim rate refund proposal, the Company believes there is a path which uses the 50-0-50 amortization schedule for TD&G theoretical reserve, and nuclear theoretical reserve, [144] that continues to provide predictable and moderate rate increases while allowing the Company and stakeholders the time and space to focus on the policy initiatives laid out in our December 22, 2014 letter supporting the e21 Initiative.

Likewise, it may be more reasonable and appropriate for the Commission to adopt the Company's initial rate moderation proposal, or some modified version of it. Depending on the resolution of the three factors mentioned above, the Commission could balance interests such that our customers experience further moderated rate increases for the 2014 Test Year and 2015 Step. We acknowledge the benefit of this outcome while noting the availability to use rate moderation tools in the immediate future will be limited to moderate revenue deficiencies on the immediate horizon.

We continue to believe the Commission is well positioned to make these policy determinations based on its ultimate revenue decisions in this proceeding.

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[144]As discussed in the ALJ Report and briefing, the Company did not support use of a nuclear theoretical reserve surplus in this proceeding due to uncertainty regarding the amount of any surplus due in large part to the more limited pool of nuclear assets, as compared to TD&G assets, with a more finite useful life. ALJ Report at ¶¶ 600-603. However, we also noted that more information about extending the assumed useful life of the Company's nuclear facilities for regulatory accounting purposes might warrant further review (ALJ Report at ¶ 603 (citing Ex. 94 (Perkett Rebuttal) at 11, 13-14)). This issue, like the TD&G rate moderation proposal, involves policy considerations which the Commission has the discretion to decide.

VI. OTHER REVENUE REQUIREMENT MATTERS

As noted earlier in these Exceptions, certain issues in this proceeding raise specific policy questions for the Commission, such as the Department's "Passage of Time" adjustment. In addition, the schedule in this proceeding does not contemplate replies to exceptions other Parties may offer. As a result, we provide limited comments below supporting the ALJ Report with respect to certain key issues in the proceeding.

A. Passage of Time

The Company is the first Minnesota utility to propose a MYRP, and we relied on the Commission's MYRP Order[145] in developing our MYRP proposal. More specifically, the structure of our MYRP proposal was based on the Commission's requirement that MYRPs be "designed to recover the cost of specific, clearly identified capital projects and, as appropriate non-capital costs…"[146] Therefore, our MYRP was based on a traditional test year for 2014 and a specific, limited capital (and directly related O&M) Step in 2015. The 2015 Step proposal included depreciation related to the specific limited capital projects included in the Step.[147] We believe that this structure is consistent with the Commission's guidance in its MYRP Order.

The Department proposed an adjustment to our 2015 Step request to account for the changes to accumulated depreciation reserve and expense due to the passage of time. The Department's proposed adjustment was intended to account for known and measurable changes to the entirety of the Company's rate base (not just those capital projects included in the 2015 Step) due to changes in depreciation from 2014 to 2015. Based on a Company response to a discovery request that only provided the

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[145] *In the Matter of the Minnesota Office of the Attorney General – Antitrust and Utilities Division's Petition for a Commission Investigation Regarding Criteria and Standards for Multiyear Rate Plans under Minn. Stat. § 216B.16, subd. 19*, ORDER ESTABLISHING TERMS, CONDITIONS, AND PROCEDURES FOR MULTIYEAR RATE PLANS, Docket No. E,g-999/M-12-587 (June 17, 2003) (MYRP Order).

[146] MYRP Order at p. 5.

[147] ALJ Report at ¶ 206 (citing Ex. 95 at 5, 7 (Robinson Direct); Xcel Initial Br. at 46).

change in accumulated depreciation, the Department calculated this adjustment to be a downward $17.5 million change to the Company's 2015 Step request.

The Company opposed this adjustment as both asymmetrical and inconsistent with the Commission's MYRP Order. The Company argued that the Department's proposed passage of time adjustment was asymmetrical because the $17.5 million adjustment only accounted for the increased accumulated depreciation for all of the Company's 2015 rate base without making the concomitant adjustment for the increase of depreciation expense for all of the Company's 2015 rate base, including all of the Company's 2014 capital additions. In other words, the Department's proposal only captured the downward adjustment related to accumulated depreciation without the related increases in depreciation expense that occurs from annualizing all of the Company's 2014 capital additions, not just those identified for inclusion in the 2015 Step. The record reflects that a symmetrical passage of time adjustment would result in an increase to our 2015 Step request of between $975,000 and $1.9 million, depending on how it is calculated.[148]

Similarly, the Company argued that the Department's proposed passage of time adjustment was inconsistent with the Commission's MYRP Order as it accounted for capital related costs that were not included in the Company's 2015 Step request. Because the Commission's MYRP Order directed that the out years of MYRPs should be based only on specific capital projects and their related O&M costs, the Company believed that it was inconsistent with this direction to make adjustments to its 2015 Step that were not directly related to capital projects included in the 2015 Step.

The Company was particularly concerned that the Department's proposed passage of time adjustment could make an MYRP unworkable. The Department's proposal to make adjustments to the out year of our MYRP based on known and measurable changes to the entirety of the Company's rate base significantly limited the

[148]ALJ Report at ¶ 218.

benefits of utilizing the MYRP construct if, as directed by the MYRP Order, the Company was unable to make adjustments to the second year of the MYRP to account for all changes in cost of service.[149] The Company offered that: "If the Department prefers to address cost decreases not tied to specific capital projects included in the Step, we believe it would be most appropriate to move forward with a fully-developed multi-year rate plan in which the Company's total revenue deficiency is potentially recoverable."[150]

The ALJ made two key findings with respect to the Department's proposed passage of time adjustment. First, the ALJ determined that Minnesota law "requires the Commission to consider both depreciation expense and change in rate base in determining whether the MYRP will result in just and reasonable rates."[151] Importantly, the ALJ's decision was based on her interpretation of Minnesota statutes and not in support of the Department's arguments related to fairness of a passage of time adjustment. Second, the ALJ found that "no downward adjustment to the Company's 2015 Step revenue requirement for the passage of time is necessary" as making a symmetrical calculation would result in an increase to the 2015 Step revenue requirement, which was not requested by the Company.[152]

The Company supports that ALJ's ultimate decision with respect to the financial impact of the Department's proposed passage of time adjustment to the Company's 2015 Step revenue requirement. It is undisputed on this record that the correct way to calculate the Passage of Time Adjustment requires consideration of both accumulated depreciation and depreciation expense. As the ALJ noted, when the calculation is performed correctly the resulting adjustment increases the Company's 2015 Step revenue requirement.

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[149]*See* Ex. 99 at p. 34 (Clark Rebuttal).
[150]*See* Ex. 99 at p. 34 (Clark Rebuttal).
[151]ALJ Report at ¶¶ 226-227 (citing to Minn. Stat. § 216B.16, subds. 6, 19).
[152]ALJ Report at ¶ 234.

The Company believes the ALJ Report also presents an opportunity for the Commission to alleviate tension between Minnesota statute, which suggests that a passage of time adjustment is necessary to ensure just and reasonable rates, and the Commission's direction that multi-year rate plans be limited to specific capital projects. If the MYRP Order allowed for recovery of our entire cost of service in each step year, we believe such tension could be alleviated. However, to the extent that MYRPs remain limited to specific capital projects while also requiring a passage of time adjustment, we believe that such tension will exist and the efficacy of this rate making tool could be limited. We therefore respectfully suggest that further discussion may be needed to determine whether a more comprehensive MYRP rate plan is appropriate, and would better account for changes to the utility's costs of service, including accumulated depreciation, depreciation expense, and other items, over time.

B. Qualified Pension Expense

We respectfully request that the Commission adopt the ALJ's Report with respect to ratemaking treatment of the Company's 2014 pension expense. We believe the ALJ Report properly builds upon the Commission's ratemaking decisions prior rate cases, and recognizes the Company's particularly robust data and evidentiary support for its pension expense in this proceeding.[153]

As in the Company's prior rate case, the Department challenged the Company's use of a discount rate calculated pursuant to Financial Accounting Standards (FAS) 87 for the Xcel Energy Services (XES) plan, rather than the Aggregate Cost Method (ACM) used for the older NSPM plan.[154] The Department

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[153]The ALJ Report reached conclusions with respect to Retiree Medical Expenses (FAS 106) – Discount Rate and 2008 Market Loss (2014) (Issues #6 and #19) that are consistent with and based upon the reasoning applied to the qualified pension issues. The Company concurs with this approach and outcome, and therefore does not separately address FAS 106 issues in these Exceptions.
[154]Department Initial Br. at 96.

argues that using FAS 87 for ratemaking purposes, and thereby calculating the discount rate on the basis of a bond-matching study performed as of December 31 of each year, would result in an artificially low rate based on one moment in time; would not match the Company's calculation of the discount rate under the NSP plan; and would not be equal to the Company's earned return on asset (EROA), as the different ACM method requires.[155]

In contrast to the last case, where the ALJ concluded that the Company did not adequately explain why our proposed discount rate should be used for ratemaking purposes, this ALJ Report notes that the Company provided extensive information regarding the reasonableness of our discount rate calculation.[156] In particular, through detailed Direct, Rebuttal, and the evidentiary hearing testimony the Company established that:

- The FAS 87 discount rate used for the XES plan is consistent with the discount rates used by utilities and other large companies;[157]
- The process for establishing the discount rate meets well-established criteria, including validation by reference to third-party benchmarks;[158]
- Utilizing the FAS 87 discount rate allows the Company to recover its undisputed actual expense;[159]
- Setting the discount rate for the XES plan equal to the EROA while using the FAS 87 method for financial accounting, as the Department suggests, would cause the Company to permanently under recover pension costs;[160]
- If the XES plan discount rate had been equal to the EROA since the plan's inception, customers would have paid more in pension expense over time

155 Department Initial Br. at 96-108.
156 ALJ Report at ¶¶124-125.
157 Ex. 83 (Schrubbe Rebuttal) at 41, 44-45.
158 Ex. 83 (Schrubbe Rebuttal) at 7.
159 Ex. 81 (Moeller Direct) at 86-87; Ex. 129 (Schrubbe Opening Statement).
160 *Id.*

because the service cost and interest cost elements of the FAS 87 calculation would have been higher;[161] and

- ERISA requires use of corporate bond yields, not EROA as the Department claimed, to establish the discount rate for pension funding.[162]

In addition to these considerations, the ALJ noted that the Commission declined to accept the Department's recommendation to use the EROA in the recent CenterPoint Energy rate case, and instead adopted a five-year average of actual discount rates.[163] The Company accepted this outcome as a reasonable compromise in this case, and the ALJ concluded that it presents a reasonable balance between the benefits of the Company's approach (noted above) and the range of actual discount rates the Company has experienced over the past five years.[164] We appreciate the ALJ's thorough review of the record and this balanced recommendation.

With respect to the 2008 market losses, in the Company's last rate case the ALJ recommended allowing the Company to continue phasing in and amortizing market gains and losses in the same manner utilized for several decades.[165] The Commission accepted this recommendation, but required the Company to provide additional information in this case establishing (i) that this method was consistent with the Company's historical accounting for pension gains and losses; and (ii) why shareholders should not bear a portion of pension costs, including market losses.[166]

The ALJ Report again recognized that the Company provided substantial information on these issues in this case, including the combined testimony of multiple Company witnesses.[167] There is no dispute that the Company's proposed treatment of the 2008 market losses follows long-standing practice. And although the

161 Ex. 81 (Moeller Direct) at 89; Ex. 129 (Schrubbe Opening Statement).
162 See 29 U.S.C. § 1083(h)(2)(C) (2012); Xcel Reply Br. at 54.
163 Ex. 129 (Schrubbe Opening Statement).
164 ALJ Report at ¶¶126-128.
165 Docket E002/GR-12-961 ALJ Report at 35-36.
166 Order in Docket E002/GR-12/961 at 51, 52.
167 ALJ Report at ¶ 148 (citing Ex. 81 (Moeller Direct) at 13-14, 20-21, 46-49, 55-64, 104-121 and Schedules 2 and 5; Ex. 78 (Figoli Direct) at 2, 70-73; Ex. 84 (Wickes Direct) at 2, 4-33; Ex. 126 (Schrubbe Opening Statement).

Department again argued that ratepayers should not bear all of the 2008 market losses and questioned whether the plan was too generous or could have been managed to achieve higher returns,[168] the Company explained why it is appropriate for pension costs, including gains and losses such as the 2008 market losses, to be included in rates. Specifically:

- This outcome is consistent with the ALJ's recommendation and Commission's decision in our most recent prior rate case;[169]
- The Company's retirement benefits, including qualified pension expense, are a legitimate cost of service and comparable to the Company's peers;[170]
- Including prior period gains and losses, including larger losses, is necessary to determine an accurate level of pension expense;
- Utilizing this method in the past (between 2000 and 2014 alone) benefited ratepayers through cumulative gains totaling $332 million, with qualified pension expense at or below zero between 2000 and 2011;[171]
- Neither shareholders nor Company employees benefit from market gains; rather, gains offset pension expense or are returned to the pension fund;[172]
- There is no record evidence that pension asset returns could have been higher;[173] and
- The 2008 market loss is not recovered solely in the short term, but rather phased in and amortized over time;[174]

Overall, the ALJ Report recommends allowing the Company to utilize its long-standing methods for calculation of the discount rate and accounting for the impact of market losses, each of which has benefited customers over the long term and

[168]Ex. 450 (Campbell Opening Statement) at 6.
[169]Order in Docket E002/GR-12/961 at 51, 52; Docket E002/GR-12-961 ALJ Report at 35-36.
[170]ALJ Report at ¶ 155 (citing Ex. 81 (Moeller Direct) at 56, 70-71; Ex. 78 (Figoli Direct) at 4-15, 24, 67-72.
[171]ALJ Report at ¶ 149 (citing Ex. 81 (Moeller Direct) at 60).
[172]ALJ Report at ¶¶ 153, 157.
[173]ALJ Report at ¶ 154.
[174]ALJ Report at ¶ 156.

enabled the Company to recover its actual pension expenses incurred to provide electric service to customers.[175] As a result, we respectfully submit that the ALJ's Report is based on the thorough record provided in this proceeding, a proper application of Commission precedent, and appropriate ratemaking considerations.

C. Paid Leave/Total Labor

The ALJ recommended rejection of the Department's proposed total labor adjustment.[176] The ALJ based her recommendation on the fact that the "Company provided detailed testimony supporting its test year amount, and demonstrated virtually all of the labor costs above the Department's" proposed adjustment have been fully justified.[177] Additionally, the ALJ determined that the "Department's suggestion that the Company should be limited to a three percent increase fails to consider the specific facts driving the 2014 test years expense."[178]

The Company supports the ALJ's recommendation. The Company provided a significant amount of information in its direct case that supported both the prudence of its 2014 cost of service as well as information identifying and discussing deviations in historical cost trends of its core business units. The ALJ's recommendation acknowledges this and relies on the Company's specific showings of the reasonableness of its 2014 labor costs on a core business unit basis. This is a reasoned outcome which results in just and reasonable rates based on the Company's 2014 cost of service.

D. Prairie Island Extended Power Uprate

In this case, the Company sought recovery of the costs incurred for the Prairie Island Extended Power Uprate (EPU) ($66.1 million plus accrued AFUDC of $12.8

[175]ALJ Report at ¶¶ 124-128, 146-158.
[176]ALJ Report at ¶ 199.
[177]ALJ Report at ¶¶ 192-196, 199.
[178]ALJ Report at ¶ 199.

million) before the project was terminated prospectively pursuant to Commission Order dated February 27, 2013.[179] No party other than the OAG and ICI questioned whether the project costs or AFUDC were prudently incurred or should be recovered.

The ALJ first addressed the threshold question whether project costs could be recovered if the project was never "used and useful." The ALJ concluded, consistent with Commission precedent, that the standard for cost recovery in relation to cancelled projects is whether the costs were prudently incurred in good faith.[180] We believe this to be the correct standard, and consistent not only with Commission precedent[181] but also with the public policy that utilities should be encouraged to consider canceling projects when doing so is in the public interest due to changed circumstances.[182]

The OAG also questioned whether the Company should be allowed to seek recovery of Prairie Island EPU costs in this proceeding, given that the costs were incurred in prior years. The ALJ noted that the Commission's Order in Docket E002/GR-12-961 expressly authorized the Company to seek recovery in this case, and properly rejected the OAG's argument.[183]

The OAG next argued that the Company did not prudently incur costs, speculating that the Company could or should have cancelled the project earlier and arguing in hindsight that the Company should have negotiated a different contract with Westinghouse. The ALJ Report recognizes that the contractual argument rests

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179 Docket No. E002/CN-08-510, Order Terminating Certificate of Need Prospectively (Feb. 27, 2013).

180 ALJ Report at ¶¶ 459-461.

181 *In the Matter of the Application of Interstate Power and Light Co. for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-001/GR-10-276, Findings of Fact, Conclusions, and Order at 33 (Aug. 12, 2011); *In the Matter of the Application of Otter Tail Power Co. for Authority to Increase Rates for Electric Utility Service in Minnesota,* Docket No. E002/GR-10-239, Findings of Fact Conclusions, and Order at 12 (Apr. 25, 2011);

182 In the Matter of the Application of Interstate Power and Light Co. for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E-001/GR-10-276, Findings of Fact, Conclusions, and Order at 33 (Aug. 12, 2011).

183 ALJ Report at ¶ 462 (citing the Commission's Order in the Company's most recent rate case at page 7). The ALJ also suggested that the OAG in part suggested recovery was not permitted in this proceeding because the Company "has not requested deferred accounting of its EPU Project costs." Id. This is not quite correct, as the Company requested deferred accounting in the Direct Testimony of Company witness Mr. Clark in case the Commission determined deferred accounting was needed. However, we believe deferred accounting was and is not necessary to the outcome of this issue.

"entirely on hindsight and is speculative" and noted that (i)the Company analyzed circumstances surrounding the project as they changed, and made appropriate decisions accordingly; (ii) minimized costs during the Company's continuing review of the Project; and (iii) sought Commission involvement when it appeared the Program should be suspended.[184] Thus the costs were prudently incurred and appropriately recoverable.

The OAG also argued that the Company should not recover AFUDC for the project on the grounds that the Company should have known the project was not viable in the third quarter of 2011, when the Company met with the NRC and learned the project would take longer and require more regulatory effort than initially expected. However, the ALJ again recognized that both the Company's and the Department's analyses in late 2011 through the second quarter of 2012 determined that the Project was still viable[185] and the project was managed appropriately.

Finally, the ALJ Report acknowledges that the OAG's proposal to bar the Company from recovering the 2012 pre-tax charge of $10.1 million misapprehends the nature of the charge. Rather than a write-off of actual project costs as the OAG contends, the pretax charge represents financial accounting uncertainty whether the Company might ultimately recover costs without earning a return on the asset.[186] Requiring a write-off of actual project costs would penalize the Company for taking appropriate financial accounting actions, and is not warranted.

With respect to amortization of project costs, the Company initially proposed recovering costs over 12 years with a return on the asset, or over six years with no return. Several parties proposed recovery over the life of the project with no return[187]

184ALJ Report at ¶¶ 463-464.
185ALJ Report at ¶ 465 (citing Ex 48 (Alders Direct) at 15-16, 18 and the Company's and Department's filings in the Prairie Island EPU Certificate of Need Changed Circumstances proceedings).
186ALJ Report at ¶ 466 (citing Ex. 47 (Weatherby Rebuttal) at 6; Tr. Vol. 1 at 182 (Weatherby)).
187ALJ Report at ¶¶ 454, 455, 457.

or with a 2.24 percent debt-only return.[188] The Company ultimately agreed to recovery over the life of the project with a debt-only return, which was likewise acceptable to the Department and the MCC. The ALJ Report found this outcome to be reasonable for both ratepayers and shareholders, as the period of recovery matches the remaining life of the facility while allowing a partial return in light of the length of the recovery period.[189] We believe this to be a reasonable outcome, and respectfully encourage adoption of the ALJ's recommendations with respect to the Prairie Island EPU.

E. CWIP/AFUDC

In the Company's last rate case, the Commission directed the Company to provide evidence in this case with respect to FERC accounting requirements for CWIP/AFUDC, whether the Company meets FERC accounting requirements, and whether a minimum level should be set for projects placed in CWIP.[190] The Company provided this information, establishing that the system of CWIP and AFUDC accounting it has used since 1977 is consistent with the FERC Uniform System of Accounts,[191] and with Minnesota Statutes striking an appropriate balance regarding treatment of CWIP.[192] The ALJ agreed, rejecting the OAG's contention that changes to the Company's long-standing accounting for CWIP and AFUDC are warranted.[193]

As a general matter, the OAG's proposed adjustments to CWIP and AFUDC accounting are inconsistent with FERC ratemaking principles, novel, and do not result in balanced accounting for these incurred costs. As an example, the OAG proposed excluding CWIP from rate base without proposing a corresponding removal of short-

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[188] ALJ Report at ¶¶ 456-457
[189] ALJ Report at ¶ 467.
[190] 12-961 Order at 54.
[191] FERC Uniform System of Accounts, Plant Instructions Section 3(17); FERC ORDER 561 (establishing the formula for AFUDC in 1977); Ex. 92, Perkett Direct at 54-55.
[192] Minn. Stat. § 216B.16, subds. 6 and 6a; Ex. 92, Perkett Direct at 54-56.
[193] ALJ Report at ¶ 542.

term debt from the Company's capital structure.[194] This approach fails to recognize the role of short-term debt in financing construction projects and is inconsistent with FERC principles; in addition, the OAG pointed to no jurisdiction that has adopted this approach.[195] Moreover, removing CWIP and the AFUDC offset, as well as removing short term debt from the capital structure, would in fact increase the 2014 revenue requirement alone by $8.5 million.[196]

The OAG also proposed setting the AFUDC rate at 2.62 percent (the average of the Company's short- and long-term debt rates), rather than in accordance with the FERC formula. This approach ignores that the Company utilizes both equity and debt to finance capital projects and that, as the OAG acknowledged, it is neither possible nor appropriate to attempt to trace overall funds to specific construction projects.[197]

Finally, the OAG's proposal to limit accrual of AFUDC to projects that exceed $25 million would deny the Company the ability to recover the very real financing costs for approximately 62 percent of Company projects.[198] While the OAG assumed the Company would use retail revenues rather than financing to cover the costs of such projects, this proposition fails to acknowledge that retail revenues are set to allow the Company to recover its costs of providing service – not to allow these revenues to be used in funding capital projects.[199] For these reasons and the others outlined in the ALJ Report, we believe the ALJ reached a reasoned outcome consistent with fundamental ratemaking principles, long-standing Commission precedent, and Minnesota statutes.

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[194] ALJ Report at ¶¶ 543-544.
[195] ALJ Report at ¶ 544.
[196] ALJ Report at ¶ 538.
[197] ALJ Report at ¶546.
[198] Ex. 94 (Perkett Rebuttal) at 29-30.
[199] ALJ Report at ¶ 545 (citing Ex. 94 (Perkett Rebuttal) at 31).

F. Other Disputed Revenue Requirement Issues

In addition to the key issues addressed elsewhere in these Exceptions and Clarifications, we respectfully request that the Commission adopt the ALJ's Recommendations on the following matters:

- *Rate Case and Monticello Prudence Review Expense Amortization (2014):* The ALJ concluded that costs of the Monticello LCM/EPU prudence review, like rate case expenses, should be amortized over two years because both types of costs are incurred to determine what expenses should be included in rates.[200] We believe this is the correct outcome, as neither type of cost benefits a plant in a manner that would justify amortizing the costs over the life of a facility.
- *In-Service Dates for Capital Projects (2014 and 2015 Step):* The ALJ accepted the Department's proposal to remove projects from the Company's initial proposed 2014 and 2015 rate base that would not be in service during the relevant year due to project delays, but also accepted the Company's proposal to offset this rate base decrease with projects that will now be in service during the relevant test year due to accelerated in-service dates.[201] We believe this is a reasonable approach, balancing the interests of the parties.
- *Return on Nuclear Refueling (2014):* The ALJ Report recommends rejection of the OAG's recommendation to disallow a carrying charge on deferred nuclear refueling costs.[202] The ALJs and Commission addressed this precise issue in the Company's 2010 and 2012 rate cases, and concluded that a carrying charge properly reflects the time value of money associated with deferring recovery of these costs.[203] There is no reason to revisit this analysis.

[200] ALJ Report at ¶ 479.
[201] ALJ Report at ¶¶ 496, 499-501.
[202] ALJ Report at ¶¶ 511-513.
[203] *I* ALJ Report at ¶¶ 511-513.

- *Nuclear Refueling Outage Costs – 2015 Step Treatment:* We believe the ALJ appropriately concluded that nuclear refueling outage costs are O&M expenses that are not subject to adjustment in a multi-year rate plan pursuant to the Commission's Multiyear Rate Plan Order.[204]
- *Corporate Aviation:* We believe the ALJ appropriately concluded that it is reasonable to include 50 percent of corporate aviation costs in the Company's revenue deficiency (consistent with Commission treatment of these costs in many other recent rate cases), that the Company provided the information required for this case; and that the OAG did not show that further adjustments to the total cost were warranted.[205]
- *Sherco Unit 3 Outage –Replacement Fuel Costs:* Because the issue of replacement power costs for Sherco 3 is already part of the AAA docket, the Company agrees with the Department and ALJ that related cost recovery issues are more properly addressed in the AAA docket than this rate case.[206]
- *Black Dog Unit 2 and 5 Outage Costs*: The ALJ rejected XLI's proposal to disallow the Company's costs of these outages because the costs were incurred prior to the test year and disallowance would constitute retroactive ratemaking.[207] We believe this is the appropriate conclusion, and further agree that any replacement power cost recovery issues should be addressed in the AAA docket.[208]
- *Pleasant Valley and Border Winds (2015 Step):* The ALJ concluded that either including these projects in 2015 base rates (the Department's preference) or instead moving cost recovery to the Renewable Energy Standards (RES) rider (acceptable to all parties) would be reasonable, and the outcome depends on

[204] ALJ Report at ¶¶520-522.
[205] ALJ Report at ¶¶ 558-563, 565-566.
[206] ALJ Report at ¶¶ 570, 572.
[207] ALJ Report at ¶ 578.
[208] ALJ Report at ¶¶ 578-579.

the Commission's preferences regarding use of the rider versus base rates.[209] We agree with this conclusion and also encourage the Commission to consider the impact of cost treatment on future rate cases, as discussed in the rate moderation segment of these Exceptions and Clarifications.

G. Key Resolved Issues

There are several revenue requirement issues that have been resolved between the Company and the Department. The Company appreciates the willingness of the Department to work to resolve these issues. The ALJ recommended that the Commission incorporate the agreements made by the parties in the course of this proceeding into its Order.[210] The Company supports the ALJ's recommendation.

There are two resolved issues that take advantage of the unique circumstances presented by this case. Specifically, the length of this case allows for the use of actual sales data to establish test year revenues, and actual property tax expense to establish property tax expense for the test year. By using actual data for sales and property taxes, final rates will include the most accurate information which is beneficial for our customers, especially considering the Company has proposed a MYRP.

With respect to the resolution of the sales forecast issue, the Company, the Department and MCC have agreed to utilize weather normalized sales data for the 2014 test year to set rates. This is possible because the Commission's ultimate deliberations on this rate case will occur after such sales have occurred and the data is available. This will "avoid the significant under-recovery of a forecast set too high, or an over-recovery if the forecast were set too low…"[211] The ALJ recommended that it is reasonable to adopt this proposal[212] and the Company agrees.

[209]ALJ Report at ¶ 586.
[210]ALJ Report at Recommendation 3.
[211]ALJ Report at ¶ 653.
[212]ALJ Report at ¶ 653.

With respect to the resolution of the property tax issue, the Company and the Department have agreed to true-up 2014 property tax with a hard cap of $145 million proposed by the Company. With this proposal, the Company's 2014 revenue requirement and the 2014 year-end property tax expense can be reflected in final rates in this case, up to a cap of $145 million.[213] The ALJ recommended that "[t]he resolution reached by the Company and the Department is reasonable and should be adopted."[214] The Company supports this recommendation.

VII. CONCLUSION

The Company respectfully recommends that the Commission adopt the ALJ Report with the changes described above.

Dated: January 20, 2015
Respectfully submitted by:
Northern States Power Company

[213]ALJ Report at ¶ 661.
[214]ALJ Report at ¶ 663.

CERTIFICATE OF SERVICE

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

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

xx by email; or

xx by electronic filing.

DOCKET NO. E002/GR-13-868

Dated this 20th day of January 2015

/s/
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