BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St Paul MN 55101-2147

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

MPUC Docket No. E002/GR-15-826
OAH Docket No. 19-2500-33074

DIRECT TESTIMONY OF NANCY A. CAMPBELL

ON BEHALF OF

**THE MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES**

FINANCIAL ISSUES

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PUBLIC DOCUMENT

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TABLE OF CONTENTS

I. INTRODUCTION

Q. Would you state your name, occupation and business address?

A. My name is Nancy A. Campbell. I am employed as a Public Utilities Financial Analyst by the Minnesota Department of Commerce, Division of Energy Resources (Department or DOC). My business address is 85 7th Place East, Suite 500, St. Paul, Minnesota 55101-2198.

Q. What is your educational and professional background?

A. I received a Bachelor of Science degree in Accounting with a minor in Business Administration in 1989 from Mankato State University (renamed Minnesota State University - Mankato). I also maintain an active Certified Public Accountant license in the state of Minnesota.

Q. What is your business experience?

A. My business background includes five years of experience with the Federal Energy Regulatory Commission (FERC) auditing electric and gas utilities. I also have over three years of experience performing accounting analysis and policy work for the FERC (including issues that came before the FERC on its agendas). Currently, I have worked for the Department for over 18 years as a Financial Analyst in the Energy Regulation and Planning Division.

As a Financial Analyst, I work on dockets with significant financial issues, including: rate cases, Minnesota Public Utilities Commission (Commission) and Department investigations, affiliated interest filings, purchase or sale of facilities filings, depreciation filings, and miscellaneous rate filings. I also monitor and participate in FERC issues, particularly issues involving the Midcontinent Independent System Operator, Inc. (MISO) and the Organization of MISO States (OMS) for the Department. For the period 2004 to 2006, I chaired the OMS Markets and Tariffs Workgroup.

For the period 2002 to 2005 and 2012 to 2014, I served as a member of the MISO Advisory Committee as a representative of the Public Consumer Group Sector. I have also been and continue to be an active member of the Public Consumer Group Sector.

II. PURPOSE

Q. What is the purpose of your testimony?

A. My responsibility, working in conjunction primarily with Department Witness Mr. Dale V. Lusti, is to review and investigate financial components of Northern States Power Company d/b/a Xcel Energy's (NSP, Xcel or the Company) application for a general rate increase. As outlined below, my testimony addresses a subset of the financial issues identified by the Department as a concern in this proceeding. The purpose of my testimony is to assist the Commission in evaluating the reasonableness of NSP's proposed revenue requirement to be used in establishing rates.

Q. How did you conduct your review in this proceeding?

A. In addition to my review of NSP's petition and pertinent documents, I issued written information requests and discussed with Company personnel various financial information and supporting documentation.

Q. Please describe NSP, in general.

A. NSP is a wholly owned subsidiary of Xcel Energy Inc. and is a Minnesota corporation. Xcel Energy Services Inc. (XES) is the service company for the Xcel Energy Inc., and thus provides services to NSP and other Xcel Energy Inc. subsidiaries. NSP has electric energy operations in Minnesota, Wisconsin, North Dakota and South Dakota.

Q. What is the scope of your Direct Testimony?

A. My Direct Testimony focuses only on certain financial areas of concern for which I recommend adjustments to NSP's rate-case petition. Specifically, the areas on which I focus my testimony and recommend adjustments or conditions are as follows:

- Depreciation Expense Adjustments Based on Approved Remaining Lives Study;
- Mankato Energy Center II In-Service Date;
- Protecting Americans from Tax Hikes Act of 2015;
- Accumulated Deferred Income Tax Pro-rate;
- State of Minnesota Research and Experimentation Tax Credits;
- North Dakota Investment Tax Credit;
- Energy Supply Operating and Maintenance (O&M) Expenses;
- Other Energy Supply O&M – Courtenay Wind;
- Nuclear Non-Outage O&M Expenses;
- Allocation – Transco Costs;
- Allocation – Service Company Costs;
- Health and Welfare and Benefits Expenses;
- 401 Nicollet Mall Building Lease;
- Non-Asset Based Trading;

- Prairie Island (PI) Settlement Payment;
- PI Fire Protection Program In-Service Date;
- Monticello Dry Fuel Storage (DFS) Load Cask No. 16, Increased Capital Costs;
- Spend Fuel Storage for Monticello;
- Spend Fuel for PI; and
- PI Capital Costs in Excess of Estimates Provided In 2008 CNS.

III. DEPRECIATION EXPENSE ADJUSTMENTS BASED ON APPROVED REMAINING LIVES STUDY

Q. According to the Company what was the status of the Company's 2015 Review of its Remaining Lives petition in Docket No. E,G002/D-15-46 when the Company filed its current rate case?

A. As noted by Xcel Witness Lisa Perkett, the Company submitted its 2015 Annual Remaining Lives petition on May 18, 2015. The Commission made its oral decision on October 22, 2015 in Docket No. E,G002/D-15-46, however no final Order had been issued at that time and according to the Company there was not enough time between the decision and the filing of the Company's rate case on November 2, 2015 to incorporate the Commission's decision to change the remaining lives for Sherco Unit 1, Angus Anson Units 2 and 3, and Granite City Units 1 through 4. As a result, the Company used its proposed position in its supplemental reply comments as the initial position in the current rate case.[1]

[1] NSP Ex. ___ at 29 (Perkett Direct).

Q. When did the Commission issue its Order in Docket No. E,G002/D-15-46?

A. On November 13, 2015 the Commission issued its Order Setting Depreciation Lives and Salvage Rates, Allowing Reallocation of Specific Depreciation Reserves, and Setting Effective Date (Commission's November 13, 2015 Order), which approved several changes in depreciation lives, salvage rates, reallocation of specific depreciation reserves with a January 1, 2016 effective date.[2]

Q. What changes approved by the Commission's November 13, 2015 Order were included in Company's initial rate case filing?

A. Ms. Perkett provided on pages 30 and 31 of her Direct Testimony the depreciation changes based on the Company's supplemental reply comments that were incorporated by the Company in its current rate case, and reflected in the Company's adjustment A-25.[3]

Q. What changes approved by the Commission in its November 13, 2015 Order were not included in the Company's initial rate case filing?

A. In Xcel's response to DOC information request no. 132[4] the Company indicated the following as the depreciation changes approved by the Commission that were not incorporated in the Company's initial rate case filing:

- change in remaining life of Angus Anson Units 2 & 3 from 3.8 years to 10 years;

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[2] See pages 6 and 7 of the Commission's November 13, 2015 Order in Docket No. E/G002/D-15-46.
[3] Volume 4B Test Year Workpaper Adjustments, Adjustment A25, Remaining Life Study NSPM.
[4] DOC Ex. ___ NAC-1 (Campbell Direct).

- change in remaining life of Granite City Units 1-4 from 3.4 years[5] to 8 years; and
- change in the remaining life of Sherco Unit 1 from 7 years to 10 years.

Q. What are the depreciation adjustments for the 2016 to 2020 test years, to reflect the changes in remaining lives depreciation approved by the Commission?

A. The Company provided this information in response to DOC information request no. 132, Attachment A. Specifically, the figures in Table 1 below list the 2016 to 2020 test year adjustments for depreciation expense and the Company's resulting revenue requirement adjustments, which include tax effects and the Company's proposed rate of return:

DOC Table 1: Depreciation Expense Adjustments for Approved RL Depreciation

($ in 000's)	2016	2017	2018	2019	2020
Depreciation Expense	($9,787)	($9,916)	($13,201)	($18,880)	($21,332)
Total Revenue Requirements	($8,046)	($7,618)	($9,777)	($13,727)	($14,703)

Q. Do you agree with the above depreciation expense adjustments?

A. Yes, the above depreciation expense adjustments for the 2016 to 2020 test years are reasonable to reflect the Commission's decision in its November 13, 20015 Order. However, I note that Department witness Dale Lusti calculates the Department's overall revenue requirements for all Department recommended adjustments. The Department's revenue requirements may be slightly different from the Company's revenue requirements shown above due to differences in

[5] Commission's November 13, 2015 Order says 3.3 years and Xcel initial depreciation filing said 3.3 years, so the Department believes the 3.4 years is in error.

assumptions, such as using the Department's proposed rate of return (instead of the Company's proposed rate of return).

IV. MANKATO ENERGY CENTER II IN-SERVICE DATE

Q. What is the Mankato Energy Center?

A. The Mankato Energy Center II (Mankato II) is a 345 MW natural-gas generator to be installed in Mankato and owned by Calpine Corporation. Xcel has power purchase agreement (PPA) that the Commission approved on February 5, 2015 in Docket No. E002/M-14-789 (Thermal Docket). This acquisition grew out of the Commission's decisions in Docket E002/12-1240, *In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need* (Competitive Resource Acquisition Docket).

Q. What date did the Company assume for recovering the capacity costs for the PPA?

A. According to page 135 of the Direct Testimony of Company witness Anne Heuer, the Mankato II contract was assumed to begin in 2018. Also Ms. Heuer's trade secret Schedule 13 showed the capacity costs by contract for 2016 to 2018, which included the Mankato II capacity costs by month.

Q. Was there another Xcel witness that addressed the Mankato II PPA?

A. Yes. Company witness Aakash Chandarana on pages 53 and 54 of his Direct Testimony addressed the in-service date for the Mankato II PPA. He stated that at the time the Company developed the rate case budgets and forecasts, the Company expected the Calpine Mankato generation unit would go into service in 2018. He also stated that since the capacity payments for the PPA are collected through base rates, the Company included the capacity costs in the 2018 Plan Year.

Q. Does the Company still expect Mankato II to be in-service by 2018?

A. No. According to Mr. Chandarana, in the summer of 2015, the Company and Calpine entered into a PPA amendment under which the commercial operation in-service date for the Mankato II was extended to 2019. He stated that this extension was done to preserve the Company's contractual rights while the North Dakota Commission determined whether it should provide the Company with an Advanced Determination of Prudence for the PPA costs. He also noted that, at the time of his direct testimony, the North Dakota regulatory proceeding was still on-going so it was difficult to speculate as to the plant's in-service date. As a result, he indicated that the Company reflected the capacity payments starting in 2018 with an understanding that the Company will updated the rate case once the situation becomes more certain.

Q. Did you ask the Company about its August 27, 2015 filing in its Competitive Resource Acquisition and Thermal Dockets?

A. Yes. I asked the Company to address page 6 of its August 27, 2015 filing in the Competitive Resource Acquisition and Thermal Dockets, specifically, the expected June 1, 2019 in-service date for Mankato II noted on page 6 of this filing.

Q. What was the Company's response?

A. In response to Department information request no. 130,[6] the Company provided the following:

> The commercial operation date as stated in the First Amendment to the PPA filed with the Commission August 27, 2015 in Docket Nos. E002/CN-12-1240 and E002/M-14-789 can be no later than June 1, 2019. Please see Trade Secret Attachment A to this response for a copy of the First Amendment to the PPA.

Q. When you reviewed Attachment A, what did you note on page 4 of 6?

A. Attachment A shows June 1, 2019 as the commercial operation date. Additionally there are some trade secret dates for milestone steps that need to be completed in 2018 and 2019 before the commercial operation date can be met. As a result, it seems clear that the expected in-service date is now June 1, 2019.

Q. Based on your review of the Mankato II PPA and the related capacity payments, what do you recommend for purposes of this rate case?

A. I recommend that the in-service date for Mankato II PPA and related capacity payments be changed from January 1, 2018 to June 1, 2019.

Q. What is the resulting adjustment for this rate case by changing the in-service date for Mankato II from January 1, 2018 to June 1, 2019?

A. In response to Department information request no. 131[7] on Attachment A, the Company provided the below adjustments for capacity costs due to the change in the Mankato II in-service date from January 1, 2018 to June 1, 2019. While I agree with the Company's adjustments for 2018 and 2019, the Company did not provide any

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[6] DOC Ex. ___ NAC-2 (Campbell Direct).
[7] DOC Ex. ___ at NAC-3 (Campbell Direct).

information to support its increase in capacity costs for 2020, and as a result, the Department assumed $0 impact for 2020, instead of $111,000 as noted by the Company. In other words, the Company has not demonstrated the reasonableness of its support for its proposed increase in capacity costs for 2020.

DOC Table 2: Mankato II Energy Center Adjustment Due to Change to In-Service Date

($ in 000's)	2016	2017	2018	2019	2020
Capacity Expense	$0	$0	($23,071)	($9,483)	$131
Xcel's Total Revenue Requirements	$0	$0	($19,411)	($7,979)	$111
DOC's Total Revenue Requirements	$0	$0	($19,411)	($7,979)	$0

V. PROTECTING AMERICANS FROM TAX HIKES (PATH) ACT OF 2015

Q. Did you ask the Company to calculate all tax updates due to the effect of the December 2015 tax legislation (2015 PATH Act), including the effect on all tax years for 2016 to 2020 (5-year rate plan)?

A. Yes. In information request no. 141[8], I asked for all tax updates due to the 2015 PATH Act, including the effect on all tax years for 2016 to 2020. In response to DOC information request no. 141, the Company referenced Xcel Large Industrial (XLI) information request no. 35, which provided the impacts for 2016 to 2018. The Company later provided a supplemental response to XLI information request no. 35,[9] which provided the impacts for 2019 and 2020.

[8] DOC Ex. ___ NAC-4 (Campbell Direct).
[9] DOC Ex. ___ NAC-5 (Campbell Direct).

Q. What tax changes did the Company address in its original and supplemental responses to XLI information request no. 35?

A. The Company addressed the following tax changes:

- bonus depreciation;
- wind production tax credits (PTCs);
- solar investment tax credits (ITCs);
- federal research and experimentation (R&E) credit; and
- impact on the Company's net operating loss (NOL).

Q. According to the Company what are the resulting tax adjustments and overall impact as a result of the 2015 PATH Act?

A. The Company provided on page 5 of the supplemental response to XLI information request no. 35, the below 2016 to 2020 tax adjustments and resulting overall impact:

Please see Attachments F and G to this response for bridge schedules that include all adjustments related to the PATH Act of 2015 for the 2019 and 2020 forecast years, respectively. Please note that the Bonus Tax Depreciation and Federal R&E Credit adjustments are shown in columns (2) and (3) of each page, but the impact of Secondary Calculations, especially the NOL calculation in column (6), are needed to fully illustrate the incremental impact.

$ millions	2016 Test Year	2017 Plan Year	2018 Plan Year	2019 Forecast	2020 Forecast	Total
Base Rate revenue requirement impact, cumulative	$(5.4)	$13.3	$4.7	$(9.2)	$(19.9)	
incremental	$(5.4)	$18.7	$(8.6)	$(13.9)	$(10.7)	$(19.9)

State of Minnesota, Electric Jurisdiction

The impact on the five year forecast is summarized below.

$ millions	2016 Test Year	2017 Plan Year	2018 Plan Year	2019 Forecast	2020 Forecast	Total
Burdick Sch. 13	$194.6	$246.7	$297.1	$379.6	$427.7	
PATH Act update	$(5.4)	$13.3	$4.7	$(9.2)	$(19.9)	
Updated cumulative forecast	$189.2	$260.0	$301.8	$370.4	$407.8	
incremental	$189.2	$70.8	$41.8	$68.6	$37.4	$407.8

State of Minnesota, Electric Jurisdiction

Q. Do you agree that the above reduction in taxes for 2016 to 2020 should be reflected in the five-year rate plan?

A. Yes. I recommend that the ($19.9) million overall reduction in taxes due to the 2015 PATH Act be reflected in the five-year rate plan.

VI. ACCUMULATED DEFERRED INCOME TAX (ADIT) PRO-RATED

Q. What are deferred taxes?

A. Company witness Lisa Perkett provided on page 50 of her Direct Testimony the following explanation for deferred taxes:

> Deferred taxes are a result of an accounting process called "normalization", which is the timing difference between book and tax accounting. The difference is

> then multiplied at the current tax rate to determine the current deferred tax. This amount in turn is added to the Accumulated Deferred Income Tax (ADIT) balance. Deferred taxes derive from tax depreciation being greater than book depreciation (in the early years of an assets life.) The Company's ADIT balance has been growing in large part due to bonus tax depreciation, discussed below. The Company strives to maximize the tax benefits by using accelerated methods to depreciate its assets, which are often taken in the early years of an asset's life. Deferred taxes, from a rate making perspective, allow the Company to share the early tax benefits with all customers equally over the asset's straight line book life.

Q. What is bonus tax depreciation and how does it affect the rate case revenue requirement?

A. Ms. Perkett provided on page 51 of her Direct Testimony the following explanation for bonus tax depreciation and how it affects a rate case revenue requirement:

> Like accelerated tax depreciation, bonus tax depreciation is a depreciation method used for income tax purposes that reflects more depreciation in the early years of an asset's useful life compared to straight-line depreciation. Straight-line depreciation is used for financial accounting and regulatory purposes and is the method on which gas and electric utility rates are set. Bonus depreciation defers income taxes by reducing taxable income in the early years of an asset's life and increasing taxable income in the latter years. The difference between straight-line depreciation (constant through an asset's life) and bonus depreciation is a matter of timing, which in turn generates a deferred tax liability (FERC Account 282, Accumulated Deferred Income Taxes – Other Property).
>
> Revenue requirement is impacted by bonus depreciation as a decrease to rate base when the bonus depreciation is factored into the ADIT calculation. The ADIT generated by bonus depreciation represents government-supplied funds to the utility and, consequently, requires the balance to be credited to rate base. Under normalized accounting for income taxes, ADIT signifies amounts

> paid by customers for current taxes that the utility will not have to pay the government until a later period.

Q. Do you agree with the Company's definition of deferred taxes and bonus tax depreciation and how it affects the rate case revenue requirements?

A. Generally yes; however, I do not agree that the ADIT generated by bonus depreciation or any accelerated tax method represents government-supplied funds to the utility. Rather, it is the ratepayer that has prepaid normalized deferred income taxes before the taxes are due. This fact is why ratepayers received an ADIT credit, which reduces rate base, because ratepayers have pre-paid the tax amount owed by the Company to the Internal Revenue Service (IRS).

Q. Who sets the rules for tax normalization and what are these rules?

A. Ms. Perkett discussed on pages 53 and 54 of her Direct Testimony that the Internal Revenue Code sets the standards for normalization and cites Internal Revenue Code Section 168(i)(9)(B)(i) as follows:

> [T]he taxpayer must, in computing its tax expense for purposes of establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, use a method of depreciation with respect to such property that is the same as, and a depreciation period for such property that is no shorter than, the method and period used to compute its depreciation expense for such purposes....[10]

Q. In past rate cases how has the Company calculated its ADIT balances?

A. Since at least 2005 and likely much earlier, the Company included non-prorated ADIT balances in its forecasted test-year rate base.

[10] 28 U.S.C.A. § 168(i)(9)(B)(i) (West 2015).

Q. Is the Company planning on changing how it calculates the forecasted test-year ADIT balance in this rate case (one of the three components of rate base noted above)?

A. Yes. On pages 54 to 56 of her Direct Testimony, Ms. Perkett discusses the private tax rulings and the effect on current ADIT balances. In simple terms, because Xcel is proposing a forecasted test year in this proceeding, the private letter rulings indicate that a utility must pro-rate the monthly incremental increases to the ADIT balance. As a result of this change, Xcel's test-year ADIT balance is reduced.

Q. **Does Xcel plan to true-up or replace its forecasted pro-rated ADIT balances with non-prorated ADIT balances in the following year when the balances are no longer forecasted and actuals are known?**

A. No.

Q. Has Congress changed the Tax Code to cause the Company to change its calculation for ADIT?

A. I am not aware of any such change, nor does Xcel cite any such change. Instead, Xcel bases its proposal on the IRS's private letter rulings issued to various companies, as discussed on pages 53 to 55 of the Direct Testimony of Ms. Perkett, that discuss ADIT, specifically the current portion[11] of ADIT for forecasted test periods.

[11] For ADIT there is an accumulated balance portion based on prior years and there current ADIT for forecasted costs for the current year.

Q. Why are you concerned that the Company is changing a long standing position on how it treats its ADIT balance for ratemaking purposes and using private tax rulings as support?

A. I am concerned because ratepayers are continuing to pay the same depreciation and related taxes on investment, and now ratepayers will not be receiving the full ADIT offset or credit to rate base.

Q. Do these private letter rulings even apply to Xcel?

A. No. At the end of all private letter rulings, the IRS provides the following statement, which basically says this IRS decision is only to be used by the entity requesting the decision:

> This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent.[12]

Q. Has the Federal Energy Regulatory Commission (FERC), which regulates wholesale electric rates, addressed this issue?

A. Yes. In Department information request no. 157[13] I asked to the Company to address FERC's December 2015 Order in Docket No. ER16-197, where FERC rejected NSP's Attachment O filing and required NSP to correct its ADIT true-up amount in its Attachment O filing. Basically, FERC allowed the pro-ration for current forecasted ADIT, but once the balances become historical (actual) amounts in the following year, NSP/Xcel was required to true-up to actual by using beginning-of-year

[12] See last page of Department information request no. 157, DOC Ex. ___ NAC-6 (Campbell Direct).
[13] DOC Ex. ___ NAC-6 (Campbell Direct).

and end-of-year ADIT amounts. FERC's approach is consistent with the language in the IRS private letter ruling, discussed below.

Q. What was Xcel's response to your information request?

A. The Company provided both an initial response and supplemental response to Department information request no. 157 which are both included to the supplemental response. Basically the Company mentioned that Ameren Illinois and NSP (which are MISO transmission owners) both raised concerns about FERC not accepting their Attachment O filing. Xcel noted in its FERC filing that Virginia Electric Power Company (which is a PJM transmission owner) was allowed not to true-up to actual ADIT amounts in the following year in Docket No. ER14-1831-001.

Q. How many MISO transmission owners are there and how many took the tax position that NSP took?

A. Based on MISO's website there are 24 MISO transmission owners and only two (NSP and Ameren) of the 24 transmission owners took what I believe is an aggressive tax position, while the other 22 transmission owners did not, and agreed to apply the ADIT true-up in the following year once balances become actual and are no longer "future."

Q. What is your basis for calling Xcel's proposal an "aggressive tax position"?

A. I have several reasons. First, as noted above, Xcel has not shown that the IRS private letter rulings apply to the Company. Second, even if the IRS private letter rulings applied to Xcel, the IRS language quoted below is clear that, once the test period is over, the need to prorate (make an adjustment to allow the utility to keep the benefits of accelerated depreciation for a limited time) is gone and the true-up does not need to be prorated.

Third, Xcel is one of the few transmission-owning utilities to take such a position at FERC, as discussed further below. Fourth, the other two utilities that took a similar position are in states that, at least at one time deregulated electric service; Xcel has not shown that, as a utility that has been and continues to be under fully regulated ratemaking, Xcel would be in a similar position. Fifth, Xcel has not shown any basis for the Company's position that Xcel is entitled to keep the benefits of accelerated depreciation permanently, rather than the long-standing treatment of accelerated depreciation only as a timing issue.

The language in the IRS private letter ruling is as follows:

> Congress was explicit: normalization "in no way diminishes whatever power the [utility regulatory] agency may have to require that the deferred taxes reserve be excluded from the base upon which the utility's permitted rate of return is calculated." H.R. Rep. No. 413, 91st Cong., 1st Sess. 133 (1969).
>
> …
>
> [T]he second interpretation of section 1.167(l)-1(h)(6)(ii) of the regulations [that "**the historical period is that portion of the test period before rates go into effect, while the portion of the test period after the effective date of the rate order is the future period**"] is consistent with the purpose of normalization, which is to preserve for regulated utilities the benefits of accelerated depreciation as a source of cost-free capital. The availability of this capital is ensured by prohibiting flow-through. But whether or not flow-through can even be accomplished by means of rate base exclusions depends primarily on whether, at the time rates become effective, the amounts originally projected to accrue to the deferred tax reserve have actually accrued.
>
> If rates go into effect before the end of the test period, and the rate base reduction is not prorated, the utility commission is denying a current return for accelerated

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

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

...

In contrast to the projections discussed above, **the true-up component is determined by reference to a purely historical period and there is no need to use the proration formula to calculate the differences between Taxpayer's projected ADFIT balance and the actual ADFIT balance during the period. In calculating the true-up, proration applies to the original projection amount but the actual amount added to the ADFIT over the test year is not modified by application of the proration formula.** (Emphasis added)[14]

Q. How many PJM transmission owners are there and how many took the aggressive tax position that NSP took?

[14] https://www.irs.gov/pub/irs-wd/201541010.pdf pages 6-8

A. According to the PJM website under current members, there are 13 voting transmission owners and I believe only one of these members, Virginia Electric Power Company, took the aggressive tax position that Xcel is taking.

Q. Are there other Minnesota electric utilities that are also MISO transmission owners like Xcel, who have agreed to apply the true-up as you propose?

A. Yes, both Minnesota Power and OtterTail Power filed their Attachment O at FERC with a pro-rated ADIT balance for current year forecasted amounts, but then agreed to true-up back to beginning and end-of-year balances the following year. As a result, this issue is really a timing issue (where the Company gets a one year temporary loan based on the current year ADIT balance) and not a permanent change in how ADIT is recovered for ratemaking.

Q. Do you agree with the Company's conclusion that they have to treat the ADIT amount the way they proposed in the current rate case to avoid a violation of tax normalization rules?

A. No. It appears that Ms. Perkett concludes that the private letter rulings are basically IRS regulations, but my understanding is that is not the case. As I noted above, the IRS states that private letter rulings are for the individual tax entity that requested the tax ruling, since the decision was made based on the facts in that particular case. Notably, it may not be reasonable to state that just because the IRS has concluded one way in certain private letter rulings (that are based on particular facts and are expressly not precedential) means that "the IRS has not disallowed" a certain method under different facts. Additionally, since a significant majority of MISO and

PJM transmission owners are taking the position that they should pro-rate the current ADIT forecasted amount but then do a true-up to non-prorated actuals based on beginning-of-year and end-of-year ADIT balances in the following year, I note that these other utilities do not seem to have a concern with the tax normalization violations that NSP is claiming. Moreover, even the IRP private letter ruling quoted above is clear that prorating is not applicable in the true-up.

Q. Do you believe that Congress should change the way ADIT amounts are flowed back to customers or that the IRS should change its interpretation or application of tax laws in that regard?

A. No. My understanding of the private letter rulings was a concern that for forecasted costs such as a forecasted test year, the ADIT credits for the current year forecast was being flowed back to customers too soon under the non-prorated ADIT method that has been used by NSP for ratemaking well before 2005. As a result, the prorated ADIT method was determined in a private letter ruling to address the concern about flowing back the tax benefits to ratepayers too soon.

However, looking at this issue from an equity perspective, current Minnesota electric utilities are not paying a significant amount of federal income taxes as a result of the tax legislation that has allowed significant amounts of bonus tax depreciation over one and two years, yet *ratepayers continue to pay the full amount of income taxes imputed with the assumption that someday the utility will have to pay the tax amount*.

In the past, ratepayers would receive the full offsetting ADIT balance or credit to rate base for this tax amount. Xcel is now proposing to reduce this offsetting ADIT balance or credit to rate base as well. Additionally, ratepayers are paying for the costs of these assets in rate base along with a return on plant investment while paying the full amount of deferred income tax expenses, but are now being denied the full offsetting ADIT balance or credit to rate base.

Q. Did you ask the Company to explain when it last paid federal income taxes?

A. Yes. In response to Department information request no. 1168,[15] the Company noted that Xcel Energy on a consolidated tax basis last paid material federal income taxes in 2008 of approximately $22.3 million. Since 2008, Xcel Energy has paid very small amounts of federal income taxes totaling less than $1 million in total for the period 2009 to 2015. Yet I note ratepayers are paying millions of dollars in income taxes in rates just based on the tax gross up of the revenue requirement in current and past rate cases.

Q. Have you seen any information from larger accounting firms that address the ADIT pro-rate and true-up tax issues?

A. Yes. Pricewaterhouse Coopers indicated in its "Tax Insights from US Power & Utilities"[16] that basically the IRS is giving utilities the use of an ADIT interest-free loan *for one year* and then they will need to refund according to FERC requirements, which require a true-up to actual historical ADIT balances as reported on the utilities FERC Form 1 (financial accounting information submitted to FERC by electric utilities).

[15] DOC Ex. ___ NAC-7 (Campbell Direct).
[16] DOC Ex. ___ NAC-8 (Campbell Direct).

Q. Did you ask the Company to provide the adjustments for both the 3-year and 5-year rate plans to replace the pro-rated ADIT balances with the non-pro-rated ADIT balances (using beginning and end-of-year balances) once ADIT balances become actual in the following year (basically the second part of the ADIT change for the true-up to actual)?

A. Yes I did, in Department information request no. 1139.[17] Unfortunately, the Company did not provide the ADIT adjustments to actual via true-up that I requested; instead it simply provided the same calculations shown on Company adjustment A-38, which reflects both ADIT changes (pro-ration of ADIT for current year forecast and not doing the true-up to ADIT actual amounts in the following year).

Q. What was the impact of the two ADIT Prorate changes made by Company in this rate case?

A. The below table provides the ADIT revenue requirement impacts for 2016 to 2020 as shown in adjustment A-38 on page A38-6:

DOC Table 3: Summary of ADIT Prorate Adjustment by the Company in Revenue Requirements

ADIT Adj A38 ($ in 000's)	2016	2017	2018	2019	2020
Requested ROE	$6,483	$1,896	$1,813	$1,357	($0,207)

Q. What recommendations do you offer based on your review of the ADIT issue?

A. I recommend the following regarding the prorated ADIT issue:

[17] DOC Ex. ___ NAC-9 (Campbell Direct).

- First, if Xcel continues to contest this issue, I recommend that the Company be required to get its own IRS private tax ruling before any change to ADIT is allowed for ratemaking purposes that will harm ratepayers;
- Second, the Commission could consider whether allowing forecasted test years continues to be reasonable when related benefits such as ADIT are not being provided to ratepayers in a consistent manner. In other words, ratepayers continue to pay 100 percent of the deferred taxes while receiving only a prorated ADIT offset to rate base;
- Third, at a minimum, the Commission should limit the use of a prorated ADIT balance for the current forecasted test year but require a true-up to actual or non-prorated ADIT balances the following year (consistent with the majority of MISO and PJM transmission owners, consistent with the FERC's recommendation in Docket No. ER16-197 and consistent with Pricewaterhouse Coopers article on "Tax Insights from US Power & Utilities");
- Fourth, since Xcel's proposed ADIT changes will harm ratepayers and change the way ratemaking is handling accelerated depreciation for rate cases without demonstrating adequate support to show that the ADIT change is required under the Internal Revenue Code or Treasury Regulations (only supported by private letter rulings that are entity specific), because Xcel failed to meet its burden of proof to show its proposed change to be reasonable, and because the Company failed to provide the adjustment the Department requested for the ADIT issue as

discussed above, I recommend that no ADIT changes be allowed in this rate case at this time.

VII. STATE RESEARCH AND EXPERIMENTATION TAX CREDITS

Q. Did you ask the Company to provide support for their Minnesota Research and Experimentation (R&E) Tax Credits for the 2016 to 2020 test years?

A. Yes. In Department information request no. 159[18] I asked the Company to address the Minnesota R&E Tax Credits the Company included in its 2016 to 2020 test years. In Attachment A to Department information request no. 159, the Company stated that the average of the 2011 to 2013 actual Minnesota R&E credits of $559,000 was used to determine the amount included in the test years for 2016 to 2020.

Q. Did you ask the Company to update its Minnesota R&E Tax Credits calculated on Department information request no. 159 Attachment A with 2014 and 2015 actuals?

A. Yes. In the Company's **revised** response to Department information request no. 2125, the Company explained that 2014 actuals were available but 2015 actuals would not be available until filed in September 2016. The Company provided in Attachment B an update for its Minnesota R&E Tax Credits based on 2012 to 2014 actuals of $492,000.[19]

[18] DOC Ex. ___ NAC-10 (Campbell Direct).
[19] DOC Ex. ___ NAC-11 (Campbell Direct).

Q. Based on your review of the Company's calculation of the 2012 to 2014 average for Minnesota R&E Tax Credit, has the Company demonstrated the reasonableness of its calculations?

A. No. The Company made two adjustments that I do not agree with based on my review. First, the Company made a **[TRADE SECRET DATA HAS BEEN EXCISED]** downward adjustment and stated in a footnote that, "Due to extraordinary project spend in 2013 with large value, non-recurring projects, the 2013 credit amount which was used in the average was adjusted." Since the Company is using a three-year average of 2012 to 2014 actual amounts to determine the Minnesota R&E Tax Credits for 2016 to 2020 test years, it is not appropriate to make adjustments to the actual amounts.

Second, the Company made adjustments to the Minnesota R&E Tax Credits 2012 to 2014 average called "Net Federal" which they haven't supported. Moreover, I didn't see any adjustment for federal related taxes on their Minnesota tax forms included as Attachment C to support this adjustment.[20]

Q. As a result, do you recommend an adjustment for Minnesota R&E Tax Credits for 2016 to 2020 test years?

A. Yes I do. I recommend that the Minnesota R&E Tax Credits for 2016 to 2020 be calculated based on the average of the actual Minnesota R&E Tax Credits for 2012

[20] See Company's revised response to Department information request no. 2125. DOC Ex. ___ at NAC-11 (Campbell Direct). Note that the Department had the Company revise this response because Xcel had incorrectly marked Trade Secret information by including historical averages that should have been public. The Department recommends that the Company review its policy for marking Trade Secret data in an effort to avoid incorrect use of the Trade Secret designation.

to 2014 as shown on their Minnesota tax form in Attachment C, without the Company's unsupported adjustments discussed above.

As a result I recommend that the Minnesota R&E adjustment be set at the average 2012 to 2014 unadjusted actual amounts provided on the Minnesota tax forms of $828,290 instead of the Company's recommended $559,000 based on 2011 to 2013 actuals with adjustments. The resulting adjustment is the difference between the Department's recommended $828,290 and Company's recommended average Minnesota R&E Tax Credits of $559,000 included in the test year, or an increase in Minnesota R&E Tax Credits of $269,290 for 2016 to 2020 test years.

Q. Are there any other adjustments that may need to be made?

A. Yes. I discuss below that 73.5% of the North Dakota Investment Tax Credit should be assigned to the Minnesota jurisdiction. If the Commission approves this recommendation, I generally conclude that the Minnesota R& E tax credit should also be assigned based on the 73.5% instead of 100%, although I note that there is also a North Dakota R&E tax credit that the Company needs to address as discussed below.

As a result, assuming that the Commission approves my recommendation below that 73.5% of the North Dakota Investment Tax Credit should be assigned the Minnesota jurisdiction, my above adjustment would be reduced to $197,928 ($269,290 * 73.5%).

VIII. NORTH DAKOTA INVESTMENT TAX CREDIT

Q. According to the Company, why should the North Dakota Investment Tax Credit (NDITC) only be directly assigned to North Dakota and not to Minnesota?

A. Company witness Anne Heuer began her discussion on pages 135 to 137 of her Direct Testimony, but titled the issue as "North Dakota Income Tax Credits." As background she noted that in Docket No. E002/M-15-401, the Company was instructed to discuss non-Minnesota state tax credits:

> The Company shall include in the initial filing in its next rate case both testimony and schedules disclosing, in detail and by project, all North Dakota Investment Tax Credits and all other non-Minnesota state tax credits earned or held by the Company as a result of its investments and activity.

Xcel Ex. ___ at 135 (Heuer Direct).

Q. What did you note based on the above information?

A. I note that the Company refers to the tax credits as "North Dakota *Income* Tax Credits" while the Commission's Order referenced "North Dakota *Investment* Tax Credits." This distinction is important because the goal of the North Dakota Investment Tax Credit (NDITC) was to incentivize the building of electric generation in North Dakota.

Q. According to the Company, why does Xcel believe that no NDITC or other non-Minnesota state tax credits should be applied to the Minnesota jurisdiction?

A. According to Ms. Heuer on page 136 of her Direct Testimony, the main reason for Xcel's proposed treatment is that income taxes (state and Federal) for jurisdictional cost of service are calculated on a stand-alone basis by applying the state-specific and Federal defined deductions and credits to the calculation of current taxes. She noted that, for example, with respect to deductions for the computation of state taxable income, one State may adopt the Federal Bonus provision and another state may not. She also noted Minnesota R&E credit is assigned 100% to Minnesota.

Q. What did Ms. Heuer state regarding North Dakota taxes?

A. Ms. Heuer on pages 136 and 137 of her Direct noted that North Dakota provides a state tax credit for wind development that is applied to North Dakota state taxes. She noted that by applying the Company's stand-alone logic, Minnesota ratepayers are not being asked to pay North Dakota state income taxes and North Dakota ratepayers are not be asked to pay Minnesota state income taxes.

Q. According to Ms. Heuer, what is the only non-Minnesota credit used by NSPM?

A. Ms. Heuer noted on pages 136 and 137 of her Direct Testimony that the North Dakota state credit for North Dakota wind generation is the only non-Minnesota state credit used by NSPM. Ms. Heuer also noted that the only project subject to the North Dakota wind credits is the Border Winds project, which went into service in December 2015.

Q. Did the Company address the North Dakota R&E tax credits?

A. No. Thus I recommend that the Company provide this information in its Rebuttal Testimony. I am concerned that the Company is arguing that, because Minnesota receives 100% of the Minnesota R&E credits and North Dakota gets 100% of the North Dakota ITC credits, Minnesota is better off (at least for this rate case). Unfortunately, the Company did not discuss the North Dakota ITC credits and other North Dakota taxes that Minnesota ratepayers pay as discussed below.

Q. Does Ms. Heuer provide an estimate of the North Dakota tax credits and compare them to Minnesota R&E credits?

A. Yes. On her Table 10 and in the narrative discussion on page 137 of her Direct Testimony, she provided the following estimates for NDITC and compared it with Minnesota R&E tax credits, as follows:

	Revenue Requirements For ND – ND ITC	Revenue Requirements For MN – MN R&E tax credit
2015	$0	
2016	$58,749	$559,000
2017	$612,677	$559,000
2018	$612,677	$559,000

Q. What does Ms. Heuer conclude based on the above tax credit information?

A. Basically, she concludes that by using the Company's stand-alone tax logic, where each state keeps its own tax credits, Minnesota ratepayers are better off (in this rate case) based on the above estimated information.

Q. When you reviewed tax information used for the current rate case, what did you notice about how taxes were calculated for financial statement purposes?

A. Based on my review of the tax information included in the rate case in Volume 3 Required Information, II Required Financial Information, C-1 and C-5, I note that the Income Statement used separated federal and Minnesota state tax rates. However, for Rate Base purposes, the Accumulated Deferred Income Taxes are calculated using the 40.8097% composite tax rate of Federal, Minnesota, and North Dakota, as shown in in Volume 4a, Test Year Workpapers Base Data, V.O&M, 05. State & Federal Income Taxes.

So, based on this information Xcel's rate case is mismatched: the income statement uses separate federal and MN state taxes, but rate base taxes are done on a consolidated or composite tax basis of federal/MN/ND. The Company's responses to these tax rates is found in response to Department information request no. 188.[21]

Q. When you asked the Company to provide all the North Dakota taxes by tax type included in the test year, what did you discover?

A. As shown in response to Department information request no. 1141 parts a & b,[22] the following are all the North Dakota taxes and how they are treated for rate case purposes:

[21] DOC Ex. ___ NAC-12 (Campbell Direct).
[22] DOC Ex. ___ NAC-13 (Campbell Direct).

	Included In MN COSS	Method	Cost Causative Allocation or Assignment Basis	Rational for Cost Causative Basis
System Related Shared Taxes ND Taxes/Tax Credits Included In Test Year				
ND Property Tax	Yes	Allocated	Production & Transmission Plant Investment	Tax based on Production & Transmission Property
ND Payroll Tax	Yes	Allocated	Labor-related	Follows the assignment or allocation of labor
ND Sales Tax	Yes	Allocated	Recorded with O&M or Capital cost	Follows the assignment or allocation of underlying cost
ND Deferred Income Tax	Yes	Allocated	Underlying Investment in Plant & Other Rate Base	Follows the assignment of Production & Transmission Property or Nature of Other Rate Base Item
Current Income Taxes and Related Credits ND Taxes/Tax Credits NOT Included In Test Year				
ND Current Income Tax	No	COSS Calculation	Tax Rates Based on ND State Law	Stand-Alone COSS tax methodology based on ND Taxable Income, net of Tax Credits
ND Investment Tax Credit	No	Direct ND	ND State Tax Law	Credit to ND Current Income Tax

Attachment A to this response provides revenue requirements by tax type included in the Minnesota COSS for the 2016 Test Year and the 2017 and 2018 Plan Years. Additional discussion of Attachment A is provided in response to part c) below.

Q. Based on your review of the above table, which North Dakota taxes are being paid by Minnesota ratepayers and which ones are not being paid by Minnesota ratepayers?

A. Minnesota ratepayers pay the following North Dakota taxes under Xcel's proposed ratemaking:

- property taxes (which is found on the income statement);
- payroll taxes (which is found on the income statement); and
- deferred and accumulated deferred income taxes (which are found on the rate base statement).

Minnesota ratepayers do not pay or do not receive the following North Dakota taxes:

- Income taxes (which is found on the income statement); and
- Investment Tax Credits (which is found on the income statement).

Q. Based on your review above, has the Company demonstrated the reasonableness of its assignment and allocation of taxes in this rate case?

A. No. Although the Company says it is allocating taxes on a stand-alone state tax basis, the reality is the Company is using a consolidated/blended tax rate of federal/MN/ND for rate base purposes, and is picking and choosing which North Dakota taxes are being paid by or credited to Minnesota ratepayers on the income statement. Additionally, the Company did not address how they are assigning North Dakota R&E tax credits, but I suspect it is being assigned to North Dakota.

Q. Did you ask the Company to assign the Minnesota jurisdictional amount of NDITC consistent with the assignment North Dakota wind facilities assigned to Minnesota?

A. Yes. In response to Department information request no. 1140 part a,[23] the Company stated in Attachment A that Minnesota would be allocated starting in 2020 ($737,119) in NDITC assuming 73.5% Minnesota jurisdictional allocator. According to the Company, it would not be able to use NDITC until 2020, due the 2015 Path Act (discussed further above).

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[23] DOC Ex. ___ NAC-14 (Campbell Direct).

The Company also stated in Attachment A that MN would be assigned ($455,433) in MN R&E tax credits assuming the same 73.5% Minnesota jurisdictional allocator for all test years 2016 to 2020.[24]

Q. Has the Company changed its position from past rate cases and other dockets on the assignment of NDITC to the Minnesota jurisdiction?

A. Yes. For the Merricourt wind project (before it was cancelled) and for the Wind 2 Battery project, the Company did assign to Minnesota its jurisdictional amount of the NDITC. Please see the Department comments in the RES Rider Docket No. E002/M-15-805 where the Department discusses why NDITC should be assigned to Minnesota ratepayers on a jurisdictional basis and references the two case where the Company provided the NDITC.

Q. Has the Department challenged another utility's treatment of NDITC?

A. Yes. The Department has also filed extensive comments in Docket No. E015/M-14-962 explaining that since Minnesota ratepayers pay for the wind facilities owned by Minnesota Power, Minnesota ratepayers should receive the ND ITC related to the wind facilities.

Additionally, Otter Tail Power in its last rate case (Docket No. E017/GR-10-239, current rate case, and in its past RES Riders, has correctly reduced wind facilities costs with the NDITC on a Minnesota jurisdictional basis.

Q. What do you recommend based on your review of taxes and specifically NDITC?

[24] DOC Ex. ___ NAC-14 (Campbell Direct).

A. For consistency and easy of application, I recommend that all taxes be assigned to Minnesota jurisdiction based on the 73.5% allocator which is used to assign all generation and transmission plant to Minnesota. In other words since Minnesota ratepayers pay for generation and transmission plant using a consolidated 73.5% allocator, all taxes should also be assigned to Minnesota jurisdiction using the same 73.5% in order to be equitable. This recommendation for taxes would avoid the picking and choosing by the Company for which tax is assigned to Minnesota. This means that NDITC, ND R&E (which the Company needs to address) and MN R&E would be assigned to Minnesota using the 73.5% allocator.

Q. What is your financial adjustment based on your recommend for ND ITC?

A. At a minimum, I would recommend a ($737,119) reduction for 2020 for the NDITC assigned to Minnesota jurisdiction. Because of some the uncertainty of tax amounts, a true-up for the NDITC in the RES Rider, like the Company does for the Production Tax Credit true-up may be appropriate.

Additionally, the Company should provide the ND R&E credit amounts on a Total Company and Minnesota Jurisdictional basis for 2016 to 2020 test years. The Company should also provide all calculations to show the impact of my recommendation that all taxes (expenses and credits) should be assigned to Minnesota using a 73.5% jurisdictional allocator.

IX. ENERGY SUPPLY OPERATING AND MAINTENANCE (O&M) EXPENSES

Q. What Company witness testified to Energy Supply O&M Expenses?

A. Company witness Steven Mills discussed Energy Supply and specifically, on pages 68 to 106 of his Direct Testimony he discussed Energy Supply O&M for 2016 to 2018.

Q. Did Mr. Mills explain how Energy Supply O&M is addressed in this rate case?

A. Yes. First, he discussed the 2016 Energy Supply O&M budget and the drivers of that budget. Then on pages 103 to 104 of this Direct Testimony he noted the 2017 and 2018 budget for Energy Supply O&M overall approach is addressed by Company witnesses Charles Burdick and John Mothersole for the escalation factor used for 2017 and 2018. Mr. Mills also explained that while the Company proposes to use escalation factors, there are specific drives that he identified that will impact the expense levels in 2017 and 2018 for Energy Supply O&M expenses.

Q. What is the Company's overall 2016 to 2018 Energy Supply O&M request?

A. Mr. Mills provides on page 69 of his Direct Testimony that the Company has budgeted $164.6 million in O&M expenses for 2016, which he stated is a 3.85% increase from the Company's 2015 forecast ($158.5) on a total company basis. Mr. Mills also provided in his Schedule 2, the O&M expenses on a total company and Minnesota Jurisdictional basis for the following:

- 2012 to 2014 actuals;
- 2013 and 2014 budget;
- 2015 forecast; and
- 2016 budget (Company requested amount).

Q. Did you ask the Company to include some additional information into Mr. Mills Schedule 2?

A. Yes. In Department information request no. 198 part c[25], I asked the Company to add the following additional information to Mr. Mills Schedule 2:

- 2015 actuals;
- 2017 and 2018 budget/test years; and
- O&M expense levels approved in last two years.

Q. Based on your review of the Company's response to Department information request no. 198 part c, what did you notice?

A. I noticed that the **Energy Supply O&M** 2015 actual expenses were only $151.1 million, which is $7.4 million lower than the Company's 2015 forecast of $158.5 million. This means when comparing 2015 actual amount of $151.1 million to 2016 test year amount of $164.6 million, the actual increase is 8.9%, not the 3.85% increase estimated by the Company. Additionally, I noted that Energy Supply O&M expenses are not showing a trend of increasing over time but instead have been up and down for 2012 to 2015 actual costs, as shown in the table below:

DOC Table 4: Energy Supply O&M Costs for 2012-2015 & 2012-2015 Average

($ millions)	2012	2013	2014	2015	2012-2015 average
Total Company	$153.0	$162.1	$157.0	$151.1	$155.8
MN Jurisdictional	$113.8	$120.0	$116.2	$111.5	$115.375

Q. In past rate cases, when costs are up and down, and not trending up or down, what has the Department recommended and the Commission approved?

[25] DOC Ex. ___ NAC-15 (Campbell Direct).

A. When actual costs are up and down the Department has recommended and the Commission has approved an average of actual costs for setting rates, such as the 2012 to 20115 four-year average provided in the above table.

Q. How does the 2012 to 2015 four-year average compare to the budgeted or requested 2016 to 2018 O&M cost levels?

A. As noted in the below table the 2012 to 2015 four-year average is $5.525 million higher than 2016 test year amount on a Minnesota Jurisdictional basis:

DOC Table 5: Four-Year Average Compared to 2016 to 2018 Test Years

($ in millions)	2012-2015 average	2016 TY	2017 TY	2018 TY
Total Company	$155.8	$164.6[26]	$168.7	$172.7
MN Jurisdictional	$115.375	$120.9	$123.9	$126.9

Q. What is the Company's five year O&M budget/requested test year amounts and how does that compare to the 2012-2015 four-year average?

A. According to Mr. Burdick's Schedule 13, the 2016 to 2020 or 5-year request for Energy Supply O&M costs is as follows:

DOC Table 6: Four-Year Average Compared to 2016 to 2010 Test Years

($ in millions)	2016TY	2017TY	2018TY	2019TY	2020TY	2012-2015 average
Total Company	$164.6	$168.7	$172.7	$170.7	$175.6	$155.8
MN Jurisdictional[27]	$120.9	$123.9	$126.8	$125.4	$129.0	$115.375

[26] See Charles Burdick's Schedule 13 for 2016 to 2020 test year total company amounts and assumed a 73.45% Minnesota jurisdictional allocator for MN Jurisdictional amounts.

[27] I assumed a 73.45% Minnesota jurisdictional allocator based on the Company response to Department information request no. 198 part a (DOC Ex.___ NAC-15 (Campbell Direct).

Q. Based on your review, do you recommend any adjustments to the Company's proposed levels of Energy Supply O&M expenses?

A. Yes I do. Based on my review of Energy Supply O&M costs, because these costs are up and down for 2012 to 2015 actual amounts, and because the 2016 test year amounts were 8.9% increase over 2015 actuals, I recommend a 4-year average using 2012 to 2015 actual amounts for setting rates for 2016 test year and I would propose the same adjustment for all test years 2016 to 2020 as shown below:

DOC Table 7: DOC Recommended Adjustments for Energy Supply O&M Expense

($ in millions)	2016	2017	2018	2019	2020	2012-2015 average
MN Jurisdictional[28]	$120.9	$123.9	$126.8	$125.4	$129.0	$115.375
DOC Adjustment	$5.525	$5.525	$5.525	$5.525	$5.525	

Q. Do you consider your adjustment of $5.525 million for 2016 to 2020 test years to be consistent with the way the Company handled their adjustments for the five-year rate plan?

A. Yes. In response of Department information request no.168,[29] the Company provided on Attachment A the rate case adjustments which shows the adjustments being carried across for each year.

Q. Do you have any additional concerns with the O&M Energy Supply amounts included in the test years?

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[28] I assumed a 73.45% Minnesota jurisdictional allocator based on the Company response to Department information request no. 198 part a (DOC Ex.___NAC-15 (Campbell Direct).

[29] DOC Ex. ___ NAC-16 (Campbell Direct).

A. Yes. In Department information request no. 1121[30], I asked the Company to demonstrate the reasonableness for Other Energy Supply O&M expenses, specifically, the 2015 actual land easement costs and the test year amounts for 2016 to 2018. On Attachment A, the Company provided its 2015 budget and actuals, plus the 2016 to 2018 test year amounts. I note in my review of Attachment A concerns that there were land easement costs included for Courtenay Wind of $1.2 million for 2017 and $1.205 million for 2018.

Q. Why are you concerned about Courtenay Wind land easement costs being included in Other Energy Supply O&M in 2017 and 2018 test years?

A. I am concerned about Courtenay Wind costs included in the test year amounts, because according to the Company, Courtenay Wind costs will be recovered through the RES Rider. As a result, the inclusion of the land lease costs for Courtenay Wind in the test year is not reasonable and will result in double recovery.

Q. What about the 2019 and 2020 test years?

A. Based on the way the Company determined their 5 year rate plan where they used a trend analysis for determining 2019 and 2020 test year amounts as shown on Schedule 13 of Mr. Burdick's Testimony, I believe the 2019 test year amount is $1.210 million and the 2020 test year amount is $1.215 million, based on the $5,000 increase from 2017 to 2018.

[30] DOC Ex. ___ NAC-17 (Campbell Direct).

Q. What is your recommended adjustment to Other Energy Supply O&M expenses to remove the Courtenay Wind land lease amounts incorrectly included in the rate case?

A. I recommend the following adjustments to Other Energy Supply O&M expenses to remove the Courtenay Wind land lease amounts incorrectly included in the rate case to avoid double recovery:

- $1.2 million reduction for 2017;
- $1.205 million reduction for 2018;
- $1.210 million reduction for 2019; and
- $1.215 million reduction for 2020.

X. NUCLEAR NON-OUTAGE O&M EXPENSES

Q. What Company witness addressed Nuclear O&M expenses and how were these expenses broken out?

A. Company witness Timothy O'Connor addressed Nuclear O&M expense in his Direct Testimony. Mr. O'Connor breaks out the Nuclear O&M expenses into two major categories, Non-Outage O&M expenses and Planned Outage O&M expense.

Q. Did Mr. O'Connor address the 2016 Test Year, and then the 2017 and 2018 test year drivers for nuclear O&M expenses under the Company's proposed 3-year MYRP?

A. Yes. Mr. O'Connor first addressed the 2016 test year and then the 2017 and 2018 test year drivers for Non-Outage O&M expenses and Planned Outage O&M expenses, respectfully.

Q. Did the Company use escalation factors or Company budgets for 2017 and 2018 nuclear O&M expenses?

A. The Company used both escalation factors and Company budgets for 2017 and 2018 nuclear O&M expenses. Company witness Mr. Burdick provided the following explanation on page 33 of his Direct Testimony:

> **Q. HOW WERE NUCLEAR O&M COSTS FOR THE PLAN YEARS 2017 AND 2018 DEVELOPED?**
>
> A. Two different methodologies were combined to develop the 2017 and 2018 Plan Years. Part of the expenses in each nuclear-related FERC Account (517-532) are forecasted using the Company's budget and part of the expenses are escalated using the IHS escalation factor. The portion that are forecasted are outage expenses that reflect the Company's planned outage schedule and are amortized between outages. Therefore the 2017 and 2018 Plan Year includes budgeted amounts for these amortization expenses. The base O&M portion of expenses in nuclear related FERC accounts are escalated 2016 Test Year amounts based on escalation factors from IHS.

Q. Based on your review of Nuclear O&M expenses, do you have any concerns about the reasonableness of Xcel's proposed level of Nuclear Non-Outage O&M expenses?

A. Yes I do. My concerns are focused on Non-Outage O&M expenses, specific my review and update of Mr. O'Connor's Table 7 as found on page 152 of his Direct Testimony.

Q. Did you ask the Company to update Mr. O'Connor's Table 7, which shows the Nuclear Non-Outage O&M expenses?

A. Yes. In Department information request no. 1188[31] I asked the Company to update Table 7 to include 2015 actual amounts and 2013 test year amounts.

[31] DOC Ex. ___ at NAC-18 (Campbell Direct).

Q. Did you prepare the below Table using Mr. O'Connor's Table 7 and the information provided in response to Department information no. 1188?

A. Yes.

DOC Table 8: Nuclear Non-Outage O&M Expenses

($ millions)	2012	2013	2014	2015 F	2015 A	2016 TY
Total Co.	$243.8	$265.7	$282.7	$277.3	$270.9	$281.3

Q. What did you notice based on your review of 2015 actual nuclear non-outage O&M expenses and 2015 forecasted expenses and compared to the 2016 test year requested amount?

A. Comparing 2015 actual nuclear non-outage O&M expense to the 2016 test year amount shows a 3.8% increase. Comparing 2015 forecasted amount for nuclear non-outage O&M expense to the 2016 test year amount shows a 1.4% increase. I also note that 2015 actuals were less than 2014 actuals.

Q. Has the Company replaced a significant amount of nuclear capital plant for Monticello, and replaced a steam generator for one of the Prairie Island nuclear plants in the last rate case?

A. Yes. As a result, when significant amount of a plant is replaced, there is an expectation that O&M expenses should decrease because the new plant would presumably require less maintenance during the earlier years of the plant or plant replacement.

Q. Given your observations, what do you recommend for purposes of determining a 2016 test year amount for nuclear non-outage O&M expense and what is the resulting adjustment?

A. I recommend a three-year average of 2013 to 2015 actuals, which results in $273.1 million. When comparing this three-year average of $273.1 million to the Company's 2016 test year amount of $281.3 million results in a downward adjustment of $8.2 million for nuclear non-outage O&M expenses on a total company basis. I assumed the same 73.45% Minnesota jurisdictional allocator I used for Energy Supply O&M expenses[32], which results in a $6.023 million downward adjustment to nuclear non-outage O&M expenses on a Minnesota jurisdictional basis.

Q. What rate recovery is the Company requesting for the five year rate plan 2016 to 2020 and how does that compare to the three-year average you recommend?

A. As shown on Attachments B and C in the Company's response to Department information request no. 1190[33], the following table presents the Company's proposed nuclear non-outage O&M expenses for 2016 to 2020 test years:

DOC Table 9: Summary of Company's Nuclear Non-Outage O&M Expenses

($ millions)	2016 TY	2017 TY	2018 TY	2019 TY	2020 TY	2013-2015 average
Total Co.	$281.3	$284.2	$290.7	$293.7	$298.1	$273.1
MN Juris.	$206.6	$208.7	$213.5	$215.7	$219.0	$200.6

[32] The Company response to Department information request no. 198 part a, shows a 73.45% Minnesota jurisdictional allocator.

[33] DOC Ex. ___ at NAC-19 (Campbell Direct).

Q. Consistent with your adjustment to Energy Supply O&M expenses, do you recommend the same adjustment for Nuclear Non-Outage O&M expenses for all test years 2016 to 2020?

A. Yes. I recommend basing rates on a three-year average of 2013 to 2015 actual costs. Comparing this three-year average of $273.1 million to the Company's 2016 test year amount of $281.3 million results in a downward adjustment of $8.2 million for nuclear non-outage O&M expenses on a total company basis. I assumed the same 73.45% Minnesota jurisdictional allocator that I used for Energy Supply O&M expenses,[34] which results in a $6.023 million downward adjustment to nuclear non-outage O&M expenses on a Minnesota jurisdictional basis for all test years 2016 to 2020.

XI. ALLOCATION – TRANSCO COSTS

Q. What adjustment did the Company propose in the current rate case to allocate the 2014 Transco related costs that were embedded in costs included in the prior rate case?

A. As shown in Volume 4B, Test Year Workpaper Adjustments, revised adjustment A34 the following is the 2014 total Transco costs and the allocation for the 3-year and 5-year rate plans:

2014 Transco Costs MN Jurisdictional	Annual Amortization 3-year Rate Plan	Annual Amortization 5-year Rate Plan
$138,450	$46,150	$27,690

[34] The Company response to Department information request no. 198 part a, shows a 73.45% Minnesota jurisdictional allocator.

Q. Did you ask the Company about its actual 2015 Transco costs and how they are returned to ratepayers?

A. Yes. In response to Department information request no. 1171 Attachment A,[35] the Company provided the 2015 Transco costs of $181,975 on a Minnesota jurisdictional basis and indicated that the Company was planning on making an adjustment to reflect this additional 2015 Transco costs in their amortization, which the Company will testify to in its Rebuttal Testimony..

Q. What would be the adjustment if the 2015 Transco costs were included into the annual amortization?

A. Below shows the 2014 and 2015 amortization of Transco costs on a Minnesota Jurisdictional basis. I note that the 2014 Transco costs are already included in the rate case through adjustment A34 and the 2015 Transco costs is my recommended additional adjustment for Transco cost amortization credit for Minnesota ratepayers.

2014 Transco Costs MN Jurisdictional	**Annual Amortization 3-year Rate Plan**	**Annual Amortization 5-year Rate Plan**
$138,450	$46,150	$27,690

2015 Transco Costs MN Jurisdictional	**Annual Amortization 3-year Rate Plan**	**Annual Amortization 5-year Rate Plan**
$181,975	$60,658	$36,395

XII. ALLOCATION – SERVICE COMPANY COSTS

Q. Did you ask the Company to demonstrate for each Commission ordering paragraph of the November 19, 2015 Commission's Order in Docket No. E002/AI-15-536 (Allocations for Service Company Agreement) how the adjustments for allocation changes were reflected in the current rate case for 3-year and 5-year rate plans?

[35] DOC Ex. ___ NAC-20 (Campbell Direct).

A. Yes. In response to Department information request no. 1169,[36] the Company explained and showed on Attachment A to its response that all of the adjustments for allocation changes were made, except for change for the New Direct Labor Ratio for the Rates and Regulation Service Function.

Q. In Attachment A to Department information request no. 1169, what was the expense adjustment for the New Labor Ratio for Rates and Regulation Service Function?

A. I note that the Company provided the following expense adjustments to reflect the New Labor Ratio for Rates and Regulation Service Function for 2016 to 2018 test years:

	2016	2017	2018
Rates & Regulation Service	($255,734)	($261,996)	($269,077)

Q. Did the Company provide the expense adjustments for 2019 and 2020?

A. No, the Company did not provide the expense adjustments for 2019 and 2020. As a result, I estimated the 2019 and 2020 expense adjustment to reflect the New Labor Ratio for Rates and Regulation Service Function based on the average increase of 2.6% for 2016 to 2018, which results in an adjustment of ($276,073) for 2019 and ($283,251) for 2020.

Q. What is your overall recommendation for Service Company allocations related to Docket No. E002/AI-15-536?

[36] DOC Ex. ___ at NAC-21 (Campbell Direct).

A. I recommend that the above adjustments for 2016 to 2020 be included in the test year to reflect the New Labor Ratio for Rates and Regulation Service Function.

XIII. HEALTH AND WELFARE AND BENEFITS EXPENSES

Q. Which Company witness addressed the Company's health and welfare expenses?

A. Company witness Richard Schrubbe addressed pension and benefits expense, which included the Company's health and welfare expenses.

Q. On page 10 of his Direct Testimony, did Mr. Schrubbe provide a summary of the Company's pension and benefit expenses?

A. Yes. On page 10 of his Direct Testimony, Mr. Schrubbe provided a Table 2 that showed the Company's pension and benefit expenses: 1) expenses approved in the last rate case, 2) 2015 forecast, and 3) 2016 to 2018 test years.

Q. Did you ask the Company to update Table 2 with some additional information?

A. Yes. In Department information request no. 1193,[37] I asked the Company to add to Table 2 the 2011 to 2015 actuals, the 2013 test year amounts, and explanations for material changes between 2015 forecast and 2015 actual. The Company provided this information on Attachment A to Department information request no. 1193.

Q. Based on your review of the Company's pension and benefit expenses on Attachment A in Xcel's response to your information request, do you have any concerns as to the reasonableness of the Company's proposed levels of pension and benefit expenses?

[37] DOC Ex. ___ NAC-22 (Campbell Direct).

A. Yes. Health and welfare expenses, which include active health care and life and long-term disability and miscellaneous benefits programs, appeared to be increasing significantly during the 2016 test year. Specifically, the Company is requesting a 7.9% increase for 2016 test year amounts compared to 2015 actual expenses for health and welfare. The Company is also requesting a 5.3% increase for 2017 plan year amounts compared to 2016 test year amounts, and a 5.7% increase for 2018 plan year amounts compared to 2017 plan year amounts, as shown in the table below.

Additionally, I noticed that 2015 actual health and welfare costs were $38,899,043, which was almost a $1 million or $949,801 lower than the Company's 2015 forecast of $39,848,844.

DOC Table 10: Health & Welfare Expenses for 2015 Actual & 2016-2018 TY

	2015	2016 TY	2017 TY	2018 TY
($ millions)	$38.899	$41.982	$44.190	$46.739
% increase		7.9%	5.3%	5.7%

Q. Are the percentage increases the Company is requesting for the 2016 to 2018 test and plan years higher than the increases the Company has actually experienced in 2011 to 2015?

A. Generally, yes. In the Table 11 below, I show the actual health and welfare expenses and the year-over-year increases for 2011 to 2015 compared to the 2016 test year amount requested. I note that, other than the relatively high increase from 2013 to 2014, the percent increases per year have ranged from 2.08% to 3.41%.

DOC Table 11: Health & Welfare Expense for 2011-2015 Actual & 2016 TY

	2011	2012	2013	2014	2015	2016 TY
($ millions)	$32.524	$33.200	$34.331	$37.580	$38.899	$41.982
% increase		2.08%	3.41%	9.47%	2.18%	7.9%

Q. Based on your review of the health and welfare expenses, has the Company demonstrated the reasonableness of its proposed levels of health and welfare expenses?

A. No, it has not, given its actual costs. Instead, I recommend that the Company's increase for health and welfare expense for 2016 to 2018 be limited to a 4.3% increase (instead of the Company's proposed 7.9% increase for 2016, 5.3% for 2017 and 5.8% for 2018), based on the average year-over-year increases actually experienced by the Company from 2011 to 2015. This recommended 4.3% increase includes the relatively high increase from 2013 and 2014, but also the much lower increases in the other years.

Q. What is your resulting adjustment for 2016 to 2018 based on your recommend 4.3% increase?

A. My recommended adjustments for 2016 to 2018 health and welfare expense are as follows:

- $1.410 million reduction for 2016;
- $1.873 million reduction for 2017; and
- $2.602 million reduction for 2018.

DOC Table 12: DOC Recommended Adjustments for Health & Welfare 2016-2018

($ in millions)	2015	2016	2017	2018
Co. Requested	$38.899	$41.982	$44.190	$46.739
DOC Recomm.		$40.572	$42.317	$44.137
DOC Adj. 4.3%		($1.410)	($1.873)	($2.602)

Q. What did the Company request for overall pension and benefit expenses for 2019 and 2020 test years?

A. According to Department information request no. 145,[38] the Company assumed a 2.5% increase in Administrative and General (A&G) costs, which includes all pension and benefits costs, for 2019 and 2020, as shown in the Direct Testimony of Mr. Burdick on Schedule 13.

Q. Do you have any concerns with the Company's assumed 2.5% increase for overall pension and benefits expenses for 2019 and 2020?

A. Yes. When reviewing Attachment A to Xcel's response to Department information request no. 1193, I notice that comparing 2013 to 2014 actuals results in a less than 1% increase (0.98%)[39] in overall costs. Additionally comparing 2014 to 2015 actuals results in a 1.0% overall increase. I note that during this time period pension expense is trending down and health and welfare costs are trending up, resulting in 0.99% or 1% average increase from 2013 to 2015.

I also note that comparing 2011 to 2012 actuals results in a 25% increase, which is largely due to pension costs and specifically the 2008 market loss that the

[38] DOC Ex. ___ NAC-23 (Campbell Direct).
[39] Calculated as the percent increase in Total FERC 926 costs, ($72,435,492 - $71,734,401)/$71,734,401.

Company already included in past rate recovery (despite Department objections). I also note that comparing 2012 to 2013 actuals results in a 7% *decrease*, again largely driven by the decrease in pension expense. As a result of the volatility in 2011 to 2013 due pension expense, and the fact that pension expense is now trending down and is expected to continue to trend down, I focused on the changes in total FERC 926 costs between 2013 to 2015 actuals which support a trend of a 1% increase year-over-year.

Q. Based on your review, has the Company demonstrated the reasonableness of its proposed levels of overall pension and benefits expenses?

A. No it has not.

Q. What is your recommended adjustment for pension and benefits for 2019 and 2020 test years?

A. I recommend a 1% average increase for overall pension and benefits expenses for 2019 and 2020 test years, instead of the 2.5% increase proposed by the Company.

DOC Table 13: DOC Recommended Adjustments for Overall Pension & Benefits Expenses for 2019 and 2020

($ in millions)	**2018 TY**	**2019 TY**	**2020 TY**
Co. Requested	$76.195	$78.1	$80.053
DOC Recomm.	$73.593[40]	$74.329	$75.072
DOC Adjust. 1%		($3.771)	($4.981)

[40] Company recommended $76.195 million less the $2.602 million DOC adjustment for health and welfare for 2018.

XIV. 401 NICOLLET MALL BUILDING LEASE

Q. Which Company witness discussed the 401 Nicollet Mall Building lease?

A. Lisa Perkett on pages 20 and 42-43 of her Direct Testimony discussed the 401 Nicollet Mall Building lease. On page 20 Ms. Perkett discussed the 10-year lease for office space at 250 Marquette Plaza that will be terminating at the end of 2016. The Company indicated that it evaluated different scenarios and selected OPUS as both a builder and landlord. Ms. Perkett indicated that 401 Nicollet Mall will be the new location and will be leased for 15 years, plus a leasehold addition of $16.7 million for interior offices, furniture and equipment amortized over 15 years.

Q. Did you ask some questions regarding the $16.7 million leasehold addition for 2016?

A. Yes. In Department information request no. 1136[41] I asked the Company to provide the following information:

- breakout by category the costs that make-up the $16.7 million leasehold addition;
- support for the 15 year recovery period and related salvage rate; and
- support for the expected in-service date for the leasehold addition.

Q. Did you have any concerns based on your limited review of the Company's responses regarding the leasehold addition?

A. No, the Company provided a high level breakout of the leasehold costs and indicated that the 15 year recovery was tied to 15 year lease and that the Company used a 0%

[41] DOC Ex. ___ NAC-24 (Campbell Direct).

salvage rate. However, I note that my review was very limited due to time constraints; thus, I intend to review testimony by other parties that may raise concerns based on their review of the leasehold additions for 401 Nicollet Mall.

Q. Did you ask several questions regarding the 15-year lease for 401 Nicollet Mall?

A. Yes. I asked the Company several questions regarding the 15-year lease for 401 Nicollet Mall in Department information request no. 1137 Supplement.[42] As discussed below, based on my review of the 401 Nicollet Mall lease, I recommend adjustments to the Company's lease and moving costs included in the 2016 to 2020 test years.

Q. What is the expected completion date of the 401 Nicollet Mall building by OPUS and when will the Company be able to move in and use this building?

A. The Company indicated in its response to Department information request no. 1137 supplement that the building was completed in April 2016 and the Company plans to fully occupy the building by May 20, 2016.

Q. What information did you ask the Company to provide regarding the 205 Marquette Plaza office lease and the 401 Nicollet Mall office lease?

A. I asked the Company to provide the actual costs for 2014 to 2016 for Marquette Plaza office lease and to compare these costs to the 401 Nicollet Mall office lease costs. Additionally, I asked the Company to identify the office lease costs for 250 Marquette Plaza that were excluded from the three-year and five-year rate plans.

[42] DOC Ex. ___ NAC-25 (Campbell Direct).

Q. What did you notice based on your review of the Marquette Plaza actual lease costs for 2014 and 2015 compared to the 2016 amount included in the test year for Marquette Plaza?

A. I noticed that the Marquette Plaza lease costs included in the 2016 test year appeared too high based on the Company's indication that the Marquette lease would terminate at the end of June 2016, which would mean six months of lease costs. The Company's Attachment A to Department information request no. 1137 Supplement[43] provided the following Marquette lease cost information for 2014 to 2016 (on a NSPM electric basis):

- 2014 actual for one year - $3,068,739;
- 2015 actual for one year - $3,083,090; and
- 2016 actual for six months - $1,983,461.

Q. Why do you conclude that the 2016 test year amount for the Marquette Plaza lease for six months is too high?

A. When I take one-half or six months of the 2015 actual costs above, the amount is $1,541,545 for six months of lease expense, not the $1,983,461 amount; Xcel's figure reflects a $441,916 increase, which is close to 8 months of lease expense included by the Company in the 2016 test year.

Q. What concern do you have with the 401 Nicollet Mall rent expense for 2016 test year?

[43] DOC Ex. ___ NAC-25 (Campbell Direct).

A. As shown on Attachment A, the annualized rent expense for 2016 would be $6,427,071 but comparing this figure to the 2017 annualized rent expense of $5,750,472 (both numbers are on an NSPM electric basis) on Attachment A and B indicates that 401 Nicollet Mall rent expense is too high for 2016.

Q. Given the small difference between six and eight months of rent in 2016, do you have a bigger concern about how the Company calculated and overstated rent expense for 2016?

A. Yes. I note that the Company may even be able to justify some overlap of rent expense for 2016 test year, although they haven't supported that based on the current record. However, the Company used its 2016 overstated rent expense for 2017 to 2020 and additionally escalated the amount using a FERC accounting escalator, not tied to actual lease costs.

Q. What other concerns do you have about the total expenses shown on Attachment A in Xcel's response to Department information request 1137 Supplement?

A. The Company also included one-time moving expenses of $1,370,004 on an NSPM electric basis for 2016 and then did not exclude these costs for 2017 to 2020. Additionally, the moving expenses were incorrectly escalated for 2017 and 2018.

Q. Are you concerned about the Company's over use of escalation rates?

A. Yes, for the Prairie Island Settlement amount discussed below and for both the rent and moving costs for the new 401 Nicollet Mall office lease, the Company has escalated costs that I believe are not actually going to increase, and therefore, the

Company may in effect over charge customers. I am also concerned that there may be other costs like this that I have not identified.

Q. Did the Company provide some updated information regarding rent expenses, moving expenses, including correct the Minnesota jurisdictional amount?

A. Yes. After a phone call meeting with the Company to better understand the costs related rent expense, moving costs, and other items, the Company provided Attachments G and H in response to Department information request no. 1137 Supplemental[44]. This attachment helps clarify the costs included in the test year for 2016 to 2018 for rent expense, moving expense, and other items. Additionally, the Company indicated that they did not include the Wisconsin interchange allocation for Attachment A and B, but did include this for Attachment G.

Q. Based on your review, has the Company demonstrated the reasonableness of its proposed levels of rent expense?

A. No, it has not. Attachment G shows and corrects the following based on my concerns:

- lines 75 and 76 shows the reductions to both the Marquette Plaza and 401 Nicollet Mall lease for the extra months included in 2016;
- line 77 removes the Marquette Plaza lease from 2017 and 2018;
- line 78 removes the one-time move costs from 2017 and 2018;
- line 79 adds the 401 Nicollet Mall lease to annualize the lease expense for a full year for 2017 and 2018;

[44] DOC Ex. ___ NAC-25 (Campbell Direct).

- line 80 shows the net adjustments based on the above for 2016 to 2018.

Q. Based on your review, what are your recommend adjustments for 2016 to 2020?

A. I used the net adjustments for 2016 to 2018 and then determined the 2019 and 2020 levels based on a percent of increase trend. I recommend the following adjustment to normalize the lease expenses and remove the moving expenses:

DOC Table 14: Normalization of Leases and Remove Moving Expenses

($ in 000s)	2016	2017	2018	2019	2020
DOC adj	($506)	($632)[45]	($759)	($844)	($941)

XV. NON-ASSET BASED TRADING

Q. What is the expense credit for non-asset based trading for the 2016 test year?

A. First, I note that the expense credit for non-asset-based trading is a required adjustment to ensure that ratepayers do not subsidize Xcel's non-regulated activities in this area. Second, according to Ms. Heuer's Schedule 18 page 11 of 11, attached to her Direct Testimony, the expense credit for non-asset based trading for the 2016 test year is $984,910 on a Minnesota jurisdictional basis.

Q. What is the expense credit for non-asset based trading for the 2017 and 2018 plan years?

A. According to the Company's response to Department information request no. 169 part (f), the Company used the escalation rates for FERC accounts 920 and 921 to determine the 2017 and 2018 test year amounts. Mr. Burdick's Schedule 8 page 3

[45] I noted a 2.5% increase from 2016 to 2017 and a 20% from 2017 to 2018, and therefore I assumed an 11.25% average increase.

of 3 shows the following escalation factors for FERC accounts 920 and 921 for 2017 and 2018:

- FERC account 920 shows a 2.8581% escalator for 2017;
- FERC account 920 shows a 2.8469% escalator for 2018;
- FERC account 921 shows a 1.8059% escalator for 2017; and
- FERC account 921 shows a 1.8572% escalator for 2018.

Based on the above escalators, the Department calculated the escalator for 2017 to be 2.332% based on a 50% equal weighting of the FERC accounts 920 and 921 escalators. Additionally, the Department calculated the escalator for 2018 to be 2.3521% based on a 50% equal weighting of FERC accounts 920 and 921 escalators. So the resulting expense credit for non-asset based trading for 2017 and 2018 is $1,007,878 and $1,031,584, respectfully.

Q. When you reviewed the actual O&M expense, which makes up the majority of the expense credit for non-asset based trading, what did you notice?

A. In reviewing Ms. Heuer's Schedule 18 page 8 of 11, I noted that O&M expenses for 2012 to 2014 increased every year. Additionally, Xcel's response to Department information request no. 169 indicated that O&M expenses for 2015 continued to increase. Below I provide the O&M expenses included in the 2016 test year compared to the 2012 to 2015 actuals.

DOC Table 15: 2012-2015 Actual O&M Expense for Non-Asset Based Trading Compared to 2016 Test Year

	2012	2013	2014	2015	2016 TY
O&M Exp.	$959,061	$987,006	$1,105,086	$1,565,027	$967,621

Q. Is it reasonable to give ratepayers a credit for O&M expense for non-asset based trading based on an amount that is lower than actual O&M expenses for the past three-years 2013 to 2015?

A. No; doing so would mean that ratepayers would unduly subsidize Xcel's unregulated activities. Every year from 2012 to 2015 the actual expenses for non-asset based trading have been trending upward, so it is not reasonable for the Company to use a significantly lower expense level for the 2016 test year in calculating the credit to be given to ratepayers.

Q. In response to Department information request no. 169 part (b)[46] what reason did the Company provide for why 2016 O&M expense are expected to be lower?

A. According to the Company, at the time the budget was created 2016 staffing would be at a lower pay grades than 2014.

Q. Do you agree that the Company's response is reasonable?

A. No. I don't think I have seen the Company lower any payroll costs for regulated business, so it is difficult to believe that it would do so for non-regulated business. Additionally, I would have more faith in the Company's response if there was some decrease in 2015 expenses; however, 2015 expenses were higher than ever.

Q. What do you recommend for setting the non-asset based trading O&M expense level in the credit to ratepayers?

[46] DOC Ex. ___ NAC-26 (Campbell Direct).

A. Since the actual 2012 to 2015 O&M expenses continued to increase, I recommend that the O&M expense level for the most recent year 2015 of $1,565,027 be used for setting 2016 test year credit for O&M expenses for non-asset based trading. For 2017 to 2018 plan years, I recommend using the same escalation rates calculated above for 2017 and 2018, plus the average increase for 2019 and 2020.

Q. What is your resulting adjustment based on your recommend for non-asset based trading?

A. In the below table I show my recommended adjustment for 2016 to 2020 O&M expense credit for non-asset based trading (note that this is only the O&M portion, which makes up the majority of the total credit):

DOC Table 16: DOC Adjustment for O&M Expenses for Non-Asset Based Trading

	2016	2017	2018	2019	2020
Co Req.	$967,621	$990,186	$1,013,476	$1,037,314	$1,061,713
DOC Rec.	$1,565,027	$1,601,523	$1,639,192	$1,667,748	$1,706,975
DOC Adj.	($597,406)	($611,337)	($625,716)	($630,434)	($645,262)

XVI. PRAIRIE ISLAND SETTLEMENT PAYMENT

Q. What is the Company's rate recovery proposal related to the Prairie Island Indian Settlement Agreement costs?

A. According to Ms. Heuer on page 106 of her Direct Testimony, the Company included in the 2016 test year $2.5 million associated with the Settlement Agreement as amended April 20, 2015, between the Company and the Prairie Island Indian Community. According to the Company these costs should have been directly assigned to the Minnesota electric jurisdiction, but instead they were allocated to all NSPM jurisdictions. The Company has proposed to make an adjustment in Rebuttal

Testimony to reflect the direct assignment of these costs. The Company noted that this adjustment will increase test year revenue requirements of $0.663 million and support for this adjustment can be found in Volume 4 Test Year Workpapers, Section X Rebuttal Adjustments, Tab R-3.

Q. When you sent information requests asking about the rate recovery for the PI Settlement costs, did the Company's answer change?

A. Yes. I asked the Company to provide supporting calculations and adjustments recommended by the Department for the PI Settlement Agreement in Department information request no. 2124. The Company provided in part (a) of its response the following table to show the actual rate recovery requested for 2016 to 2018 test years, including that the PI Settlement Agreement costs were allocated to all NSP jurisdictions (MN, ND, SD and WI):

DOC Table 17: Company's Proposed Rate Recovery in Direct Testimony for PI Settlement

	Total NSPM	MN Juris.	ND Juris.	SD Juris.	Wisc. Juris.
2016	$2,500,00	$1,837,214	$130,624	$135,535	$396,628
2017	$2,538,667	$1,865,629	$132,644	$137,631	$402,762
2018	$2,584,270	$1,899,143	$135,027	$140,104	$409,997

Q. What rate recovery for PI Settlement did the Company request for 2019 and 2020 test years?

A. According to the Company's response to Department information request no. 2124 part (b)[47], the 2019 and 2020 forecasts included PI Tribal Community payments of

[47] DOC Ex. ___ NAC-27 (Campbell Direct).

$2.5 million for 2019 and 2020. Additionally, the Company's response to Department information request no. 183 revised references to Mr. Burdick's Schedule 13 and the fact that his Schedule 13 only includes the Minnesota jurisdictional amount of $2,183,652 for 2019 and 2020, consistent with the 2016 test year.[48]

Q. Do you agree that the Company's response that 2019 and 2020 years only included $2.5 million for PI Settlement payments is reasonable?

A. No. Mr. Burdick's Schedule 13 does not show the PI Settlement Agreement amount as a separate line item; thus I conclude that the PI Settlement Agreement amount is included in the nuclear O&M category, which shows a 6.0% increase from 2017 to 2018 and a 3.2% increase from 2017 to 2018. Therefore, the PI Settlement Agreement is inappropriately escalated due to the overall increases in nuclear O&M for 2019 and 2020 compared to 2017 and 2018, which did include the escalated amounts for the PI Settlement Agreement.

Q. Did you ask the Company to calculate the adjustment for the Settlement Agreement costs to exclude the escalation factor?

A. Yes. In response to Department information request no. 2124 part (a)[49] the Company provided the following adjustments for 2017 and 2018 to exclude the escalation factor:

- $28,416 decrease in nuclear expense for 2017 and
- $61,929 decrease in nuclear expense for 2018.

[48] DOC Ex. ___ NAC-28 (Campbell Direct).
[49] DOC Ex. ___ NAC-27 (Campbell Direct).

Q. Do you recommend an adjustment for 2019 and 2020?

A. Yes. I assumed Mr. Burdick's Schedule 13 incorporates the same increase from 2017 to 2018, shown above, to the 2019 and 2020 test years. As a result, I also recommend the following adjustments for 2019 and 2020 to exclude the escalation factor:

- $101,495[50] decrease in nuclear expense of 2019 and
- $148,183[51] decrease in nuclear expense of 2020.

Q. Please summarize your recommendations to the support the 2017 to 2020 adjustments to the Settlement Agreement recovery of the Company.

A. I conclude that it is not appropriate to escalate the Settlement Agreement costs above the $2.5 million statutory cap. Under the Settlement Agreement the Company is only paying $2.5 million per year. In addition, I note that this is an example supporting why a generic escalation of all O&M costs for 2017 and 2018 is not appropriate. Specifically, because of the way the Company proposed their 5-year rate request as shown on Mr. Burdick's Schedule 13, using a general trend analysis that assumes, for example, that all nuclear O&M costs increase by 6% from 2017 to 2018 results in Company requesting a 6% increase for 2018 over their 2017 base nuclear O&M expense which included the escalated amount for the Settlement Agreement.

XVII. PRAIRIE ISLAND (PI) FIRE PROTECTION PROGRAM IN-SERVICE DATE

Q. What Company witness addressed the PI Fire Protection Program?

[50] $33,513 incremental 2017 increase * 118% = $39,566 plus $61,929 (2018 cumulative amount).
[51] $39,566 incremental 2018 increase * 118% = $46,688 plus $101,495 (2019 cumulative amount).

A. Company witness Timothy O'Connor addressed the PI Fire Protection Program on pages 76 to 80 of his Direct Testimony.

Q. According to the Company what is the description of this project?

A. Mr. O'Connor provided the following information description of the Fire Protection Program on pages 76-77:

> Nuclear's fire protection requirements under operating licenses are codified in Federal regulations (referred to as Appendix R[52]). However, Appendix R provides some requirements that cannot readily be met regarding the separation of safety related equipment in the event of a fire. As this became an industry issue, the [Nuclear Regulatory Commission] NRC offered nuclear operators a choice to comply with fire protection standards under one of two alternatives, at the operator's option. One option is the deterministic model under Appendix R. The other option is following the risk-informed, performance-based approach established by the National Fire Protection Association (NFPA) under its Standard No. 805.[53] Implementation of an NFPA 805 program requires an NRC License Amendment Request (LAR). Implementation of all approved LAR projects is a condition of maintaining an operating license in good standing. The NRC has granted extensions of fire protection program compliance under NFPA 805 without regulatory findings (for non-compliance with Appendix R). The NRC compliance process for fire protection under NFPA 805 is then defined with the LAR approval schedule.
>
> We evaluated the options for each of our sites. Monticello has proceeded with Appendix R requirements as its fire protection program. Prairie Island elected NFPA 805 requirements to provide more time to resolve its fire protection risk issues, and avoid potential non-compliance and NRC findings during the time it would

[52] Federal Regulation 10 CFR 50, Appendix R.

[53] NFPA 805: Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants was originally issued in 2001 and has issued revised editions four times since then, with the latest in 2015.

> take to comply fully with the Appendix R program. The NFPA 805 project scope at Prairie Island includes development of a fire protection model (evaluating risk to reactor core damage) and performance of 32 plant modifications to implement fire protection elements, which will be completed in stages through 2020. This NFPA 805 modeling complies with NRC regulations for fire protection.

Q. According to the Company what is the benefit of proceeding with the PI Fire Protection Program?

A. On page 78 of his Direct Testimony, Mr. O'Connor provided the following response:

> The NRC allowed the choice of fire protection programs under either Appendix R or NFPA 805. Our analysis determined that the NFPA 805 risk informed approach was more cost effective to mitigate the risks of reactor core damage frequency and large early radiation release, and to ensure the safe shutdown of the Prairie Island plant in the event of a fire. Using an Appendix R at Prairie Island would be cost prohibitive and uneconomical to address pending fire protection nonconformances (now being addressed throughout the NFPA 805 program) through the NRC's significance determination process.

Q. Did the Company provide a description of the PI Fire Protection Program costs?

A. Yes. Mr. O'Connor on page 79 of his Direct Testimony provided the following description of the project costs:

> The 2016 capital addition for this project is $18.2 million, including AFUDC. The project costs include employee labor, outside contractors, materials and equipment, employee travel expenses, and other costs associated with regulatory compliance. The costs include engineering and construction work for fire model development and implementation, and regulatory compliance activities for LAR preparation and submittal.

Q. Did you ask the Company to demonstrate the reasonableness for the in-service date for the PI Fire Protection Program for the 2016 capital addition of $18.2 million?

A. Yes. In response to Department information request no. 1181 part (a) the Company provided the following:

> The budgeted in-service date for the next phase of the PI Fire Protection Program (NFPA 805 Program Implementation) is November of 2016, with implementing fire model programmatic elements from 2nd quarter through 4th quarter of 2016. The program's final implementation – of additional plant modifications for fire protection -- must await the receipt of the approved Final NRC Safety Evaluation (SE). The final site modification scope from this project will be known once the pending License Amendment Request is approved by the NRC through the issuance of the SE. In-servicing of fire protection project costs will occur and continue as the final modifications are installed and tied into the operating plant. As Company witness Mr. Scott L. Weatherby's Supplemental Direct Testimony Schedule 8 shows, additions for this project are anticipated in each of the years 2016-2020 as the final approved fire model and related modifications are implemented. The $18.2 million being in-serviced in 2016 is based on the implementation of the NFPA805 Fire Model, and the first plant modification, 72E Fire Detection Installation.

Q. What did Scott Weatherby's Supplemental Direct Testimony Schedule 8 show for capital expenditures for 2016 to 2020 for the PI Fire Protection Program?

A. Mr. Weatherby's Schedule 8 provided all the capital expenditures for the projects the Company considers to be NRC-mandated capital projects, including the capital expenditures for 2016 to 2020 for the PI Fire Protection Program:

Northern States Power Company
Electric Utility – State of Minnesota

Docket No. E002/GR-15-826
Exhibit___(SLW-1), Schedule 8
Page 1 of 1

Prairie Island Nuclear Plant
Mandated Compliance Capital Expenditures (excluding AFUDC)

Mandated Compliance Projects	Requirement Being Met	Forecast 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Total 2016-2020
Fire Protection	NFPA 805 Requirements	$16,794,494	$18,180,245	$11,210,953	$4,386,364	$760,008	$51,432,064
External Events - Fukushima Requirements	NRC 2011 & Related Orders	$9,000,000	$940,000	$200,000			$10,140,000
Security Upgrades including Cybersecurity	NRC 10 CFR 73 & Inspection Requirements	$1,572,989	$2,530,000	$5,750,000			$9,852,989
Tornado Missile/Projectile Protection	NRC Regulatory Issue 2015-06		$1,000,000	$2,000,000	$2,000,000	$2,000,000	$7,000,000
16 KV Bus Modification	Commitment made in 2/3/14 response to NRC Request for Additional Information	$2,122,102	$3,359,995	$1,856,839	$707,367		$8,046,303
Steam Generator Water Level	NRC Regulatory Guide Section 1.97	$2,550,000	$50,000				$2,600,000
Total Prairie Island Mandated Compliance Capital Expenditures		$32,039,585	$26,060,240	$21,117,792	$7,093,731	$2,760,008	$89,071,356

Q. What is the status of the NRC approval needed, which the Company estimated to occur by April 30, 2016?

A. The Company provided the following in response to Department information request no. 1181 part (b)[54]:

> NRC approval is now expected in the 3rd quarter of 2016. The date was pushed back due to Requests for Additional Information (RAI) that were received from the NRC in 2015. Resolution of the RAIs is needed prior to the NRC's issuance of the Safety Evaluation, which constitutes approval of this project. With our having completing our responses to all RAIs received, we expect the NRC will issue the Safety Evaluation in the 3rd quarter of 2016.

Q. Based on your review, do you have concerns with the Company meeting its estimated in-service date for the PI Fire Protection Program?

A. Yes. The Company indicated in Direct Testimony that they expected an April 30, 2016 approval date from the NRC, but now based on the above response, the Company expects a 3rd quarter of 2016 approval date from the NRC. As a result, it is

54 DOC Ex. ___ NAC-29 (Campbell Direct).

not reasonable to base rates on the assumption that the Company could still meet its expected November 2016 in-service date, which was based on the earlier April 30, 2016 NRC approval. At a minimum, given that Xcel's assumptions for NRC approval appear to be overly optimistic assumptions by at least 6 months, rates should be based on Xcel's capital additions for the Fire Protection Program to be in-service no earlier than the early part of 2017. While still generous to Xcel, I recommend moving the November 2016 in-service date to January 2017.

Q. Did you ask the Company to calculate the adjustments for 2016 to 2020 test years assuming a later-than January 1, 2017 in-service date for the 2016 capital addition of $18.2 million for the PI Fire Protection Program?

A. Yes. The Company provided the following response to Department information request no. 1181 part (c):

> Attachment A to this response provides a summary of the changes to Minnesota jurisdictional revenue requirements for 2016-2020 if the $18.2 million test year additions for PI Fire Protection in 2016 is assumed to occur in January 2017.

Q. What are the resulting Minnesota jurisdictional revenue requirement adjustments shown on Attachment A to Department information request no. 1181 part (c)[55]?

A. The resulting Minnesota jurisdictional revenue requirements adjustments for 2016 to 2018 based on moving the PI Fire Protection Program for the 2016 capital addition of $18.6 million from a November 2016 in-service date to the January 2017 in-service date I recommend are as follows, with Xcel's proposed revenue requirement for 2016 decreasing and the revenue requirements for the subsequent four years

[55] DOC Ex. ___ NAC-29 (Campbell Direct).

increasing somewhat to reflect the higher levels of rate base in those years compared to the assumed levels in Xcel's proposed rates.

DOC Table 18: Revenue Requirement Impact of Fire Protection Program Change to In-Service Date

($ in 000's)	2016	2017	2018	2019	2020
MN rev req	($2,969)[56]	$380	$573	$500	$404

Q. Do you have any additional concerns besides the proposed 2016 capital addition for the PI Fire Protection Program discussed above?

A. Yes. As discussed in Mr. O'Connor's Direct Testimony on pages 109 and 120, the Company proposes capital additions for 2017 of $9.1 million and for 2018 of $4.6 million. Additionally, based on Mr. Weatherby's Schedule 8 above, which shows capital expenditures for every year 2016 to 2020, I believe there are capital additions for all of the MYRP years 2016 to 2020. Because of my concern that the 2016 capital additions for the Fire Protection Project will not be in-service in November 2016, but rather January 2017, I am concerned that the Fire Protection Program's capital additions for 2017 to 2020 should also be moved back one-year. It is unlikely that the Company will be able to catch-up when they have phases of the Fire Protection Project to do each year 2016 to 2020. Thus, with the 2016 in-service date moving to 2017, all the in-service dates for the Fire Protection Program should move back one year.

Q. What do you recommend that the Company address in its Rebuttal Testimony?

[56] By email the Company indicated that because of the Construction Work in Progress (CWIP) balance, the plant receives a return for all of 2017 and depreciation was recorded for 11 ½ months for 2017.

A. I would like the Company to address:

- why the 2017 to 2020 capital additions for the Fire Protection Program should not be moved back one year, based on Xcel's current expectations as to NRC approval and the Department's recommended later in-service date, for November 2016 capital additions to move to January 2017, and
- the revenue requirement calculations for moving the 2017 to 2020 capital additions for the Fire Protection Program back one-year, including exclusion of the 2020 capital additions (the last year of the MYRP).

XVIII. MONTICELLO DRY FUEL STORAGE (DFS) LOAD CASK NO. 16, INCREASED CAPITAL COSTS

Q. Did the Company provide a description of the Monticello DFS Load Cask No. 16 Project?

A. Yes. Mr. O'Connor provided the following description of the project on page 62 of his Direct Testimony:

> The Monticello 2013 DFS – Load Cask #16 project relates to the procurement, loading and transfer of one cask (#16) containing fuel assemblies from the site's spent fuel pool in the plant to dry cask storage in the site's ISFSI facility, including costs to resolve the dye penetrant weld examination issues.

Q. Did the Company provide information regarding the project cost?

A. Yes. Mr. O'Connor provided the following information on page 62 of his Direct Testimony:

> The 2016 capital addition for this project is $19.4 million, including [allowance for funds used during construction] AFUDC. The project costs include employee labor, outside contractors, materials and

> equipment, employee travel expenses associated with the project, and other costs such as equipment rental. The additions placed in service include AFUDC accrued during the project's duration. The costs include activities for engineering of program phases, construction of implementation work, and procurement of materials. The budgeted capital addition for 2016 represents the costs associated with the design, engineering, management, oversight, procurement, loading and placement of Cask #16, including those costs incurred to resolve the dye penetrant weld examination issues.

Q. Is this cost the same amount that the Company originally budgeted for this project?

A. No. According to the Mr. O'Connor on pages 63-64 of his Direct Testimony:

> The budgeted amount for the Monticello 1 Dry Cask #16 project has increased over time. The original budget for the 10-cask loading campaign planned for 2013 was about $4 million per cask.
>
> The original budget for capital expenditures was established prior to project commencement in 2013 based on the planned scope, estimated cost, and established activity schedule for the project (which initially included loading 10 casks at Monticello, Casks #11-20). AFUDC is accrued on actual expenditures according to Company policy, compliant with FERC guidelines, while the project is in progress. Our initial plan was to complete loading all of Casks #11-20 in late 2013. The initial capital budget for this work was exceeded due to technical issues caused by vendor performance in 2013, as I discuss later.
>
> The remaining expenditures forecasted for this project are therefore based on our projection of the work necessary to address the Cask #16 technical issues with the NRC, which we currently anticipate will take until at least mid-2016 to resolve. We have filed an exemption request with the NRC to approve our work on the cask as sufficient to mitigate the vendor performance issues noted. Our forecasted cost assumes the NRC will approve our exemption request by mid-2016, and we can place Cask #16 in service in the test year.

> That said, the NRC has indicated it may take some time to review our exemption request and act on it, so we may not have a final disposition from the NRC until the end of 2016. Because of the uncertainty in the steps and timeline in bringing the Cask #16 issue to closure, at this time we are including the costs in our proposed final rates (but not in our proposed interim rates) to allow the NRC review and vendor 1 dispute processes to play out.
>
> Finally, we also face the risk of the NRC requiring additional inspections in the future on Casks 11-15, which have been placed in the IFSFI storage facility. No costs for these additional inspections, should they be required, are included in our capital budgets or O&M expenses for this rate case.

Q. Did the Company discuss the NRC compliance issues associated with cask no. 16 and the vendor weld issue?

A. Yes. Mr. O'Connor provided the below information on page 65 of his Direct Testimony and provided addition detail on pages 65-70 of his Direct Testimony:

> With respect to Dry Cask #16 at Monticello, our 1 dry cask loading vendor, TriVis, Inc., failed to follow all of its procedures for post-weld examinations of loaded casks. These examinations are surface evaluations for cracks. Examination procedures required placing dye on the welds for at least 10 to 15 minutes before checking for cracks; however, TriVis workers did not adhere to the required wait time. **The preliminary NRC findings from their investigation of this issue faulted both TriVis contractors (who conducted the work) and Xcel Energy (which is responsible for oversight) for these improper examination procedures.** The preliminary findings stated that the vendor not only failed to follow the required waiting times, but also inaccurately documented the waiting times to make them appear to be consistent with the requirements of its examination program procedures. **[Emphasis added]**

Q. Have you attached a copy of the NRC letter dated July 23, 2015 which addressed the weld issue with cask no. 16?

A. Yes. This July 23, 2015 letter is the initial NRC finding regarding the failures of Xcel and the contractors regarding cask welds. As to Xcel's failure "the NRC determined that the licensee apparently did not assess the effectiveness of the control of quality by contractors in that the licensee apparently did not monitor the work of contractors performing PT testing on DSCs #11 through #16."[57]

Q. Did you ask the Company to confirm that the original cost of completing and loading cask no. 16 was $4 million in 2013, and has not increased to $19.4 million in the 2016 test year, due to the vendor weld issues?

A. Yes. In response to Department information request no. 1179 part (a)[58] the Company provided the following response:

> The cost of the 10-cask loading project initially planned for Monticello in 2013 was projected as approximately $43 million, or an average of $4.3 million per cask (including AFUDC). That average cost reflects economies of scale that can be obtained from mobilizing resources and procuring equipment for multiple casks rather than a single or small number of casks. Once the issues were encountered that required us to split the 10-cask load into three separate loadings, as discussed in our response to Department Information Request No. 1186, a single cask could no longer be loaded for the average per-cask cost of a 10-cask load. The Company also incurred additional costs in connection with interim storage of Cask #16, the alternative weld examination method, and the NRC exemption process. The updated cost estimate for Cask #16 loading is $19.4 million (including AFUDC) as discussed in Mr. Timothy J. O'Connor's Direct Testimony pages 62-68. That testimony describes the factors driving the cost increases in greater detail.

[57] DOC Ex. ___NAC-37 (Campbell Direct).

[58] DOC Ex. ___ NAC-30 (Campbell Direct).

Q. Did you ask the Company to identify the current status of the NRC approval for this project and support the current summer 2016 in-service date?

A. Yes. The Company provided the following responses to Department information request no. 1179 parts (c) and (d)[59] regarding the status of the NRC approval and support for the Summer 2016 in-service date:

> (c) Our exemption request regarding Cask #16 is still being reviewed by the NRC. We have received and replied to the NRC's requests for additional information and still anticipate NRC approval by mid-2016. Once we have NRC approval, Cask #16 can be moved to the ISFSI facility on-site and placed in service. **Due to limited availability of specialty work crews needed to support this cask move, in-servicing is now anticipated to occur later in 2016 (October).**
>
> (d) As discussed in part (c) above, we now expect NRC approval by mid-2016 and a fall 2016 in-service date for Cask #16. We have completed the loading of Cask #16, and we anticipate that the actual work of moving the cask will take approximately one month. However, before we can begin the move, we need to mobilize the specialty work crews to perform the work. Assuming that we obtain NRC approval by mid-year, we anticipate that we can mobilize the crews and complete the move by fall 2016. Once the cask is moved, it is considered placed in service and a completed addition. [emphasis added].

Q. Based on the Company's response above the in-service date for cask no. 16 is expect to be October 2016, instead of Xcel's initial estimate of the summer 2016, is that correct?

A. Yes. At a minimum, the revenue requirements should reflect the later in-service date of October 2016 for the cask no. 16 project.

[59] DOC Ex. ___ at NAC-30 (Campbell Direct).

Q. What is your recommendation based on your review of the weld issue related to Monticello cask no. 16?

A. I recommend that the increase in capital costs of $15.1 million ($19.4 million less $4.3 million) due to the weld not being done correctly by the vendor and not correctly supervised by Xcel not be recovered from ratepayers. The NRC noted in its letter that it is the licensee's responsibility to oversee vendors, and Xcel did not oversee the vendor performing the welding for casks no. 11 to 16.

On July 16, 2014 Xcel filed an exemption request pursuant to 10 CFR 72.7 with the NRC for cask numbers 11 to 16. However, on December 16, 2014 Xcel withdrew this exemption request. As noted by Mr. O'Connor above, on September 29, 2015 Xcel filed a similar exemption request with the NRC for cask number 16 only. The September 2015 exemption request notes that cask numbers 11 to 15 are loaded into the horizontal storage modules. Beyond that information the Department does not know the regulatory status of cask numbers 11 to 15.

Q. Did you ask the Company to provide the revenue requirement adjustments for 2016 to 2020 to exclude the increased capital costs of $15.1 million for cask no. 16?

A. Yes. In response to Department information request no. 1179 part (b) the Company provided the following:

> Attachment A to this response provides a summary of the changes to Minnesota jurisdictional revenue requirements for 2016-2020 if the $19.4 addition for Cask #16 in mid-year 2016 was lowered to $4.3 million.[60]

[60] DOC Ex. ___ NAC-30 (Campbell Direct).

DOC Table 19: Revenue Requirement Impact of Removing $15.1 Million in Capital Costs for Monticello Cask # 16

($ in 000's)	2016	2017	2018	2019	2020
MN rev req	($640)	($1,475)	($1,422)	($1,368)	($1,318)

XIX. SPENT FUEL STORAGE FOR MONTICELLO

Q. What amount was approved for Monticello spent fuel storage?

A. In Xcel's initial petition in Docket No. E002/CN-05-123 on page 3-40, the Company provided the following estimated installed capital costs for the Monticello Independent Spent Fuel Storage Installation (ISFSI) in 2004 dollars:

Regulatory Process	$2.0 million
Engineering & Design	$12.0 million
Plant Upgrades	$4.0 million
ISFSI Construction	$3.5 million
30 Canisters & Storage Modules	$26.0 million
Canister Loading Campaigns	$7.5 million
Total	**$55.0 million**

Q. What would be the escalated amount in today's 2016 dollars?

A. The Company provided in response to Department information request no. 91[61] in Docket No. E002/RP-15-21 (Xcel's 2015 Integrated Resource Planning) that the inflation rate assumed for spent fuel storage by the Company was 3% per year. As a result, the $55 million in 2004 dollars inflated by 3% per year results in $78.42 million in 2016 dollars.

Q. What has the Company incurred and what does it expect to incur through 2020 for Monticello spent fuel storage capital costs?

[61] DOC Ex. ___ NAC-31 (Campbell Direct).

A. According to the Company's response to Department information request no. 2123,[62] Attachment A, line U, the Company actual capital costs from 2004 to 2014 plus budgeted capital costs included in the test years for 2016 to 2020 is $130.0 million. I note that the Company shows the last 10 casks for Monticello being completed in 2018.

Q. What is the amount of costs that will exceed the CN estimate for Monticello spent fuel storage capital costs?

A. Using the $130.0 million provided by the Company in actual costs and costs budgeted in the current rate case through 2018 when the Company has estimated completion, less the $78.42 million CN estimate inflated to 2016, I calculate a $51.58 million cost overrun for Monticello spent fuel storage capital costs.

Q. What is Xcel's proposed rate recovery for Monticello spent fuel storage capital costs included in this rate case?

A. In response to Department information request no. 2122 part A,[63] the Company requested a $19.4 million capital addition for 2016 and a $48.7 million capital addition for 2018, for a total of $68.1 million on a total company basis.

Q. Have you already proposed an adjustment earlier in your testimony related to the Monticello spent fuel storage, specifically for cask no. 16?

A. Yes. I recommended that it would not be reasonable to recover $15.1 million in capital costs from ratepayers since the Company did not properly oversee the vendor,

[62] DOC Ex. ___ at NAC-32 (Campbell Direct).
[63] DOC Ex. ___ NAC-33 (Campbell Direct).

which resulted in the weld issue that has caused $15.1 million in additional capital costs.

Q. To avoid double-counting your adjustment for the weld issue in the Monticello spent fuel storage capital costs that exceed the amount in the 2005 certificate of need, what do you recommend?

A. I recommend decreasing the cost overrun amount of $51.58 million over the approved CN amount by the $15.1 million adjustment already recommended for Monticello cask no. 16, which results in $36.48 million excluded from Monticello capital costs for spent fuel storage on a total company basis, or $26.79 million on a Minnesota jurisdictional basis. Below is the specific rate recovery reduction by year on a total company and Minnesota jurisdictional basis for Monticello spent fuel storage capital costs using Department information request no. 2122 Part A:

DOC Table 20: Monticello Spent Fuel Storage Capital Additions Adjusted

($ millions)	2016	2017	2018	2019	2020
Total Co.	$0[64]	$0	($36.48)[65]	$0	$0
MN Juris.	**$0**	**$0**	**($26.79)**[66]	**$0**	**$0**

Q. Why do you recommend excluding the $36.48 million total company or $26.79 Minnesota jurisdictional for Monticello spent fuel storage capital costs?

[64] Per Department information request no. 2122 part A, the only capital addition in 2016 is for the PI cask no. 16, which I already adjusted earlier.

[65] As noted in Department information request no. 2122 part A, the capital addition for 2018 is $48.7 on a total company basis, of which I recommended that $30.1 be excluded based on my adjustment.

[66] As noted in the Energy Supply O&M section, the Company's response to Department information request no. 198 part a, shows a 73.45% Minnesota jurisdictional allocator.

A. I make this recommendation based on the ratemaking policy of holding utilities accountable to the project costs that the utility represents to the Commission in regulatory proceedings (*e.g.*, certificates of need). While utilities have the opportunity to show that recovery of costs above that amount are reasonable, it needs to be clear that the burden of proof is on the utility to show why any cost overruns should be charged to ratepayers. This approach is consistent with Minnesota Statute section 216B.16, subd. 4.

To complete this review, the Department recommends that the nuclear consultants authorized by the Commission review the costs that exceed the current-year costs of the amounts authorized in the certificates of need for Prairie Island also review the reasons for the cost overruns at the Monticello facility of $36.48 million total company or $26.79 million Minnesota jurisdictional before the Commission grants rate recovery of these Monticello spent fuel storage capital costs. Based on input from the consultant's review, the Commission can decide what level of rate recovery is reasonable.

XX. SPENT FUEL FOR PRAIRIE ISLAND (PI)

Q. What amount was approved for PI spent fuel storage?

A. In Xcel's initial petition in Docket No. E002/CN-08-510 on page 13 of Company witness Mr. Lee Samson's Direct Testimony, the Company estimated total costs of $155.7 million in 2008 dollars for construction, casks, licensing, re-licensing, and regulatory fees for PI spent fuel storage capital costs.

In response to Department information request no. 2123 Attachment A in this rate case, Xcel indicated that $69.6 million of the 2008 CN capital cost expenditures were for casks no. 48 to 64 for the time period 2022 to 2031. Therefore the adjusted CN amount that Xcel proposes to recover in this proceeding for PI spent fuel storage costs through the 2020 test year is $86.1 million in capital cost expenditures ($155.7 million less $69.6 million).

Q. What would be the escalated amount of the 2008 figures in today's 2016 dollars?

A. As noted above, the Company provided in response to Department information request no. 91 in Docket No. E002/RP-15-21 (Xcel's 2015 Integrated Resource Planning)[67] that the inflation rate assumed for spent fuel storage by the Company was 3% per year. As a result, the $86.1 million in 2008 dollars (for PI spent fuel storage capital costs for 2008 to 2020) inflated by 3% per year results in $109.07 million capital cost expenditures in 2016 dollars for construction, casks, licensing, re-licensing, and regulatory fees for PI spent fuel storage capital costs (net of capital cost expenditures were for casks no. 48 to 64 for the time period 2022 to 2031).

Q. What amount of costs has the Company incurred and does it expect to incur through 2020 for PI spent fuel storage capital costs?

A. According to the Company's response to Department information request no. 2123,[68] Attachment A, line U, the Company's actual capital costs from 2005 to 2014 plus budgeted costs included in the test years for 2016 to 2020 is $147.2 million ($323.8 million for all costs through 2031 less $176.6 million for costs during 2022 to 2031).

[67] DOC Ex. ___ at NAC-31 (Campbell Direct).
[68] DOC Ex. ___ at NAC-32 (Campbell Direct).

Q. What amount of these costs will exceed the CN estimate for PI spent fuel storage capital costs?

A. Using the $147.2 million figure provided by the Company in actual costs and costs budgeted in the current rate case through 2020, less the $109.07 million CN estimate inflated to 2016, the net results in a $38.13 million cost overrun for PI spent fuel storage capital costs.

Q. What treatment do you recommend for the $38.13 million in higher capital costs for PI spent fuel storage in this rate case?

A. Until Xcel can show why it is reasonable to charge ratepayers for these higher costs, I recommend that cost recovery be limited to the current-dollar amount Xcel proposed in its CN.

Q. Why do you recommend excluding the $38.13 million Total Company or $28.01 Minnesota jurisdictional for PI spent fuel storage capital costs?

A. Similar to the cost overrun for the Monticello storage costs, the purpose of this proposal is to ensure that the rates charged to Xcel's ratepayers are reasonable, which is a requirement in Minnesota Statute section 216B.03. To assist in this determination, the Department recommends that the nuclear consultants authorized by the Commission review the reasons why the $38.13 million in higher costs occurred before the Commission grants rate recovery of these PI spent fuel storage capital costs. The consultant's review is intended to assist the Commission in deciding the appropriate level of rate recovery.

Q. Under your proposal, would Xcel be able to recover all of the costs for Prairie Island that the Commission determines are reasonable?

A. Yes. It is certainly the Department's intention that Xcel would fully recover all costs of both the Prairie Island and Monticello nuclear power plants that the Commission determines are reasonable to charge to ratepayers.

Q. How does your proposal affect the proposed revenue requirements in the rate case at this time?

A. Table 21 below provides the specific rate recovery reduction by year on a total company and Minnesota jurisdictional basis for PI spent fuel storage capital costs additions using Xcel's response to Department information request no. 2122, part A[69]. As shown in this table, there are no adjustments in 2016, 2017 or 2018; the adjustment occurs in 2019 with a small adjustment in 2020.

DOC Table 21: PI Spent Fuel Storage Capital Additions Adjusted

($ millions)	2016	2017	2018	2019	2020
Total Co.	$0	$0	$0	($37.949) [70]	($0.181)
MN Juris.	$0	$0	$0	($27.874)[71]	($0.133)

XXI. PI CAPITAL COSTS IN EXCESS OF ESTIMATES PROVIDED IN 2008 CNs

Q. What did the Commission state regarding the prudency of Prairie Island Life Cycle Management (LCM) costs?

69 DOC Ex. ___ NAC-33 (Campbell Direct).
70 The total capital addition for PI spent fuel storage is $41.3 million for 2018.
71 As noted in the Energy Supply O&M section, the Company response to Department information request no. 198 part a, shows a 73.45% Minnesota jurisdictional allocator.

A. The Commission in its December 22, 2015 Notice of and Order for Hearing (December 22, 2015 Order) in the current rate case Docket No. E-002/GR-15-826, on page 3, issue no. 8, identified as a two-prong LCM cost issue to be addressed in the rate case, as follows:

> Whether, in light of the following factors, the amounts authorized for cost recovery in the 2016 test year and the 2017 and 2018 plan years should be considered provisional or placeholder amounts until the Commission makes a determination on the prudency of the Life Cycle Management costs at the Prairie Island plant:
>
> a) Xcel's pending submission of a Nuclear Scope Study in its January 29, 2016 supplemental comments in its resource plan, docket E-002/RP-15-21; and
> b) The possibility that there will not be adequate time to fully investigate and determine the prudence of these costs in this rate case.

Q. Did the Commission in its December 22, 2015 Order require the Company to provide additional supplemental information in this rate case regarding the prudency of expenditures for the PI LCM?

A. Yes. On page 4 of the Commission's December 22, 2015 Order, the Commission required the following supplemental filings from the Company:

> To expedite record development on the prudence of Company expenditures on the Life Cycle Management program at its Prairie Island nuclear plant, the Company will be required to file, no later than January 29, 2016, supplemental schedules and testimony that:
>
> 1) Describe and compare projected and actual Life Cycle Management costs (and, to the extent relevant, Extended Power Uprate costs) from 2008 through 2020 by generating unit and year, including the proposed 2016 test year in this rate case, and the 2017 and 2018 plan years. The descriptions and comparisons should include all changes and updates to projected costs from 2008 on and should include all cites to relevant

certificate of need, resource plan, and general rate case dockets.

2) Compare the relevant parts of the proposed 2016 test year, the 2017 plan year, and the 2018 plan year to the proposed five-year capital budget in the Company's pending resource plan, docket E-002/RP-15-21.

Q. Based on the Company's indication that it projects PI capital costs to exceed earlier estimates by $600 to $900 million between 2021 and 2034 according to its 2015 integrated resource plan (IRP), what was the Commission's recommended action?

A. On page 3 of the Commission's April 15, 2016 Order in both the current rate case and 2015 IRP (Docket Nos. E-002/GR-15-826 & E-002/RP-15-21) the Commission recommended thorough investigation of all projected Prairie Island costs along with specialized, technical assistance through the following action:

> The Commission concurs with the Department and the Company that thorough analysis of all projected Prairie Island costs is critical to a fair and reasonable outcome in both the resource-plan and rate-case dockets. In the resource-plan case, determining the probable level of these costs is critical to determining the most cost-effective resource mix for Xcel through 2034, including the most reasonable role in that mix for Sherco 1 and Sherco 2. In the general rate-case docket, determining the probable level, prudence, and reasonableness of these costs is critical to setting just and reasonable rates.
>
> The Commission will therefore ask the Commissioner of Commerce to seek authority from the Commissioner of Management and Budget to incur costs for specialized technical professional investigative services under Minn. Stat. § 216B.62, subd. 8, to investigate and verify the statements made by Xcel concerning Xcel's Prairie Island projected costs. The costs for the technical assistance are assessed to the utility.

Q. On page 2 of his Supplemental Testimony, Mr. O'Connor indicated that many of the plant systems at PI were only intended to operate for the initial 40 years of the Units' operating license. What did the Department do to investigate this statement for ratemaking purposes? :

A. The Department issued discovery asking why Xcel did not include in its cost estimates for its 2008 Prairie Island certificates of need *all* of the capital costs needed to replace nuclear systems. This information is important to ensure that Xcel provided the Commission the relevant information needed to determine whether the life extension was reasonable and appropriate. In response to Department information request no. 1160,[72] the Company provided the following:

> The Company understands this question to be asking about the capital costs provided in Docket Nos. E-002/CN-08-509 and E-002/CN-08-510, concerning the Company's applications for an Extended Power Uprate (EPU) and for additional dry cask storage at the Prairie Island nuclear plant. The focus of those applications were the EPU and dry cask storage projects for which Certificates of Need were required. However, the Company understood in 2008 that many of the Prairie Island plant systems would need to be addressed after the end of the initial 40-year life. Therefore the Company provided general LCM cost projections, based on the information available at that time, for context and to address the impacts of continued operations. These capital cost estimates represented a high-level, long-range forecast for addressing LCM issues over the course of the plant's remaining life, based on then current knowledge. The Company did not attempt to present, nor would it have been feasible to provide, detailed, granular forecasts for capital costs to run a two-unit nuclear plant for an additional 26 years.
>
> The determination of what aging plant systems will need to be replaced or refurbished, at what time, and at what specific cost over the course of a 20-year life extension depends in large part on how those systems actually age

[72] DOC Ex. ___ NAC-34 (Campbell Direct).

over time. The Company, therefore, could not have identified in the Certificate of Need Application all projects that would ultimately be needed to extend the life of Prairie Island. Instead, the Company explained that the plant had been experiencing capital costs of approximately $20 million per year for basic reliability efforts (which was typical of the industry at that time), and that it anticipated future annual maintenance along those same lines. Certificates of Need Application at pages 4-6 to 4-7, Docket Nos. E002/CN-08-509 and E002/CN-08-510 (May 16, 2008).

The Company also noted that it anticipated a number of larger projects, including replacement of the Unit 2 steam generator at a projected cost of $259 million (in then-current dollars). However, the Company did not attempt to identify all specific systems replacements that would be required, and noted that its larger LCM project estimate of $600 million was an estimate that was based on additional assumptions regarding certain work that would be completed in conjunction with the EPU. Certificates of Need Application at pages 1-9 to 1-10 and 4-7, Docket Nos. E002/CN-08-509 and E002/CN-08-510.

As discussed in Mr. O'Connor's Direct and Supplemental Direct Testimony in this proceeding and in the Company's recent filings in the 2015 Integrated Resource Plan, certain assumptions have changed in the intervening eight years, including the extent and cost of LCM work to be completed. In particular, the costs and requirements for capital work at nuclear facilities have increased significantly since 2008 and 2012 in light of industry changes and NRC regulation. Additionally, the cancellation of the EPU impacted when and how certain aging systems were to be addressed, as Mr. Weatherby discusses in his Supplemental Direct Testimony. The Company has kept the Commission updated as to these changes, including the specific LCM projects completed and the associated costs of those projects, through its 2012 Change in Circumstances filings, the 2008, 2010, 2012, 2013, and 2015 rate cases, and its 2015 Integrated Resource Plan.

Q. What is your understanding of the PI 2008 CN's discussed above?

A. My understanding is that the estimated costs provided for the projects requested in the 2008 CNs represented the total costs estimated at that time for the Company to continue to operate PI plant, including $20 million per year for reliability projects. For example, Xcel stated in the Docket No. E002/CN-08-501 preceding that its proposal to extend the lives of the Prairie Island power plants was “least-cost.” In order to determine if it was cost effective to go ahead with the EPU/LCM and spent fuel casks storage, compared to selecting other generation or demand response projects, all costs for running the PI nuclear plant needed to be provided to, and considered by, the Commission at the time it evaluated whether to approve the 2008 CNs. Clearly, without sufficient information to allow consideration of the total cost of a requested project, the Commission would have been unable to compare the relative costs and merits of alternative projects or actions.

In addition, Xcel stated the following in Appendix H of its initial filing in that case, which appears to contradict Xcel’s statements in the current case:

> The NRC license renewal process requires a significant review of the plant and its processes to assure safety margins consistent with the current licensing basis are maintained during the period of the renewed license. The license renewal process is described here to provide context for the review done by the NRC. The plant operates under a license issued by the NRC. The NRC is limited to issuing initial operating licenses to commercial nuclear power reactors for a period of 40 years. **The 40-year initial license period was based on the typical depreciation period for a large industrial facility. It was not based on any physical limitations inherent in commercial nuclear power reactors**. Industry studies were initiated in the 1980s to evaluate the feasibility of operating commercial nuclear power reactors beyond the initial 40-year period. Two plants were reviewed as part of initial DOE/EPRI studies (one of which was the Xcel’s Monticello plant). **These studies concluded that commercial nuclear power reactors could safely operate well beyond the initial license period**. As a result, the

> NRC entered into rulemaking to establish a regulatory process for renewing operating licenses. The resulting license renewal regulations allow for an operating license to be renewed in 20-year increments. (Emphasis added)

Xcel's certificate of need application for additional dry cask storage, Appendix H, page H-3.

Q. What did the two 2008 Prairie Island CN's address?

A. Xcel received one certificate of need for an extended power uprate (EPU) (Docket No. E002/CN-08-509) and received the second certificate of need to increase the dry cask storage for spent fuel waste from the units (Docket No. E002/CN-08-510). Xcel later sought and received approval to terminate the extended power uprate project; however, the increase in storage capacity was necessary to extend the operating lives (LCM project) of the two PI units at the plant from 2013/2014 to 2033/2034 even without the extended power uprate.

Q. According to the Company's April 1, 2009 petition regarding authorizing additional dry cask storage at PI in Docket No. CN-08-510, what did the Company provide to the Commission regarding necessary capital costs for the life extension period?

A. The Company provided the below information regarding necessary capital costs for the 20-year life extension period of PI.

1) Page 14 of Charles Bomberger's Direct Testimony stated the following:

> Q. WHAT MAGNITUDE OF CAPITAL IMPROVEMENTS DO YOU ESTIMATE WILL BE NECESSARY TO OPERATE PRAIRIE ISLAND SAFELY AND EFFICIENTLY THROUGH THE LIFE EXTENSION PERIOD?
>
> A. We included $20 million annually in ongoing capital and another $600 million (2008 to 2034) to address life cycle management projects (including steam generator replacement on Unit 2) and dry fuel storage that are

> necessary to support twenty additional years of operation. These investments were included in our Strategist simulations as described in Ms. Engelking and Mr. Wishart's testimony.

2) Pages 10-11 of Steven Wishart's Direct Testimony provided the following:

> **Q. WERE ADDITIONAL OPERATING COSTS INCLUDED IN THE CASE INVOLVING THE CONTINUED OPERATION OF PRAIRIE ISLAND?**
> A. Yes. We included $20 million annually for routine capital improvements and an additional $600 million in capital investments to account for a number of larger capital projects that would need to be undertaken. Mr. Bomberger discusses how we determined these costs in his testimony.

Q. Did the Commission's February 27, 2013 Order in Docket No. E002/CN-08-509 approve any change in the Company's CN cost amounts?

A. No. The Commission's Order simply approved Xcel's proposed termination of the extended power uprate for PI and did not approve any change in Company's CN capital cost amounts. The order noted that:

> Neither the Department nor the OAG opposed rescinding Xcel's Certificate of Need prospectively. But these parties cautioned the Commission, in issuing such an order, to refrain from ruling on the prudence of Xcel's expenditures to date…

Further, the order stated:

> Finally, the Commission clarifies that its decision to terminate Xcel's Certificate of Need does not address Xcel's resource needs… Nor does the decision address the prudence of Xcel's investments or the recovery of those costs…

Q. What increases in capital costs does the Company now estimate that impact both the current rate case and 2015 IRP?

A. In its 2015 Integrated Resource Planning filing, in the short time between January and October 2015, Xcel estimated costs of Prairie Island increased by $175 million, for the period 2016 to 2020. Xcel also indicated that its capital costs for the period 2021 to 2034 may increase by another $600 million to $900 million.

Q. In Xcel's current rate case filing, did the Company request recovery of the increase in capital costs for PI of $175 million for 2016 to 2020?

A. Yes. Xcel includes a $175 million increase in capital costs for PI for 2016 to 2020 (Company's five-year rate plan). However, the Company broke the $175 million increase in PI capital cost into $90 million assigned to the PI LCM and $84 million related to regulatory mandates. Mr. Weatherby discussed costs increases in costs in his Supplemental Direct Testimony on pages 31-33, while Mr. O'Connor in his Supplemental Direct Testimony described these mandated projects on his Schedule 8. Xcel proposes to allow recovery of all costs that the Company has represented to be "regulatory mandates."

Q. What is your perspective on the Company splitting the $175 increase in capital costs between the PI LCM and PI mandated capital projects?

A. Since Xcel chose to abandon the EPU for PI, it is necessary to ensure that Xcel's assignment of costs to these the LCM and EPU efforts is reasonable. Further, Xcel needs to show that the decisions the Company made regarding the LCM were reasonable. I recommend that the nuclear consultants review these PI mandated capital costs to determine if Xcel's proposed cost allocation is reasonable.

In addition, it is important to examine whether Xcel accurately identified costs as "mandated" since Xcel proposes to exclude these costs from what the Company considers to be the PI LCM capital costs.

Further, as noted above, it was the Department's understanding at the time of the 2008 CNs that all PI capital costs were included in the CN cost estimate above for the PI life extension for the Commission to consider relative to the total costs and merits of other alternatives. Thus, it is important to review the reasonableness Xcel's assertions at that time that the LCM was least-cost.

Q. Where does Xcel show the differences between 1) 2008 CN, 2) 2012 Change in Circumstance, and 3) actual costs through September 2015 plus costs rate case 2016- 2020?

A. Mr. Weatherby's Schedule 2 provides that information.

Q. Did the Department issue discovery asking the Company to update Mr. Weatherby's Schedule 2 with all PI LCM capital costs?

A. Yes. In Department information request no. 1163[73] I asked the Company to update to 2015 actuals, provide escalation rates used, explain differences in 3 categories, and updated with all PI capital LCM costs for 2008 to 2020.[74] The Company

[73] DOC Ex. ___ NAC-35 (Campbell Direct).
[74] The Company's Attachment B provides the 2012 to 2034 (end of license life capital costs) the Department will address these years in its comments to Xcel's 2015 IRP.

provided the yearly amounts on their Attachment A which excluded the Mandates capital costs and I have summarized as follows:

DOC Table 22: PI LCM Capital Costs with Mandates Excluded

($ millions)	2008-2015 A	2016-2020 TY	2008-2020
2008 CN	$643.3	$131.3	$774.6
2012 CIC*	$665.7	$257.4	$923.2
Rate Case	$613.4	$346.8	$960.2
2008 CN less Rate Case	$29.9	**($215.5)**	($185.6)
2012 CIC less Rate Case	$52.3	($89.4)	($37.0)

*"CIC" refers to "changed circumstances".

Q. Do you recommend that the Commission use the information in Table 22 for determining the cap on PI capital costs?

A. No, at least not at this time. The nuclear consultants should review the mandated capital costs to determine if it would be reasonable for such costs to be excluded, rather than pre-determining as part of this rate case that the costs of the mandates should be excluded as recommended by the Company. That is, the Company's classification of costs should be reviewed for reasonableness. This further review is needed since, as indicated in Table 22 above, the "2008 CN less the Rate Case" amount of $215.5 million reduction in capital cost expenditures for this rate case represents the amount by which Xcel's Prairie Island costs exceed the amounts Xcel indicated in its 2008 CN as being "least-cost."

Q. Did you issue discovery asking the Company to update Mr. Weatherby's Schedule 2 to include all PI capital costs?

A. Yes. In Department information request no. 1164[75] I asked the Company to update to 2015 actuals, provide escalation rates used, explain differences in 3 categories, and updated with all PI capital costs for 2008 to 2020.[76] The Company provided the yearly amounts on their Attachment A and I have summarized as follows (excluding spent fuel storage (SFS) and Extended Power Uprate (EPU) capital costs since SFS was address above in separate adjustments by the Department and PI EPU was addressed in Xcel last rate case):

DOC Table 23: PI Capital Costs with Spent Fuel Storage & Extended Power Uprate Capital Costs Excluded

($ millions)	2008-2015 A	2016-2020 TY	2008-2020
2008 CN	$674.2	$131.3	$805.4
2012 CIC	$841.5	$265.6	$1107
Rate Case	$864	$433.9	$1,297.8
2008 CN less Rate Case	($189.8)	**($302.6)**	($492.4)
2012 CIC less Rate Case	($22.5))	($168.3))	($190.8)

Q. Do you recommend the Commission use the above table for determining the placeholder amount for recovery of PI capital costs for purposes of this rate case?

A. Yes. As noted above, until the nuclear consultants review the mandated capital costs to determine if Xcel showed it is reasonable that they be excluded and the Commission considers that information, I recommend that the mandated capital costs be included in the calculation of PI capital costs and that this total PI capital cost figure be used to determine the cost overrun amount (the projected cost above the costs estimated as part of the 2008 PI LCM CN).

[75] DOC Ex. ___ NAC-36 (Campbell Direct).

[76] The Company's Attachment B provides the 2012 to 2034 (end of license life capital costs) the Department will address these years in its comments to Xcel's 2015 IRP.

Additionally, I recommend that the Commission base its determination of the amount of cost overruns on comparing the actual costs to the original 2008 PI LCM CN, when the Commission granted Xcel's proposal to extend the PI life. I do not recommend that the Commission accept Xcel's proposal to base the determination of the cost overrun amount on the Company's representation of costs in 2012, since that was not when the decision to pursue the LCM and EPU was made.

As a result I recommend comparing actual costs to the "2008 CN less the Rate Case" amount of $302.6 million in determining the placeholder amount for the reduction in capital cost expenditures for this rate case. These costs reflect the total amount of costs over the CN cap. Use of the "2008 CN less the Rate Case" amount is most consistent with the language of the Commission's February 27, 2013 order cited above.

Q. How did you calculate your adjustment for the PI capital costs using the $302.6 million reduction in capital expenditures discussed above?

A. I started with Mr. O'Connor's Supplemental Direct Testimony. His Schedule 1 page 1 of 3 shows the 2016 to 2020 capital additions (by year and in total) for PI for Reliability and Improvement capital projects of $386,105,076 ($381,403,241 plus $4,701,835). The $386,105,076 (2016-2020 test years) PI capital costs for reliability and improvement <u>less</u> the $302,600,000 capital costs over the CN level, results in a $83,505,076 amount allowed for recovery in the rate case until the Commission is able to determine the reasonable level of PI costs to recover in rates. I recommend that consideration of whether Xcel has demonstrated the reasonableness of recovering more than $83,505,076 for PI LCM be deferred until the nuclear consultants have a reasonable opportunity to review the reasonableness of the$302,600,000 amount that exceeds the CN amounts. The table below shows the PI capital additions by 2016 to 2020 test years from Mr. O'Connor's Schedule 1, and my resulting recommended adjustments for PI capital costs over the CN amounts in current dollars, which begins in 2017 through 2020.

DOC Table 24: PI Capital Cost Adjustment over 2008 CN Cap

($ millions)	2016	2017	2018	2019	2020
Rate Case	$48.665	$63.859	$151.169	$52.479	$69.932
DOC adj.	**($0)**	**($29.019)**	**($151.169)**	**($52.479)**	**($69.932)**

XXII. SUMMARY OF RECOMMENDATIONS

Q. Please summarize your recommendations.

A. My specific recommended adjustments are listed below. The financial effects of these recommendations are included in the schedules of DOC Witness Mr. Lusti's Direct Testimony.

<u>**Depreciation Expense Adjustments Based on Approved Remaining Lives Study:**</u>

The depreciation expense adjustments for the 2016 to 2020 test years, to reflect the changes in remaining lives depreciation approved by the Commission are as follows:

DOC Table 1: Depreciation Expense Adjustments for Approved RL Depreciation

($ in 000's)	2016	2017	2018	2019	2020
Depreciation Expense	($9,787)	($9,916)	($13,201)	($18,880)	($21,332)
Total Revenue Requirements	($8,046)	($7,618)	($9,777)	($13,727)	($14,703)

Mankato Energy Center II In-Service Date:

The resulting adjustment for this rate case by changing the in-service date for Mankato II from January 1, 2018 to June 1, 2019 was provided in response to Department information request no. 131[77] on Attachment A, the Company provided the below adjustments for capacity costs due to the change in the Mankato II in-service date from January 1, 2018 to June 1, 2019. While I agree with the Company's adjustments for 2018 and 2019, the Company did not provide any information to support its increase in capacity costs for 2020, and as a result, the Department assumed $0 impact for 2020, instead of $111,000 as noted by the Company. In other words, the Company has not demonstrated the reasonableness of its support for its proposed increase in capacity costs for 2020.

DOC Table 2: Mankato II Energy Center Adjustment Due to Change to In-Service Date

($ in 000's)	2016	2017	2018	2019	2020
Capacity Expense	$0	$0	($23,071)	($9,483)	$131
Xcel's Total Revenue Requirements	$0	$0	($19,411)	($7,979)	$111
DOC's Total Revenue Requirements	$0	$0	($19,411)	($7,979)	$0

Protecting Americans from Tax Hikes Act of 2015:

The resulting tax adjustments and overall impact as a result of the 2015 PATH Act were provided by the Company on page 5 of the supplemental response to XLI information request no. 35, the below 2016 to 2020 tax adjustments and resulting overall impact:

[77] DOC Ex. ___ at NAC-3 (Campbell Direct).

Please see Attachments F and G to this response for bridge schedules that include all adjustments related to the PATH Act of 2015 for the 2019 and 2020 forecast years, respectively. Please note that the Bonus Tax Depreciation and Federal R&E Credit adjustments are shown in columns (2) and (3) of each page, but the impact of Secondary Calculations, especially the NOL calculation in column (6), are needed to fully illustrate the incremental impact.

$ millions	2016 Test Year	2017 Plan Year	2018 Plan Year	2019 Forecast	2020 Forecast	Total
Base Rate revenue requirement impact, cumulative	$(5.4)	$13.3	$4.7	$(9.2)	$(19.9)	
incremental	$(5.4)	$18.7	$(8.6)	$(13.9)	$(10.7)	$(19.9)

State of Minnesota, Electric Jurisdiction

The impact on the five year forecast is summarized below.

$ millions	2016 Test Year	2017 Plan Year	2018 Plan Year	2019 Forecast	2020 Forecast	Total
Burdick Sch. 13	$194.6	$246.7	$297.1	$379.6	$427.7	
PATH Act update	$(5.4)	$13.3	$4.7	$(9.2)	$(19.9)	
Updated cumulative forecast	$189.2	$260.0	$301.8	$370.4	$407.8	
incremental	$189.2	$70.8	$41.8	$68.6	$37.4	$407.8

State of Minnesota, Electric Jurisdiction

Accumulated Deferred Income Tax Pro-rate:

The below table provides the ADIT revenue requirement impacts for 2016 to 2020 as shown in adjustment A-38 on page A38-6:

DOC Table 3: Summary of ADIT Prorate Adjustment by the Company in Revenue Requirements

ADIT Adj A38 ($ in 000's)	2016	2017	2018	2019	2020
Requested ROE	$6,483	$1,896	$1,813	$1,357	($0,207)

I recommend the following regarding the prorated ADIT issue:

- First, if Xcel continues to contest this issue, I recommend that the Company be required to get its own IRS private tax ruling before any change to ADIT is allowed for ratemaking purposes that will harm ratepayers;

- Second, the Commission could consider whether allowing forecasted test years continues to be reasonable when related benefits such as ADIT are not being provided to ratepayers in a consistent manner. In other words, ratepayers continue to pay 100 percent of the deferred taxes while receiving only a prorated ADIT offset to rate base;
- Third, at a minimum, the Commission should limit the use of a prorated ADIT balance for the current forecasted test year but require a true-up to actual or non-prorated ADIT balances the following year (consistent with the majority of MISO and PJM transmission owners, consistent with the FERC's recommendation in Docket No. ER16-197 and consistent with Pricewaterhouse Coopers article on "Tax Insights from US Power & Utilities");
- Fourth, since Xcel's proposed ADIT changes will harm ratepayers and change the way ratemaking is handling accelerated depreciation for rate cases without demonstrating adequate support to show that the ADIT change is required under the Internal Revenue Code or Treasury Regulations (only supported by private letter rulings that are entity specific), because Xcel failed to meet its burden of proof to show its proposed change to be reasonable, and because the Company failed to provide the adjustment the Department requested for the ADIT issue as discussed above, I recommend that no ADIT changes be allowed in this rate case at this time.

State of Minnesota Research and Experimentation Tax Credits:

I recommend that the Minnesota R&E adjustment be set at the average 2012 to 2014 unadjusted actual amounts provided on the Minnesota tax forms of $828,290 instead of the Company's recommended $559,000 based on 2011 to 2013 actuals with adjustments. The resulting adjustment is the difference between the Department's recommended $828,290 and Company's recommended average Minnesota R&E Tax Credits of $559,000 included in the test year, or an increase in Minnesota R&E Tax Credits of $269,290 for 2016 to 2020 test years.

Additionally, I discuss below that 73.5% of the North Dakota Investment Tax Credit should be assigned to the Minnesota jurisdiction. If the Commission approves this recommendation, I generally conclude that the Minnesota R& E tax credit should also be assigned based on the 73.5% instead of 100%, although I note that there is also a North Dakota R&E tax credit that the Company needs to address as discussed below.

As a result, assuming that the Commission approves my recommendation below that 73.5% of the North Dakota Investment Tax Credit should be assigned the Minnesota jurisdiction, my above adjustment would be reduced to $197,928 ($269,290 * 73.5%).

North Dakota Investment Tax Credit:

For consistency and easy of application, I recommend that all taxes be assigned to Minnesota jurisdiction based on the 73.5% allocator which is used to assign all generation and transmission plant to Minnesota. In other words since Minnesota ratepayers pay for generation and transmission plant using a consolidated 73.5%

allocator, all taxes should also be assigned to Minnesota jurisdiction using the same 73.5% in order to be equitable. This recommendation for taxes would avoid the picking and choosing by the Company for which tax is assigned to Minnesota. This means that NDITC, ND R&E (which the Company needs to address) and MN R&E would be assigned to Minnesota using the 73.5% allocator.

At a minimum, I would recommend a ($737,119) reduction for 2020 for the NDITC assigned to Minnesota jurisdiction. Because of some the uncertainty of tax amounts, a true-up for the NDITC in the RES Rider, like the Company does for the Production Tax Credit true-up may be appropriate.

Additionally, the Company should provide the ND R&E credit amounts on a Total Company and Minnesota Jurisdictional basis for 2016 to 2020 test years. The Company should also provide all calculations to show the impact of my recommendation that all taxes (expenses and credits) should be assigned to Minnesota using a 73.5% jurisdictional allocator.

<u>Energy Supply Operating and Maintenance (O&M) Expenses:</u>

Based on my review of Energy Supply O&M costs, because these costs are up and down for 2012 to 2015 actual amounts, and because the 2016 test year amounts were 8.9% increase over 2015 actuals, I recommend a 4-year average using 2012 to 2015 actual amounts for setting rates for 2016 test year and I would propose the same adjustment for all test years 2016 to 2020 as shown below:

DOC Table 7: DOC Recommended Adjustments for Energy Supply O&M Expense

($ in millions)	2016	2017	2018	2019	2020	2012-2015 average
MN Jurisdictional[78]	$120.9	$123.9	$126.8	$125.4	$129.0	$115.375
DOC Adjustment	$5.525	$5.525	$5.525	$5.525	$5.525	

<u>Other Energy Supply O&M – Courtenay Wind:</u>

I recommend the following adjustments to Other Energy Supply O&M expenses to remove the Courtenay Wind land lease amounts incorrectly included in the rate case to avoid double recovery:

- $1.2 million reduction for 2017;
- $1.205 million reduction for 2018;
- $1.210 million reduction for 2019; and
- $1.215 million reduction for 2020.

<u>Nuclear Non-Outage O&M Expenses:</u>

I recommend basing rates on a three-year average of 2013 to 2015 actual costs. Comparing this three-year average of $273.1 million to the Company's 2016 test year amount of $281.3 million results in a downward adjustment of $8.2 million for nuclear non-outage O&M expenses on a total company basis. I assumed the same 73.45% Minnesota jurisdictional allocator that I used for Energy Supply O&M expenses,[79] which results in a $6.023 million downward adjustment to nuclear non-

[78] I assumed a 73.45% Minnesota jurisdictional allocator based on the Company response to Department information request no. 198 part a (DOC Ex.___NAC-15 (Campbell Direct).

[79] The Company response to Department information request no. 198 part a, shows a 73.45% Minnesota jurisdictional allocator.

outage O&M expenses on a Minnesota jurisdictional basis for all test years 2016 to 2020.

Allocation – Transco Costs:

Below shows the 2014 and 2015 amortization of Transco costs on a Minnesota Jurisdictional basis. I note that the 2014 Transco costs are already included in the rate case through adjustment A34 and the 2015 Transco costs is my recommended additional adjustment for Transco cost amortization credit for Minnesota ratepayers.

2014 Transco Costs MN Jurisdictional	**Annual Amortization 3-year Rate Plan**	**Annual Amortization 5-year Rate Plan**
$138,450	$46,150	$27,690

2015 Transco Costs MN Jurisdictional	**Annual Amortization 3-year Rate Plan**	**Annual Amortization 5-year Rate Plan**
$181,975	$60,658	$36,395

Allocation – Service Company Costs:

I recommend the following expense adjustments to reflect the New Labor Ratio for Rates and Regulation Service Function for 2016 to 2018 test years:

	2016	2017	2018
Rates & Regulation Service	($255,734)	($261,996)	($269,077)

Since the Company did not provide the expense adjustments for 2019 and 2020, I estimated the 2019 and 2020 expense adjustment to reflect the New Labor Ratio for Rates and Regulation Service Function based on the average increase of 2.6% for 2016 to 2018, which results in an adjustment of ($276,073) for 2019 and ($283,251) for 2020.

<u>Health and Welfare and Benefits Expenses</u>:

I recommend that the Company's increase for health and welfare expense for 2016 to 2018 be limited to a 4.3% increase (instead of the Company's proposed 7.9% increase for 2016, 5.3% for 2017 and 5.8% for 2018), based on the average year-over-year increases actually experienced by the Company from 2011 to 2015. This recommended 4.3% increase includes the relatively high increase from 2013 and 2014, but also the much lower increases in the other years. My recommended adjustments for 2016 to 2018 health and welfare expense are as follows:

- $1.410 million reduction for 2016;
- $1.873 million reduction for 2017; and
- $2.602 million reduction for 2018.

I recommend a 1% average increase for overall pension and benefits expenses for 2019 and 2020 test years, instead of the 2.5% increase proposed by the Company.

DOC Table 13: DOC Recommended Adjustments for Overall Pension & Benefits Expenses for 2019 and 2020

($ in millions)	2018 TY	2019 TY	2020 TY
Co. Requested	$76.195	$78.1	$80.053
DOC Recomm.	$73.593[80]	$74.329	$75.072
DOC Adjust. 1%		($3.771)	($4.981)

[80] Company recommended $76.195 million less the $2.602 million DOC adjustment for health and welfare for 2018.

401 Nicollet Mall Building Lease:

I used the net adjustments for 2016 to 2018 and then determined the 2019 and 2020 levels based on a percent of increase trend. I recommend the following adjustment to normalize the lease expenses and remove the moving expenses:

DOC Table 14: Normalization of Leases and Remove Moving Expenses

($ in 000s)	2016	2017	2018	2019	2020
DOC adj	($506)	($632)[81]	($759)	($844)	($941)

Non-Asset Based Trading:

Since the actual 2012 to 2015 O&M expenses continued to increase, I recommend that the O&M expense level for the most recent year 2015 of $1,565,027 be used for setting 2016 test year credit for O&M expenses for non-asset based trading. For 2017 to 2018 plan years, I recommend using the same escalation rates calculated above for 2017 and 2018, plus the average increase for 2019 and 2020. The below table I show my recommended adjustment for 2016 to 2020 O&M expense credit for non-asset based trading (note that this is only the O&M portion, which makes up the majority of the total credit):

DOC Table 16: DOC Adjustment for O&M Expenses for Non-Asset Based Trading

	2016	2017	2018	2019	2020
Co Req.	$967,621	$990,186	$1,013,476	$1,037,314	$1,061,713
DOC Rec.	$1,565,027	$1,601,523	$1,639,192	$1,667,748	$1,706,975
DOC Adj.	($597,406)	($611,337)	($625,716)	($630,434)	($645,262)

[81] I noted a 2.5% increase from 2016 to 2017 and a 20% from 2017 to 2018, and therefore I assumed an 11.25% average increase.

Prairie Island Settlement Payment:

I conclude that it is not appropriate to escalate the Settlement Agreement costs above the $2.5 million statutory cap. Under the Settlement Agreement the Company is only paying $2.5 million per year. In addition, I note that this is an example supporting why a generic escalation of all O&M costs for 2017 and 2018 is not appropriate.

I recommend the following adjustments to exclude the escalation factor and assumed increases above the $2.5 million statutory cap.

- $28,416 decrease in nuclear expense for 2017;
- $61,929 decrease in nuclear expense for 2018;
- $101,495[82] decrease in nuclear expense of 2019; and
- $148,183[83] decrease in nuclear expense of 2020.

PI Fire Protection Program In-Service Date:

The resulting Minnesota jurisdictional revenue requirements adjustments for 2016 to 2018 based on moving the PI Fire Protection Program for the 2016 capital addition of $18.6 million from a November 2016 in-service date to the January 2017 in-service date I recommend are as follows, with Xcel's proposed revenue requirement for 2016 decreasing and the revenue requirements for the subsequent four years increasing somewhat to reflect the higher levels of rate base in those years compared to the assumed levels in Xcel's proposed rates.

[82] $33,513 incremental 2017 increase * 118% = $39,566 plus $61,929 (2018 cumulative amount).
[83] $39,566 incremental 2018 increase * 118% = $46,688 plus $101,495 (2019 cumulative amount).

DOC Table 18: Revenue Requirement Impact of Fire Protection Program Change to In-Service Date

($ in 000's)	2016	2017	2018	2019	2020
MN rev req	($2,969)[84]	$380	$573	$500	$404

I would like the Company to address in Rebuttal Testimony:

- why the 2017 to 2020 capital additions for the Fire Protection Program should not be moved back one year, based on Xcel's current expectations as to NRC approval and the Department's recommended later in-service date, for November 2016 capital additions to move to January 2017, and
- the revenue requirement calculations for moving the 2017 to 2020 capital additions for the Fire Protection Program back one-year, including exclusion of the 2020 capital additions (the last year of the MYRP).

<u>**Monticello Dry Fuel Storage (DFS) Load Cask No. 16, Increased Capital Costs:**</u>

I recommend that the increase in capital costs of $15.1 million ($19.4 million less $4.3 million) for Monticello cask no. 16 due to the weld not being done correctly by the vendor and not correctly supervised by Xcel not be recovered from ratepayers. The NRC noted in its letter that it is the licensee's responsibility to oversee vendors, and Xcel did not oversee the vendor performing the welding for casks no. 11 to 16.

[84] By email the Company indicated that because of the Construction Work in Progress (CWIP) balance, the plant receives a return for all of 2017 and depreciation was recorded for 11 ½ months for 2017.

DOC Table 19: Revenue Requirement Impact of Removing $15.1 Million in Capital Costs for Monticello Cask # 16

($ in 000's)	2016	2017	2018	2019	2020
MN rev req	($640)	($1,475)	($1,422)	($1,368)	($1,318)

<u>Spent Fuel Storage for Monticello:</u>

I recommend decreasing the capital cost overrun amount of $51.58 million over the approved CN amount by the $15.1 million adjustment already recommended for Monticello cask no. 16, which results in $36.48 million excluded from Monticello capital costs for spent fuel storage on a total company basis, or $26.79 million on a Minnesota jurisdictional basis. I recommend the nuclear consultants authorized by the Commission review why the $26.79 million in higher costs above the approved CN amount occurred before the Commission grants rate recovery of these Monticello spent fuel storage capital costs. Below is the specific rate recovery reduction by year on a total company and Minnesota jurisdictional basis for Monticello spent fuel storage capital costs using Department information request no. 2122 Part A:

DOC Table 20: Monticello Spent Fuel Storage Capital Additions Adjusted

($ millions)	2016	2017	2018	2019	2020
Total Co.	$0[85]	$0	($36.48)[86]	$0	$0
MN Juris.	**$0**	**$0**	**($26.79)**[87]	**$0**	**$0**

[85] Per Department information request no. 2122 part A, the only capital addition in 2016 is for the PI cask no. 16, which I already adjusted earlier.

[86] As noted in Department information request no. 2122 part A, the capital addition for 2018 is $48.7 on a total company basis, of which I recommended that $30.1 be excluded based on my adjustment.

[87] As noted in the Energy Supply O&M section, the Company's response to Department information request no. 198 part a, shows a 73.45% Minnesota jurisdictional allocator.

Spent Fuel for PI:

I recommend that the nuclear consultants authorized by the Commission review the reasons why the $38.13 million in higher costs above the approved CN amount occurred before the Commission grants rate recovery of these PI spent fuel storage capital costs. The consultant's review is intended to assist the Commission in deciding the appropriate level of rate recovery.

DOC Table 21: PI Spent Fuel Storage Capital Additions Adjusted

($ millions)	2016	2017	2018	2019	2020
Total Co.	$0	$0	$0	($37.949) [88]	($0.181)
MN Juris.	$0	$0	$0	($27.874)[89]	($0.133)

PI Capital Costs in Excess of Estimates Provided in 2008 CNS :

I recommend that until the nuclear consultants review the mandated capital costs to determine if Xcel showed it is reasonable that they be excluded and the Commission considers that information, I recommend that the mandated capital costs be included in the calculation of PI capital costs and that this total PI capital cost figure be used to determine the cost overrun amount (the projected cost above the costs estimated as part of the 2008 PI LCM CN).

Additionally, I recommend that the Commission base its determination of the amount of cost overruns on comparing the actual costs to the original 2008 PI LCM CN, when the Commission granted Xcel's proposal to extend the PI life. I do not recommend that the Commission accept Xcel's proposal to base the determination of

[88] The total capital addition for PI spent fuel storage is $41.3 million for 2018.
[89] As noted in the Energy Supply O&M section, the Company response to Department information request no. 198 part a, shows a 73.45% Minnesota jurisdictional allocator.

the cost overrun amount on the Company's representation of costs in 2012, since that was not when the decision to pursue the LCM and EPU was made.

As a result I recommend comparing actual costs to the "2008 CN less the Rate Case" amount, resulting in $302.6 million as the reduction in capital cost expenditures for this rate case. These costs reflect the total amount of costs over the CN cap. Use of the "2008 CN less the Rate Case" amount is most consistent with the language of the Commission's February 27, 2013 order cited above.

DOC Table 24: PI Capital Cost Adjustment over 2008 CN Cap

($ millions)	2016	2017	2018	2019	2020
Rate Case	$48.665	$63.859	$151.169	$52.479	$69.932
DOC adj.	**($0)**	**($29.019)**	**($151.169)**	**($52.479)**	**($69.932)**

Q. Does this conclude your Direct Testimony?

A. Yes.