Direct Testimony and Schedules
Benjamin C. Halama

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in North Dakota

Case No. PU-20-____
Exhibit___(BCH-1)

Overall Revenue Requirements
Rate Base
Income Statement

November 6, 2020

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Benjamin C. Halama. I am Manager of Revenue Analysis for Xcel Energy Services Inc. (XES or the Service Company), the service company for Xcel Energy, Inc. and its operating company subsidiaries.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have over five years of experience at XES, supporting Northern States Power Company–Minnesota (NSPM or the Company) in the areas of regulatory accounting, financial operations, and revenue requirements. In my current role, I am responsible for the development of jurisdictional revenue requirements for all NSPM jurisdictions. My resume is provided as Exhibit___(BCH-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I support the Company's financial data and our requests for a general rate increase and interim rate increase for the State of North Dakota retail electric jurisdiction, specifically:

- the overall retail revenue requirement of $228.644 million and revenue deficiency of $22.228 million, determined by the cost of service for the 2021 test year; and
- the interim increase of $16.358 million as discussed in our Alternative Petition for Interim Rates.

I relied on and incorporated information provided by other witnesses in this proceeding to develop many of the test year revenue requirement adjustments discussed in my testimony. My testimony includes several schedules with financial information related to the 2021 test year revenue requirements and deficiency. These schedules were prepared by me or under my supervision. Exhibit___(BCH-1), Schedule 2 provides an index of the schedules to my testimony.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized into the following sections:

- Section II Case Overview
- Section III Supporting Information
- Section IV Rate Base
- Section V Income Statement
- Section VI Utility and Jurisdictional Allocations
- Section VII Annual Adjustments to the Test Year
- Section VIII Compliance Issues and Applications
- Section IX Conclusion

II. CASE OVERVIEW

A. Test-Year Revenue Requirements and Deficiency

Q. WHAT IS THE AMOUNT OF THE TEST YEAR REVENUE REQUIREMENT FOR THE COMPANY'S ELECTRIC OPERATIONS IN ITS NORTH DAKOTA JURISDICTION?

A. The 2021 test year jurisdictional retail revenue requirement for North Dakota electric utility operations is $228.644 million based on forecasted average rate base and projected net operating income for the 2021 test year, based on a 7.35 percent overall Rate of Return (ROR) recommended by Company Witness Mr. Dylan W. D'Ascendis in his Direct Testimony.

Q. WHAT IS THE AMOUNT OF THE REVENUE DEFICIENCY FOR THE TEST YEAR?

A. The revenue deficiency for the test year is $22.228 million. A summary of the revenue deficiency for 2021 is shown in Exhibit___(BCH-1), Schedule 7. Schedule 7 is a comparison of the jurisdictional revenue requirement amount for the test year with the forecasted revenues for the same period under present rates, which were approved by the Commission in Case No. PU-12-813. The level of North Dakota retail electric rates must be increased by this amount in 2021 for the Company to have an opportunity to earn an overall return on rate base of 7.35 percent as shown in Exhibit___(BCH-1), Schedule 3A.

Q. WHAT IS THE PERCENTAGE INCREASE IN OVERALL ELECTRIC RETAIL REVENUES PROPOSED IN THIS CASE?

A. The test year revenue deficiency amount represents a 10.8 percent overall increase in retail revenues compared to projected 2021 retail revenues at present rates.

Q. HOW DID YOU CALCULATE THE DEFICIENCY?

A. The 2021 revenue requirements for this filing are calculated by including all revenues and costs at the proposed capital structure, as well as any federal and state credits earned on a total company basis, then allocating those components to North Dakota based on the allocation methods discussed in Section VI. This produces an all-in revenue requirement of the jurisdiction. This presentation allows rider projects to be removed from the base rate request and ensure no double recovery of cost since the applicable costs and revenues are removed with no impact to the test year deficiency. Rider removals are discussed in more detail in Section VII.D of my testimony.

Q. DID YOU PREPARE A COST OF SERVICE STUDY THAT SUPPORTS THE REVENUE REQUIREMENT AMOUNT AND REVENUE DEFICIENCY FOR THE TEST YEAR?

A. Yes. Under my direction, a cost of service study was prepared. Exhibit___(BCH-1), Schedule 3A contains a copy of the jurisdictional cost of service study for the test year.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CAPITAL STRUCTURE AND WHAT ARE THE VARIOUS COMPONENTS?

A. The capital structure employed in this case represents the Company's 2021 budgeted amounts. The costs and ratios associated with this capital structure are found in Exhibit___(BCH-1), Schedule 3A, and are as follows:

	Rate	Ratio	Weighted Cost
Long Term Debt	4.22%	46.96%	1.98%
Short Term Debt	1.00%	0.54%	0.01%
Common Equity	10.20%	52.50%	5.36%
Weighted Cost			7.35%

Company Witness Mr. Dylan W. D'Ascendis discusses the Company's capital structure in further detail in his Direct Testimony.

B. Case Drivers

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. I discuss the drivers of this rate case when compared to existing rates. I first discuss capital related cost drivers, then amortizations driving the test year revenue requirement, then tax related cost drivers, then O&M related cost drivers, and conclude with other margin related drivers.

Q. WHAT IS YOUR COMPARISON YEAR IN DESCRIBING COST CHANGES?

A. Consistent with the analysis provided in prior rate cases, my explanation of the key deficiency cost drivers uses a comparison to the Commission ordered results from our last electric rate case (Case No. PU-12-813) which used a test year based on the 2013 budget. I will refer to the comparison year as the 2013 test year. I have also provided a comparison to the 2019 actual year as filed in the Jurisdictional Annual Report (JAR) on May 1, 2020 (2019 actual year) in Case No. 20-185.

Q. WHY ARE YOU COMPARING TO 2019 ACTUAL YEAR?

A. As stated above, the 2019 actual year was filed in the JAR on May 1, 2020 and that filing showed a small refund to customers. The Company is providing a comparison to 2019 actual to address changes in the Cost of Service Study (COSS). Further, given the passage of time since the Commission last set base rates – and the multiple settlements and other revenue impacting actions that have occurred since 2013 – providing a comparison point to actual costs of the Company, represented in the JAR using 2019 Actual data helps to clarify the Company's need for additional revenue at this time.

I note that the comparison to the JAR has not been changed even though the calculation of actual earnings in the 2019 Actual JAR is under consideration by the Commission in Case No. PU-18-155, where the Company noted costs associated with certain Purchase Power Agreements (PPAs) were omitted. However, because these are Fuel Cost Rider (FCR) related items, they do not materially impact the comparisons that the Company is presenting, nor do they lessen the Company's need for additional revenue at this time.

Q. WHAT ARE THE MAJOR DRIVERS OF THE COMPANY'S NEED FOR RATE RELIEF?

A. A summary of the cost elements to which the revenue deficiency can be attributed is provided in Exhibit___(BCH-1), Schedule 9. The major cost elements driving the revenue deficiency are identified in Table 1 below.

Table 1

Net Deficiency ($ in millions)

	Increase (Decrease) 2021 TY to 2013 TY	Increase (Decrease) 2021 TY to 2019 Actual
Capital and Capital Related	$54.3	$22.0
Amortizations	6.0	7.4
Taxes	(13.8)	(7.8)
Operating Expense	6.6	7.5
Other Margin Impacts	(31.6)	(6.9)
Total Net Incremental Deficiency	$21.4	$22.3

Q. WHY ARE THE DEFICIENCIES IN TABLE 1 NOT EQUAL TO EACH OTHER?

A. Table 1 above shows the incremental deficiencies as compared to the 2013 test year and the 2019 actual year. Since the comparison point is two different time periods the incremental deficiencies are not equal. However, as I discussed above, the 2021 test year deficiency is $22.228 million.

1) Capital Related Cost Drivers

Q. PLEASE DESCRIBE THE REVENUE REQUIREMENT IMPACT FOR THE PRINCIPAL CHANGES IN CAPITAL AND CAPITAL RELATED COSTS.

A. Table 2 below compares the test year forecast revenue requirements with the revenue requirements for the 2013 test year and 2019 actual year, by category, for capital plant related costs as shown on Schedule 9, Detailed Case Drivers.

Table 2

Capital and Capital Related Revenue Requirements Changes

($ in millions)

	Increase (Decrease) 2021 TY to 2013 TY	Increase (Decrease) 2021 TY to 2019 Actual
Nuclear	$8.3	$(0.0)
Nuclear Decommissioning Trust	2.0	2.0
Steam	0.3	0.2
Remaining Life Adjustment	3.4	3.4
Wind	17.4	11.8
All Other Production	0.8	0.4
Transmission	6.6	1.0
Distribution	6.5	1.6
General and Intangible	7.2	1.0
DTA (Federal Credits & NOL)	1.1	1.0
Other Rate Base	0.6	(0.5)
TOTAL Capital and Capital Related	$54.3	$22.0

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN NUCLEAR CAPITAL COSTS.

A. The 2021 test year revenue requirements include a $8.3 million increase due to Nuclear capital related investments when compared to the 2013 test year. Company Witness Mr. Mark P. Moeller discusses the Company's key nuclear investments in his Direct Testimony.

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN NUCLEAR DECOMMISSIONING TRUST CAPITAL COSTS.

A. The 2021 test year revenue requirements include a $2.0 million increase related to the Nuclear Decommissioning Trust (NDT) when compared to the 2013 test year and 2019 actual year. Additional information regarding the NDT is provided by Mr. Moeller.

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN THE REMAINING LIFE ADJUSTMENT.

A. The 2021 test year revenue requirements include a $3.4 million increase related to a change in remaining life for production facilities, primarily Sherco 1 and 2 compared to the 2013 test year and 2019 actual year. Additional information regarding the remaining life change is provided in the Direct Testimony of Mr. Moeller; Company Witness Mr. Christopher J. Shaw discusses the prudence of adjusting the retirement date for these units in his Direct Testimony.

Q. WHAT ARE THE PRINCIPAL CHANGES IN WIND CAPITAL COSTS?

A. The 2021 test year revenue requirements include a $17.4 million and $11.8 million increase related to our wind investments compared to the 2013 test year and 2019 actual year, respectively. This increase is due to capital investments for the Blazing Star I & II, Crowned Ridge, Mower, Jeffers, and Community Wind North Wind Farms, which are scheduled to be placed in service in 2020. In addition, we anticipate rolling into base rates the Border, Courtenay, Foxtail, Blazing Star I and II, Lake Benton and Crowned Ridge Wind Farms. The increase compared to 2019 actual year is smaller due to a partial year of revenue requirements for Foxtail, Blazing Star I and Lake Benton Wind Farms which were placed in service in 2019. The increase in Wind capital costs is offset by rider revenue and PTC credits included in the COSS as discussed above and in detail in Section VII.D below. These investments, and the Commission's issuance of Advanced Determinations of Prudence (ADP) for them, are discussed in the by Mr. Moeller.

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN TRANSMISSION CAPITAL COSTS.

A. The 2021 test year revenue requirements include a $6.6 million and $1.0 million increase due to Transmission capital investments when compared to the 2013 test year and 2019 actual year, respectively. The increase compared to the 2013 test year is due mainly to the roll-in of transmission capital projects which were in service by the end of 2020, particularly the CapX2020 projects from the Transmission Cost Recovery (TCR) Rider. The increase compared to the 2019 actual year is due to the Huntley-Wilmarth transmission project and other smaller investments in the long-term reliability of the transmission system. The increase in transmission capital costs is partially offset in rider revenue included in the COSS for rider eligible projects as discussed above and in detail in Section VII.D below. Mr. Moeller discusses these transmission investments further in this Direct Testimony.

Q. PLEASE IDENTIFY THE PRINCIPAL CHANGES IN DISTRIBUTION CAPITAL COSTS.

A. The 2021 test year revenue requirements include a $6.5 million and $1.6 million increase due the Distribution business unit's capital investments in North Dakota compared to the 2013 test year and 2019 actual year, respectively. This increase is due to capital investments relating to expansion of Distribution's asset health programs to address the portions of our system that are closest to our customers, such as pole and underground cable replacements. Distribution also manages work associated with our Advanced Grid Intelligence & Security (AGIS) initiative. Additional information regarding distribution's capital investments is provided in the Direct Testimony of Company witness Ms. Kelly A. Bloch.

Q. WHAT ARE THE PRINCIPAL CHANGES IN GENERAL & INTANGIBLE CAPITAL COSTS?

A. The 2013 test year revenue requirements include a $7.2 million and $1.0 million increase to due to our investments in capital projects classified as General & Intangible compared to the 2013 test year and 2019 actual year, respectively. This increase is mainly driven by investments in replacing aging technology. The increase compared to the 2013 test year is driven by the Company's investments in its new General Ledger and Work and Asset Management programs. Mr. Moeller discusses these key technology investments further in this Direct Testimony.

2) Amortizations

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN AMORTIZATIONS.

A. The test year revenue requirements include a $6.0 million and $7.4 million increase related to amortizations compared to the 2013 test year and 2019 actual year, respectively. This increase is primarily due to new amortizations for RER PTC Amortization (discussed in adjustment 9 below) and PI EPU Recovery (discussed in adjustment 7 below), as well as an increase in Rate Case Expense amortization. The increase compared to the 2013 test year is also due to a new amortization for the Net Operating Loss (NOL) Tax Reform Regulatory Amortization (discussed in adjustment 13 below). The increase due to RER PTC Amortization is offset by rider revenue and PTC credits included in the COSS as discussed above and in detail in Section VII.D below.

3) Taxes

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN TAXES.

A. The test year revenue requirements include a $13.8 million and $7.8 million decrease due to taxes compared to the 2013 test year and 2019 actual year, respectively. This decrease is driven by increased amounts of Production Tax Credits (PTCs) associated with new and existing wind farms being moved to base rate recovery in this case. The decrease compared to the 2013 test year is also due to a decrease in the federal income tax rate from 35 percent to 21 percent effective January 1, 2018 with the enactment of the Tax Cuts and Jobs Act (TCJA). These items are partially offset by an increase in property taxes. The increase in PTCs is offset by the rider revenue included in the COSS as discussed above.

4) O&M

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN O&M COSTS.

A. Table 3 below compares the test year forecast revenue requirements with the revenue requirements for the 2013 test year and 2019 actual year, by category, for operating expenses as shown on Schedule 9, Detailed Case Drivers.

Table 3

O&M Cost Changes ($ in millions)

	Increase (Decrease) 2021 TY to 2013 TY	Increase (Decrease) 2021 TY to 2019 Actual
Nuclear	($1.0)	($0.4)
Steam	(2.9)	(0.8)
Wind	2.8	1.9
Purchased Demand	(0.3)	1.9
All Other Production	(0.4)	0.3
Transmission	0.0	0.2
Transmission Interchange	3.5	0.1
Distribution	1.8	2.0
Regional Markets	0.7	0.0
Customer Accounting / Info / Service	(0.3)	0.6
A&G	2.8	1.7
TOTAL O&M	$6.6	$7.5

Q. WHAT ARE THE REASONS FOR THE CHANGE IN NUCLEAR, STEAM AND WIND OPERATING EXPENSE?

A. The 2021 test year revenue requirements include a net decrease of $1.1 million and a net increase of $0.7 million in nuclear, steam and wind operating expenses compared to the 2013 test year and 2019 actual year, respectively. This change is due to an increase in wind O&M associated with placing into service new wind farms that have been or will be added to our generation portfolio. The wind O&M increase is fully offset when compared to the 2013 test year and partially offset when compared to the 2019 actual year by a reduction in nuclear outage costs and reduced overhaul and project investments as several coal units approach retirement. The wind O&M increase is further offset by rider revenue included in the COSS as discussed above.

Q. WHAT ARE THE REASONS FOR THE INCREASE IN PURCHASED DEMAND OPERATING EXPENSE?

A. The 2021 test year revenue requirements include a $1.9 million increase in purchased demand operating expenses compared to the 2019 actual year. The increase is due to an increase in overall contracted capacity due to a new contract with Manitoba Hydro that increased the capacity purchases by 125 MW starting in 2021. The Commission granted an ADP for this PPA, including the increased capacity in 2021, in Case No. PU-12-070. Purchased Demand costs are also driven by the PPA for the MEC II facility which commenced service in June 2019.

Q. WHAT ARE THE REASONS FOR THE INCREASE IN TRANSMISSION INTERCHANGE OPERATING EXPENSE?

A. The test year revenue requirements include a $3.5 million increase in transmission interchange operating expenses compared to the 2013 test year. This increase is primarily due to the addition of the Wisconsin portion of the CAPX2020 La Crosse Project transmission line in 2014 for which the Commission granted an ADP in Case No. PU-09-678 and the La Crosse - Madison 345 kV transmission line in December 2018, which is further described by Mr. Moeller. I note that, because these capital projects are located in Wisconsin and owned by the Company's sister company, Northern States Power Company – Wisconsin, they are not included in rate base but are, rather, recovered through the Interchange Agreement and therefore recorded as an O&M expense.

Q. What are the reasons for the increase in distribution operating expense?

A. The 2021 test year revenue requirements include a $1.8 million and $2.0 million increase in distribution operating expenses compared to the 2013 test year and the 2019 actual year, respectively. This increase is due to increased O&M to implement the AGIS initiative, increased vegetation management costs, and increased labor costs due to filling certain North Dakota based distribution positions. Additional information regarding distribution O&M is discussed by Ms. Bloch.

Q. What are the reasons for the increase in Administrative and General (A&G) expense?

A. The 2021 test year revenue requirements include a $2.8 million and $1.7 million increase in A&G expense compared to the 2013 test year and 2019 actual year, respectively. The increase when compared to 2013, and to a lesser extent when compared to the 2019 actual year, is primarily driven by the O&M associated with our investments in new information technology by our Business Systems business area. Specifically, we are incurring O&M expense increases for Application Development & Maintenance services, increased Software and Hardware licensing, and maintenance to support the capital assets built as a result of business demand. There is also an increase in employee benefits due to higher active healthcare costs.

In addition, the Company received an unusually large insurance distribution in 2019. Nuclear Electric Insurance Limited (NEIL), which is a mutual insurer providing the Company's nuclear accidental outage insurance and nuclear property damage insurance, declared a distribution of $700 million to its policyholder owners in 2019 in response to better than expected underwriting and a 16.8 percent return on its investments. Of that $700 million, Xcel Energy received approximately $11 million, of which $0.7 million is jurisdictionally allocated to North Dakota. In its 2019 Annual Report, NEIL stated that the 2019 distribution was the largest distribution to policyholders made in the last 19 years. The NEIL distribution creates an unusually large credit against O&M expenses in 2019, lowering our overall cost of service in 2019. However, this distribution from NEIL is a one-time event and, because it is not recurring, will not be available to mitigate revenue needs in the test year.

5) Other Margin

Q. PLEASE DESCRIBE THE REVENUE REQUIREMENT IMPACT FOR THE PRINCIPAL CHANGES IN OTHER MARGIN.

A. Table 4 below compares the test year forecast revenue requirements with the revenue requirements for the 2013 test year and 2019 actual year, by category, for other margin as shown on Schedule 9, Detailed Case Drivers.

Table 4

Net Deficiency ($ in millions)

	Increase (Decrease) 2021 TY to 2013 TY	Increase (Decrease) 2021 TY to 2019 Actual
Sales Change	$4.9	$2.7
Net Settlement Revenue	(15.7)	
Rider Revenue	(20.2)	(13.3)
15 CBED and 7 Solar PPAs		2.6
Other	(0.7)	1.1
TOTAL Other Margin Impacts	($31.6)	($6.9)

Q. PLEASE DESCRIBE HOW CHANGES IN SALES IMPACT THE COMPANY'S REVENUE REQUIREMENTS.

A. From 2010 to 2019, North Dakota weather-normalized retail sales have decreased by an average of 0.1 percent per year. Xcel Energy has been experiencing a historic decrease in North Dakota retail sales attributable to the COVID-19 pandemic and is forecasting a 2.6 percent decrease in 2020 sales compared to 2019. For 2021, the Company is forecasting a 0.5 percent annual increase in North Dakota retail sales, which would represent a partial recovery of lost sales since 2019. Company Witness Ms. Jannell Marks supports the Company's sales forecast and sales data in her Direct Testimony. In light of lower sales, which reduces revenue earned by the Company under current rates, the Company requires increased revenue to offset the impact of the decline in sales volume.

Q. ARE THERE ANY OTHER MARGIN ITEMS WITH A SIGNIFICANT IMPACT ON THE 2021 REVENUE DEFICIENCY?

A. Yes. The 2021 test year revenue requirements include a $19.6 million increase in base rate revenue due to the 2014 and 2015 increases from the settlement in the last rate case, partially offset by DOE settlement revenue in the 2013 test year and not in the 2021 test year. As noted above, for the rider eligible cost increases there is a corresponding increase in rider revenue included in the COSS. The increase is $20.2 million and $13.3 million compared to the 2013 test year and 2019 actual year, respectively.

Q. WHAT IS THE 15 CBED AND 7 SOLAR PPAS INCREASE IN OTHER MARGIN?

A. The Commission has ordered the Company to exclude certain PPAs from the Company's FCR mechanism. In the 2019 JAR, the Company included the expense for these PPAs in the calculation of weather-normalized earnings because including all PPA costs has been the methodology the Company has historically used, as well as the method specifically defined in the earnings sharing provision (Section A.2) of the Revised Second Amended Settlement approved in February 2014 in Case No. PU-12-813. However, for purposes of our COSS, those costs need to be removed to prevent base rate recovery for these items. The Company has made an adjustment so that the FCR revenue and PPA costs related to the 15 CBED and 7 Solar resources offset. Therefore, our rate request does not reflect our recovery of these resources. This adjustment results in a variance compared to the 2019 actual year.

Q. ARE THE FUNCTIONAL CLASS CATEGORIES OF OPERATING EXPENSE COMPARABLE BETWEEN THE 2021 TEST YEAR FORECAST AND THOSE CONTAINED IN 2013 RATE CASE TEST YEAR?

A. Yes. Both categorizations conform to the FERC Uniform System of Accounts.

III. SUPPORTING INFORMATION

Q. WHAT TOPICS DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section, I provide information related to data provided in our application, the selection of the test year and the jurisdictional cost of service study (JCOSS).

A. Data Provided and Selection of Test Year

Q. PLEASE DEFINE THE FISCAL PERIODS FOR WHICH FINANCIAL DATA IS PROVIDED IN THIS PROCEEDING.

A. Financial data is provided for the most recent fiscal year (calendar year 2019), the current year (calendar year 2020 – forecasted from June 30, 2020), and the test year (calendar year 2021). Financial data for the most recent fiscal year, the current year and the test year are adjusted for traditional regulatory adjustments (*e.g.*, advertising expenses, association dues, etc.).

Q. WHY DID THE COMPANY PROPOSE CALENDAR YEAR 2021 FOR THE TEST YEAR FOR THIS PROCEEDING?

A. Calendar year 2021 was selected as the test year because it uses the most recent available budget information and is a reasonable representation of the costs and expenses the Company will incur when interim and final rates take effect.

Q. DOES THE 2021 FUTURE TEST YEAR MEET THE COMMISSION'S REQUIREMENTS?

A. Yes. The use of a future test year is permitted by North Dakota Century Code (N.D.C.C.) § 49-05-04.1(1), which allows a utility to select a future test year. N.D.C.C. § 49-05-04.1(2) then requires the Company to present:

a) a comparison of forecast data to historical period data to demonstrate the reliability and accuracy of the utility's forecast, including a comparison of the prior years' forecast or budgeted data to actual data for those periods;

b) a statement that the test-year budget data is reasonable, reliable, and made in good faith; and all basic assumptions used in making or supporting the forecast are reasonable, evaluated, identified, and justified to allow the Commission to test the appropriateness of the forecast; and

c) the accounting treatment applied to anticipated events and transactions in the budget is the same as the accounting treatment to be applied in recording the events once they have occurred.

Schedule 10 to my Direct Testimony provides a comparison of past budgets to actual costs from 2017-2019 in compliance with the first requirement of this statute. The 2021 Company budget data, after the adjustments I discuss below, is a reasonable representation of the costs and expenses the Company will incur to provide electric service in the State of North Dakota and complies with N.D.C.C. § 49-05-04.1(2). Thus, the 2021 test-year data is reasonable, reliable and made in good faith, and is appropriate for setting rates in this proceeding. In addition, the accounting treatment applied to anticipated events and transactions in the budget is the same as the accounting treatment applied in recording the events once they have occurred.

Q. N.D.C.C. § 49-05-04.1(2)(c) REQUIRES A UTILITY TO FILE CERTAIN FINANCIAL DATA FOR COMPARISON WITH THE TEST YEAR DATA. IS THE COMPANY COMPLYING WITH THIS REQUIREMENT?

A. Yes. Exhibit___(BCH-1), Schedule 3C is the Company's 2019 actual jurisdictional cost of service study. This information, providing the most recent calendar year of actual data, is consistent with the approach we took in our last two electric rate cases (Case No. PU-10-657 and Case No. PU-12-813), and with the financial statements in our May 1, 2020 jurisdictional annual report filed with the Commission in Case No. 20-185. Exhibit ___ (BCH-1), Schedule 3B provides the same information in comparison to the 2020 current year as required by the North Dakota Century Code.

B. Jurisdictional Cost of Service Study

Q. PLEASE DESCRIBE THE COMPONENTS OF THE JURISDICTIONAL COST OF SERVICE STUDY FOR THE 2021 TEST YEAR.

A. The complete jurisdictional cost of service study for 2021 is provided in Exhibit___(BCH-1), Schedule 3A, 2021 Test Year Cost of Service Study and includes all the adjustments discussed in my Direct Testimony.

The jurisdictional cost of service study includes the following financial data input sections for both total Company and the North Dakota Jurisdiction: (i) capital structure; (ii) cost of capital; (iii) income tax rates; (iv) rate base; (v) income statement; (vi) income tax calculations; and (vii) cash working capital computation.

Q. PLEASE DESCRIBE THE JURISDICTIONAL COST OF SERVICE SCHEDULES.

A. The jurisdictional cost of service summary for the 2021 test year is included in Schedule 3A:

- The "Rate Base Summary" for total Company electric operations and the North Dakota jurisdiction is shown on Schedule 3A, Page 1.
- An "Income Statement Summary" for total Company electric operations and the North Dakota jurisdiction is shown on Schedule 3A, Page 2.
- The "Income Tax Summary" for total Company electric operations and the North Dakota jurisdiction is shown on Schedule 3A, Page 3. The schedule shows adjustments to book income necessary to determine state and federal taxable income. The federal and state income tax calculations are carried back to the income statement on Schedule 3A, Page 2.
- The "Revenue Requirement Summary" for total Company electric operations and the North Dakota jurisdiction is shown on Schedule 3A, Page 4. Specifically, the schedule shows: (i) the earned overall rate of

return on rate base; (ii) the earned ROE; (iii) the base rate revenue deficiency that needs to be recovered to enable North Dakota jurisdiction electric operations to earn the requested ROE; and (iv) the total revenue requirements.

- The computation of cash working capital is shown on Exhibit___(BCH-1), Schedule 8 and is carried back to the rate base on Schedule 3A, Page 1.

Q. THE COMPANY IS NOT RECOVERING CERTAIN COSTS THROUGH THE FCR, WHAT DOES THAT DO TO THE 2021 DEFICIENCY?

A. There is no impact to the 2021 test year deficiency for the 15 CBED and 7 Solar resources that have been excluded from the FCR. An adjustment has been made to the COSS so that the FCR revenue and PPA costs related to the 15 CBED and 7 Solar resources offset. This means that the COSS assumes no recovery of those costs. This does result in a variance when compared to the 2019 actual year JAR as discussed in Section II.B above.

Q. ARE THE REVENUE CONVERSION FACTOR CALCULATION AND THE NORTH DAKOTA COMPOSITE INCOME TAX RATES INCLUDED IN THIS FILING?

A. Yes. The revenue conversion factor is the incremental amount of gross revenue required to generate an additional dollar of operating income. See Table 5 below for the revenue conversion factor calculation.

Table 5

Revenue Conversion Factor Calculation

Gross Revenue Factor =	1 / (1 - Federal and ND Income Tax)
	1 / (1 - 0.24405)
	1.32284

Q. WHAT FEDERAL CORPORATE TAX RATE WAS USED TO CALCULATE THE REVENUE CONVERSION FACTOR?

A. Pursuant to the TCJA signed by President Trump on December 22, 2017, the Company has used a federal corporate tax rate of 21 percent in the calculation of the revenue conversion factor. The revenue conversion factor and composite income tax rates are included in Schedule 3A, Page 1.

Q. PLEASE EXPLAIN HOW THE INTEREST DEDUCTION FOR DETERMINING TAXABLE INCOME IS CALCULATED.

A. The interest deduction applicable to the income tax calculation is the result of a calculation commonly referred to as "interest synchronization." The amount of interest deducted for income tax purposes is the weighted cost of debt capital multiplied by the average rate base.

Q. DESCRIBE THE SCHEDULE IN YOUR EXHIBITS THAT IS RELATED TO THE INCOME STATEMENT.

A. Exhibit___(BCH-1), Schedule 11 consists of comparative income statements for the test year. Schedule 11, Page 1 is a comparative income statement for the 2021 test year, showing the income effect of present authorized rates and proposed rates. This comparative income statement was prepared from the results of the JCOSS and includes the revenue deficiency in the North Dakota Jurisdiction electric utility operations. Schedule 11, Page 2 shows an electric utility comparative income statement for the North Dakota jurisdiction and total Company for the 2021 test year, before and after making test period adjustments.

IV. RATE BASE COMPONENTS

Q. PLEASE EXPLAIN WHAT RATE BASE REPRESENTS.

A. Rate base primarily reflects the capital investment made by a utility in plant, equipment, materials, supplies, and other assets necessary for the provision of utility service, reduced by accumulated depreciation and non-investor sources of capital, such as deferred taxes.

Q. PLEASE IDENTIFY THE MAJOR COMPONENTS OF THE PROJECTED TEST YEAR RATE BASE.

A. The test year rate base is generally composed of the following major items, which will be described in further detail later in my testimony:

- Net Utility Plant;
- Short-term Construction Work in Progress (CWIP);
- Accumulated Deferred Income Taxes (ADIT); and
- Other Rate Base Items.

Q. PLEASE DESCRIBE THE SCHEDULES IN YOUR TESTIMONY THAT ARE RELATED TO THE TEST YEAR AVERAGE INVESTMENT IN RATE BASE.

A. Exhibit___(BCH-1), Schedule 15, Page 1 of 3, shows a detailed statement of the Average Rate Base by component for the 2021 test year. Schedule 15, Page

2 of 3, is a comparative statement of the 2021 Test Year Average Rate Base for the North Dakota jurisdiction and total Company, before and after making proposed test period adjustments. Schedule 15, page 3 of 3 provides detailed information on CWIP and ADIT for the total Company and North Dakota jurisdiction. Exhibit___(BCH-1), Schedule 3C, Page 1 shows the Company's actual 2019 Average Rate Base as provided in the May 1, 2020 jurisdictional annual report to the Commission. The annual jurisdictional report rate base provided in Schedule 3C has been modified to include the proposed capital structure, rider removals, cash working capital, and a redetermination of the deferred tax assets.

A. Net Utility Plant

Q. WHAT DOES NET UTILITY PLANT REPRESENT?

A. Net utility plant represents the Company's investment in plant and equipment that is used and useful in providing retail electric service to its customers, net of accumulated depreciation and amortization.

Q. PLEASE EXPLAIN THE METHOD USED TO CALCULATE NET UTILITY PLANT INVESTMENT IN THIS CASE.

A. The net utility plant is included in rate base at depreciated original cost reflecting the simple average of projected net plant balances at the beginning and end of the test year. Such treatment is consistent with the method employed in our most recent North Dakota electric rate case.

Q. WHAT HISTORICAL BASE DID THE COMPANY RELY ON AS A STARTING POINT TO DEVELOP THE PROJECTED NET PLANT BALANCES FOR THE BEGINNING OF THE TEST YEAR?

A. The historical base used was the Company's actual net investment (Plant In Service less Accumulated Depreciation) on the books and records of the Company as of June 30, 2020. The budget projections for July through December 2020 were then applied to the June 30, 2020 balance to arrive at a beginning test year net plant balance.

Q. ON WHAT BASIS WERE NET PLANT BALANCES PROJECTED FOR THE END OF THE TEST YEAR?

A. The ending net plant balances were determined by applying the data contained in the 2021 capital budget to the above-described beginning test year balances, adjusted for plant additions, retirements, depreciation, salvage and removal costs projected to occur during the test year. The net plant balance in rate base reflects the simple average of projected net plant balances at the beginning and end of the 2021 test year. Such treatment is consistent with the method employed in the Company's most recent electric rate case.

Q. WHAT WAS THE AVERAGE NET UTILITY PLANT INCLUDED IN THE TEST YEAR RATE BASE?

A. The average net utility plant included in the test year rate base is $793.954 million, provided in Schedule 3A, Page 1. As shown on this schedule, the average net utility plant is comprised of an average plant balance of $1,471.794 million minus an average depreciation reserve of $677.840 million.

B. Construction Work in Progress (CWIP)

Q. HAS CWIP BEEN INCLUDED IN THE TEST-YEAR RATE BASE?

A. Yes. However, the only CWIP that is included in rate base are costs related to projects of a short-duration (any capital project that is deemed routine and finishes work within a month) that do not accrue Allowance for Funds Used During Construction (AFUDC). I note the identification of short term CWIP ensures that no CWIP is recovered in base rates. Thus, there is no AFUDC offset added to operating income. The rate base amount reflects a simple average of projected short-term CWIP beginning and ending test year balances. This is consistent with the method employed in our last North Dakota electric rate case and matches the use of an average rate base.

Q. HOW WERE THE TEST YEAR BEGINNING AND ENDING CWIP BALANCES DETERMINED?

A. The beginning test year balance for CWIP was the June 30, 2020 actual balance. Construction expenditures, and transfers to Plant in Service during the remaining months of 2020 were netted against the June 30, 2020 balance to derive a beginning test year balance. The beginning test year CWIP balance was adjusted to reflect projected construction expenditures, and transfers to Plant In Service during the 2021 test year to obtain the ending test year CWIP balance. These projections were developed from the Company's 2021 capital budget.

Q. WHAT WAS THE LEVEL OF SHORT-TERM CWIP INCLUDED IN THE TEST YEAR RATE BASE?

A. As shown in Schedule 3A, Page 1, the average short-term CWIP included in rate base was $1.914 million.

C. Accumulated Deferred Income Taxes (ADIT)

Q. PLEASE DESCRIBE ACCUMULATED DEFERRED INCOME TAXES.

A. Inter-period differences exist between the book and taxable income treatment of certain accounting transactions. These differences typically originate in one period and reverse in one or more subsequent periods. For utilities, the largest such timing difference typically is the extent to which accelerated income tax depreciation exceeds book depreciation during the early years of an asset's service life. ADIT represents the cumulative net deferred tax amounts that have been allowed and recovered in rates in previous periods.

Q. WHY IS ADIT DEDUCTED IN ARRIVING AT TOTAL RATE BASE?

A. To the extent income taxes recovered in rates are deferred for later payment, they represent a prepayment by customers, a non-investor source of funds. The average projected ADIT balance is deducted in arriving at total rate base to recognize such funds are available for corporate use between the time they are collected in rates and ultimately remitted to the respective taxing authorities.

Q. WHAT AMOUNT OF ADIT WAS DEDUCTED IN THE PROJECTED TEST YEAR RATE BASE?

A. As shown on Schedule 3A, Page 1, $147.245 million was deducted. This amount reflects a simple average of the projected beginning and ending 2021 test year ADIT balances and incorporates Internal Revenue Service (IRS) tax regulations. Specifically, Sec. 1.167(l) of the tax code defines a pro-rated schedule for the extent average accumulated deferred income taxes can be used to reduce rate base to comply with the tax normalization requirements of the Code when forecast information is used to set rates.

Q. HOW DID THE FEDERAL TAX CUT AND JOBS ACT (TCJA) AFFECT THE PROPOSED ADIT IN RATE BASE?

A. The Commission's adoption of the Settlement in Case No. PU-18-155 requires the Company to amortize its excess plant-related ADIT using the Average Rate

Assumption Method, or ARAM, and amortize excess non-plant-related ADIT over periods ranging from five and fifteen years. Consistent with this requirement, the Company is amortizing the excess plant related ADIT using ARAM. Support for the excess non-plant ADIT can be found in Volume 3, Section III Rate Base (Plant), Tab P2-3.

D. Pre-Funded AFUDC

Q. WHAT IS PRE-FUNDED AFUDC?

A. During construction, AFUDC is calculated and is added to the cost of related capital projects and is reflected in rate base when the related capital project is placed into service. Once a project is placed in-service, the recording of AFUDC ceases, and the total capital cost of the project including accumulated AFUDC is recovered through depreciation.

However, the TCR includes a current return on CWIP as part of the revenue requirement calculation for the rider. The capital projects associated with the rider, therefore, do not include the accumulated AFUDC as part of rate base. Pre-funded AFUDC is needed to offset the accumulated AFUDC to align with the current return on CWIP in the rider.

Q. WHY IS AN ADJUSTMENT FOR PRE-FUNDED AFUDC NEEDED?

A. Pre-funded AFUDC is calculated and credited against the total jurisdictional AFUDC to prevent double-counting. This treatment, in effect, reduces the accumulated AFUDC that is added to rate base when a project is placed in-service. The Company tracks Pre-funded AFUDC and the non-rider AFUDC separately so that North Dakota jurisdictional customers are assured of receiving the entire benefit in lower fixed asset costs during the in-service period for the assets included in the TCR. In this way, we ensure that costs are recovered in the appropriate jurisdictions, pursuant to their specific ratemaking procedures.

E. Other Rate Base

Q. PLEASE SUMMARIZE THE ITEMS YOU HAVE INCLUDED IN OTHER RATE BASE.

A. Other Rate Base is comprised primarily of what is referred to as Working Capital. It also includes certain unamortized balances that are the result of specific ratemaking amortizations as discussed later in my testimony.

Q. PLEASE EXPLAIN WHAT WORKING CAPITAL REPRESENTS.

A. Working Capital is the average investment in excess of net utility plant provided by investors that is required to provide day-to-day utility service. It includes items such as materials and supplies, fuel inventory, prepayments, and various non-plant assets and liabilities. The net cash requirements, also referred to as Cash Working Capital, is a separate line item on various schedules.

Q. HOW HAVE TEST YEAR MATERIALS AND SUPPLIES AND FUEL INVENTORY REQUIREMENTS BEEN CALCULATED?

A. The Materials and Supplies and Fuel Inventory amounts shown on Schedule 3A, Page 1, are based on the thirteen-month average balances projected during the test year. Materials and Supplies average balance included in the test year rate base equals $10.807 million. The test year average rate base amount for Fuel Inventory is $6.579 million.

Q. How have the test year Non-Plant Assets & Liabilities been determined?

A. These balances as shown on Schedule 3A, Page 1, represent the 2021 calendar year estimate of these balances. Any book/tax timing differences associated with these items have been reflected in the determination of current and deferred income tax provision and ADIT balances previously discussed. This group is primarily comprised of assets that increase test year rate base by $8.415 million.

Q. How have the test year Prepayments and Other Working Capital items been determined?

A. Items of Prepayments and Other Working Capital, such as customer advances and deposits, are based on the actual thirteen-month average balances during the period ended June 30, 2020, as a proxy for the test year. The unamortized balances included in this section are based on the amortization schedules as described later in my testimony on revenue requirements. The net impact of these various items increase test year rate base by $5.026 million as shown on Schedule 3A, Page 1.

Q. How have test year Regulatory Amortizations been calculated?

A. The rate base amount reflects a simple average of beginning and ending test year balances.

Q. How have the test year Cash Working Capital requirements been determined?

A. Cash Working Capital requirements have been determined by applying the results of a comprehensive lead/lag study to the projected test year revenues and expenses.

Q. HAVE THE COMPONENTS OF THE TEST YEAR CASH WORKING CAPITAL BEEN CALCULATED CONSISTENT WITH METHODS USED IN THE MOST RECENT NORTH DAKOTA ELECTRIC RATE CASE?

A. Yes.

Q. PLEASE BRIEFLY EXPLAIN HOW A LEAD/LAG STUDY MEASURES CASH WORKING CAPITAL.

A. A lead/lag study is a detailed analysis of the time periods involved in the utility's receipt and disbursement of funds. The study measures the difference in days between the date services to a customer are rendered and the revenues for that service are received, and the date the costs of rendering the services are incurred until the related disbursements are actually made.

Q. HAS THE COMPANY'S LEAD/LAG STUDY BEEN UPDATED SINCE ITS LAST NORTH DAKOTA ELECTRIC RATE CASE?

A. Yes. The Company has updated the study for the calculation of expense lead days and revenue lag days for the twelve months ending December 31, 2019. The methodology for calculating the lead/lag days is consistent with the methodology used in the Company's prior electric and gas regulatory filings. The results of the updated lead/lag study for electric operations were incorporated into the North Dakota jurisdiction cash working capital rate base component as shown on Schedule 3A, Page 1.

Q. WHAT IS THE TEST YEAR CASH WORKING CAPITAL AMOUNT?

A. The amount included in the average rate base is a negative $7.103 million. The detailed components and calculations associated with this amount are summarized in Schedule 8.

Q. WHAT IS INDICATED BY THE NEGATIVE CASH WORKING CAPITAL AMOUNT?

A. Negative cash working capital indicates overall revenue collections occur sooner than the date when the associated costs of service are paid. In the Company's circumstance, taxing authorities (property taxes) comprise the largest source of cash working capital as offsets to working capital provided by the Company's investors. Other sources of offsets may include customers, creditors, and employees. The negative cash working capital reduces rate base to compensate customers for funds provided to meet cash working capital requirements.

Q. IS THE 2021 TEST YEAR RATE BASE FOR THE COMPANY'S NORTH DAKOTA JURISDICTION ELECTRIC OPERATIONS REASONABLE FOR PURPOSES OF DETERMINING FINAL RATES IN THIS PROCEEDING?

A. Yes. The test year rate base was developed on sound ratemaking principles in a manner similar to prior Company North Dakota electric rate cases.

V. INCOME STATEMENT

A. Revenues

Q. WAS THE IMPACT OF WEATHER ON PROJECTED SALES FOR THE TEST YEAR RECOGNIZED IN THE TEST YEAR REVENUE REQUIREMENT?

A. Yes. Test year retail sales levels assume normal weather.

Q. DO RETAIL OPERATING REVENUES REFLECT THE PROJECTED LEVEL OF UNBILLED SALES VOLUMES IN THE TEST YEAR FORECAST?

A. Yes. As Ms. Marks explains, the projected level of unbilled sales is incorporated into the retail sales forecast on a calendar-month basis. This eliminates the need to reconcile billing-month sales to calendar-month sales by recording unbilled revenues.

Q. HAVE YOU CONSIDERED OTHER OPERATING REVENUES AS AN OFFSET TO THE RETAIL REVENUE REQUIREMENT?

A. Yes. The test year includes items such as revenues from sales to other utilities (*i.e.,* wholesale margins), transmission-related revenue, and specific tariff charges including service activation fees, reconnection fees, and others. In areas where the Company did not budget for the collection of these other operating revenues, a representative level was determined and included in revenues in the cost of service study. One other source of revenues comes from billings to NSPW under the Interchange Agreement, which I discuss in more detail below.

Q. WHAT ARE WHOLESALE MARGINS?

A. There are two categories of wholesale margins (revenues less costs): asset based transactions and non-asset based transactions. Asset based sales are short-term sales of excess energy from Company owned generation assets or power purchase agreements (PPAs) executed to serve native load customers. Non-asset based transactions are wholesale (trading) transactions undertaken to obtain margins from purchases and sales of energy unrelated to meeting the energy needs of our native load customers. The only transactions that qualify as non-asset based are third-party supplied electricity or financial transactions that are not required to meet the needs of our retail customers and that are resold.

Q HOW IS THE COMPANY TREATING ASSET AND NON-ASSET BASED MARGINS?

A. Asset based margins are earned by selling energy from facilities or PPAs paid for by ratepayers. In Case No. PU-12-813, 100 percent of asset based margins were credited to customers through the FCR and the Company is continuing to do so in this rate case. In Case No. PU-07-776, non-asset based margins were shared equally between ratepayers and the Company, this treatment was carried forward in case No. PU-12-813 and we propose to do so in this rate case as well.

B. Operating and Maintenance Expenses

Q. HOW DOES THE COMPANY DEVELOP ITS TEST-YEAR PRODUCTION EXPENSE BUDGET?

A. The main area of expense in the production expense budget is fuel and purchased power. These expenses are developed through a production budget prepared to serve the combined energy and demand requirements of the NSP System (*i.e.*, for both NSPM and NSPW). Our Risk Management Department conducts a production simulation (called PLEXOS) model run based on the forecasted system sales to derive the forecasted fuel and energy costs. The NSP System fuel and energy costs are then adjusted to remove the cost of inter-system sales (also referred to as asset based sales) and other non-recoverable fuel items, so that a base cost of fuel and purchased energy is derived that only recovers the appropriate North Dakota jurisdictional share of these NSP System costs. The Commercial Operations group also forecasts our capacity purchases for contracts that will be in place during the test year and for short-term seasonal capacity purchases for the summer season. No short-term capacity purchases are included in the test year. Additionally, our Transmission Accounting department forecasts our transmission expenses to be paid to others for transmission service to support our generating fleet.

C. Depreciation Expense

Q. PLEASE IDENTIFY THE CASES ASSOCIATED WITH THE DEPRECIATION RATES USED IN THIS PROCEEDING.

A. Depreciation Expense for the test year was developed by using the depreciation rates as ordered in Case No. PU-07-776 and as carried forward in Case No. PU-12-813 which are then adjusted as described by Mr. Moeller. In light of the passage of time since depreciation rates were last set, the Company is proposing material changes. Where the Company proposes a depreciation rate change, that change is reflected as an adjustment on the rate base bridge schedule, Exhibit ___(BCH-1), Schedule 5 and income statement bridge schedule, Exhibit___(BCH-1), Schedule 6 for review in this case.

D. Taxes

Q. WHAT TAX EXPENSES ARE INCLUDED IN THE 2021 TEST YEAR INCOME STATEMENT?

A. We have line items for Property Tax; Income Taxes including Deferred Income Tax; Investment Tax Credits and Federal and State Income Tax; and Payroll Tax. The State and Federal income taxes are calculated in in Exhibit___(BCH-1), Schedule 3A, 2021 Test Year Cost of Service Study, Page 3.

Q. How are income taxes determined for the jurisdiction?

A. Income taxes are determined based on total before tax book income, tax additions, and deductions which determine deferred income taxes and the resulting taxable income that is used to calculate federal and state income taxes. The federal income tax rate reflects the 21 percent rate effective January 1, 2018 with the enactment of the TCJA. The utilization or generation of net operating losses or tax credits impact both deferred income taxes and federal and state income taxes, which I will discuss in more detail below.

Q. Please summarize the ratemaking treatment of Net Operating Losses (NOLs).

A. A NOL is created when taxable deductions exceed taxable revenue; when this occurs, the excess deductions are carried forward to future periods. NOLs require an adjustment that offsets the part of the ADIT rate base reduction that is associated with the accelerated depreciation deductions. That adjustment is needed to keep the Company's rate base consistent with the income tax deductions that the Company has been able to use. Keeping a balance of rate base reductions resulting from the ADIT and the use of accelerated depreciation is required under federal income tax law as part of "normalization" for both accounting and ratemaking.

The Company continues to give back to retail customers annually the revenue requirement benefit associated with the utilization of tax deductions and credits carried forward from prior periods. The timing of utilization and the carry-forward balances associated with unused deductions and credits will continue to change over time as the Company's revenue and deduction levels change.

Q. PLEASE EXPLAIN HOW THE COMPANY DETERMINES WHETHER DEFERRED TAX ASSETS (DTAS) ARE CREATED OR CONSUMED.

A. The calculation of income taxes determines whether DTAs are created or consumed. After the calculated income tax expense is reduced for allowed NOL deductions or tax credits, the remaining income tax credits and deductions are "carried forward" and can be used to reduce taxes in future years. The federal income tax code and tax regulations dealing with NOLs state that unused deductions carried forward to a future tax year must be utilized before credits. The opposite is true when DTAs are created. To the extent the calculated income tax expense is negative, first tax credits, and then depreciation deductions, are reversed, carried forward, and are available for utilization in a future period. This reversal creates a reduction to deferred tax expense, resulting in the creation of a DTA.

In future periods, to the extent the calculated income tax expense is positive, the federal income tax code and tax regulations prioritize depreciation deductions that were carried forward, and then credits that were carried forward are utilized to reduce the income tax expense by 80 percent for depreciation deductions and 75 percent for credits. This utilization creates an increase in deferred tax expense, reducing the balance of the DTA. Once all depreciation deductions and credits previously carried forward are utilized, the Company will have returned to a positive tax position. This is normal NOL accounting.

For the purpose of determining the NOL, these income tax calculations are done on an all-inclusive jurisdictional cost of service basis in which rider revenues and rider related investments are included with non-rider revenues and investments. This approach determines the extent to which the Company's

Electric Utility North Dakota retail jurisdiction is in a tax loss position or in a position to utilize deductions and credits carried forward from previous periods, as is the case with the 2021 test year. This approach ensures that any reduction in revenue requirements resulting from the utilization of deductions or credits carried forward from prior periods is returned to customers as soon as it is available in the form of a reduction to base rates.

These balances related to unused credits and deductions are reported in the Company's May 1 Jurisdictional Annual Reports, including the most recent May 1, 2020 Jurisdictional Annual Report. By having these annual determinations made on an all-in basis, the jurisdictional cost of service study (JCOSS) includes actual data for both rider recovery and base rate recovery. Any change in rider recovery by the Commission will be incorporated in this process.

Q. DO THE DTAS AFFECT THE 2021 TEST YEAR REVENUE REQUIREMENTS?

A. Yes. The Company's 2021 test year COSS includes a revenue requirement increase associated with PTCs carried forward from prior periods to the 2021 test year and generation of federal and state tax credits to be carried forward based on the Company's 2021 test year COSS. An accounting for the balances carried forward to the 2021 test year COSS, as well as the documented calculations supporting this revenue requirement increase, can be found in Exhibit___(BCH-1), Schedule 16, Net Operating Loss.

It should be noted that any change in the revenues, expenses, or capital structure will cause the income tax calculation to be changed. This could in turn affect the timing of the DTAs being generated or consumed and added to or removed from rate base. The Company will update the 2021 test year COSS accordingly.

Q. HOW WILL THE RATES SET IN THIS CASE AFFECT THE UTILIZATION OF DTAS IN FUTURE TEST YEARS?

A. The utilization of DTAs is based on taxable income for the Company's North Dakota Electric Retail jurisdiction. Taxable income is determined by total revenues less total deductions and total tax credits. Once base rates are set in this case for the 2021 test year, they will remain in place until changed in another electric rate case. If all other factors are held constant, an increase in base rate revenue as proposed by the Company in this case will increase the utilization of deferred tax assets in future years.

Q. WHAT ARE PRODUCTION TAX CREDITS?

A. Federal law provides tax credits for owners of qualifying renewable resources based on the energy production of the given resource. These PTCs are granted to owners of renewable resources based on the total kWh of energy generated by the resource during its first ten years of commercial operation, and the value of the PTCs per kWh varies depending on the timing of the resource's construction.

Q. DOES THE COMPANY PROPOSE TO CHANGE ITS TREATMENT OF PRODUCTION TAX CREDITS IN THIS RATE CASE?

A. Yes. At the request of the Commission and Commission Staff, the Company proposes to "normalize" the benefits of future PTCs by spreading the value of the PTCs over the life of the resource that produces them, usually between twenty and twenty-five years. We refer to our proposed approach as the "Levelized Credit Method," or LCM. The Company requests that, if the Commission desires to "normalize" PTCs going forward, that the Commission adopt for ratemaking purposes the Company's proposed LCM approach to be used in base rates to evenly and fairly distribute the credits over the full life of the resource.

Q. WHY ARE PTCS VALUABLE TO THE COMPANY'S CUSTOMERS?

A. PTCs are valuable to customers because they can be used to reduce the Company's tax liability and, consequently, the amount the Company needs to recover from customers in rates to satisfy that liability.

Q. HOW HAVE PTCS HISTORICALLY BEEN TREATED BY THE COMPANY?

A. In the past, the Company has passed on the benefits of PTCs to customers as they are generated—meaning the value of all PTCs for a given project are passed on to customers during the first ten years of a project's operation, in accordance with the federal statutory structure.

Q. HOW DID THIS NEW PROPOSED PTC TREATMENT COME ABOUT?

A. In the informal hearing considering the Company's 2019 Renewable Energy Rider (RER) in Case No. PU-18-368, the Commission questioned whether passing on the benefits of PTCs as they are generated during the first ten years of a resource's life created issues of intergenerational equity that negatively affected customers paying for a resource after its first ten years without receiving any PTC benefits. With Commission direction to address this issue, the Company subsequently began working with Commission Staff to develop proposals to address this issue of generational equity and "normalize" the benefit of the PTCs in the future by spreading the benefit across the life of a given resource.

Q. HOW DOES THE COMPANY PROPOSE TO CHANGE ITS ACCOUNTING TREATMENT OF PTCS?

A. As I mentioned, the Company proposes to use an approach we call the Levelized Cost Method (LCM), under which the Company forecasts the total PTCs that would be generated during a resource's first ten years of operation, divides this amount by the resource's expected life, and assigns the quotient as a credit to each year of the resource's life. The forecasted PTCs would then be trued up against actuals annually in the RER filing. This means excess PTCs generated above the forecasted level or shortage in PTCs below the forecasted level will be passed through to customers evenly over the remaining life of the project through the RER, to maintain generational equity.

Q. CAN THE LCM BE USED FOR A RESOURCE THAT IS ALREADY IN SERVICE?

A. Yes. Where adoption of the LCM occurs after a resource has already been in service, the calculation of the annual levelized PTC for the remaining years of service would be based on the remaining total PTCs forecasted to be generated for the resource dividing by the remaining life of the resource.

Q. HOW DOES THE COMPANY ACCURATELY FORECAST THE NUMBER OF PTCS THAT A RESOURCE WILL GENERATE?

A. The Company forecasts the number of PTCs that a resource will generate using its expected run time based on historical data. As stated above, the forecasted PTCs would then be trued up against actuals annually in the RER filing.

Q. WHAT ARE THE ADVANTAGES OF THE LCM APPROACH?

A. The LCM is notably simpler to calculate, administer, and explain than other methods of normalizing PTCs that the Commission and Commission Staff have considered. Additionally, the LCM directly addresses the generational inequity of PTCs as identified by the Commission by evenly spreading the PTCs to customers throughout the anticipated life of a resource.

Q. FROM A REGULATORY ACCOUNTS PERSPECTIVE, HOW WILL THE COMPANY PUT THE LCM INTO PRACTICE?

A. The Company proposes to implement the LCM in base rates. This means the revenue impacts associated with spreading the benefits of PTCs throughout the life of the resource will be in base rates, and the cost associated with spreading PTCs over the life of the project will be placed into a regulatory liability until the PTC is applied. The amount of federal tax credits, including PTCs and the LCM adjustment included in the COSS are summarized on Exhibit___(BCH-1), Schedule 17.

Q. HAS THE COMPANY PROPOSED THE LCM TO THE COMMISSION BEFORE?

A. Yes, in our 2020 RER proceeding (Case No. PU-19-329), the Company proposed the LCM approach to "normalizing" the benefits of PTCs over the life of a renewable resource.

Q. DID THE COMMISSION APPROVE USE OF THE LCM IN THAT PROCEEDING?

A. Yes. The Company and the Commission discussed the LCM in an informal hearing in Case No. PU-19-329, and the Commission subsequently approved the Company's RER rate on February 19, 2020. The Company now requests the Commission to approve use of the LCM approach in base rates for all resources that are included in base rates. All resources included in the rider will use LCM in the rider to keep the costs and the associated PTC LCM in the same recovery mechanism.

E. AFUDC

Q. WHAT IS AFUDC?

A. As previously noted, AFUDC is the cost of financing during the period a capital investment is constructed. Once an asset is placed in service, the total cost to construct, including accumulated AFUDC, is recovered through depreciation expense.

F. Interchange Agreement

Q. PLEASE DESCRIBE THE INTERCHANGE AGREEMENT WITH NSPW THAT YOU REFERENCED EARLIER.

A. The Company and NSPW operate a single integrated electric generation and transmission system and a single electrical "local balancing authority area." The integrated system jointly serves the electric customers and loads of the Company and NSPW. However, the specific generators and transmission facilities making up the integrated system are owned by the two separate legal entities (the Company and NSPW), with the ownership boundary at the Minnesota/Wisconsin border. The Interchange Agreement is a FERC approved contractual mechanism that provides a means to share the costs of the integrated system between the Company and NSPW.

Q. PLEASE DESCRIBE THE COSTS ALLOCATED BETWEEN THE COMPANY AND NSPW UNDER THE INTERCHANGE AGREEMENT.

A. Under the Interchange Agreement, the Company and NSPW share annual system generation (production) and transmission costs. Under the Interchange Agreement formulas, approximately 16 percent of the costs of the Company system are allocated to NSPW, and approximately 84 percent of the NSPW system costs are allocated to the Company. These allocations are appropriate because approximately 84 percent of the load on the integrated system is the Company load and 16 percent is NSPW load. The exact allocation percentages are determined by allocation factors updated and filed at FERC annually. The Interchange Agreement also provides for an allocation of revenues received by the Company and NSPW, such as revenues from off-system wholesale sales. Interchange Agreement costs and revenues are budgeted by the Company and NSPW annually. Thus, the Company's budget shows Interchange Revenues – revenues that reflect the charges to NSPW for its share of production and transmission assets and associated expenses. Likewise, Interchange Expense reflects the Company's forecasted payments to NSPW for its proportionate share of the costs of generation and transmission assets and associated expenses incurred by NSPW to serve the NSP System needs.

The 2021 test year Interchange Revenue and Interchange Expenses have been calculated using 2021 Company and NSPW budget information. This is consistent with the treatment of Interchange Revenues and Interchange Expenses in our last electric rate case.

VI. UTILITY AND JURISDICTIONAL ALLOCATIONS

Q. PLEASE DESCRIBE THE METHODS USED TO ALLOCATE COSTS TO THE COMPANY'S ELECTRIC UTILITY OPERATIONS.

A. The test year includes both costs incurred directly by the Company's electric operating business and costs directly assigned or allocated by the Service Company for corporate functions (*e.g.,* accounting, human resources, law, etc.). The Service Company cost allocation and billing process is subject to FERC jurisdiction and authorization under a Utility Services Agreement between the Service Company and the Company.

Cost allocation and assignment principles have not changed since our last North Dakota electric rate case. O&M cost assignments and allocations are also consistent with the Company's recent Minnesota electric rate case filed on November 2, 2020 with the Minnesota Public Utilities Commission (MPUC Docket No. E002/GR-20-723). Non-O&M costs include such items as book depreciation expense, deferred income taxes, and property taxes. All of the investments common to the electric and natural gas utilities, and their related costs (*e.g.*, software or other common investments and expenses), are evaluated as to whether the cost should be direct assigned to electric or natural gas, or allocated based on appropriate allocators such as: Customers, Customer Bills, Transportation Studies, or the three factor general allocator (the average of Revenue Ratio, Employee Ratio, and Asset Ratio).

Additional information regarding this process and the reason for selecting a particular allocator is also included in the Cost Assignment and Allocation Manual (CAAM) which I have included as Exhibit___(BCH-1), Schedule 12. There have not been any changes since the last electric rate case that would significantly impact the percentage of costs that are assigned to North Dakota.

Q. PLEASE DESCRIBE THE METHODS USED TO ALLOCATE COSTS FOR THE COMPANY'S ELECTRIC UTILITY OPERATIONS IN NORTH DAKOTA.

A. O&M cost assignments and allocations are summarized on Exhibit___(BCH-1), Schedule 13. The expense budgets relied upon to develop test-year income statement items were generally prepared on a functional basis (*i.e.,* Production, Transmission, Distribution, Customer Accounts, Customer Information, Sales, Administrative and General). These functional amounts are directly assigned to North Dakota jurisdiction electric operations or allocated to the electric operations based on cost causation.

Q. PLEASE EXPLAIN THE PROCESS FOR ASSIGNING THE COMPANY'S INVESTMENT IN ELECTRIC PLANT TO THE NORTH DAKOTA JURISDICTION.

A. A summary and description of the allocation factors used to allocate capital related items to the North Dakota jurisdictional electric operations income statement and rate base is contained in Exhibit___(BCH-1), Schedule 14. Plant investments are accounted for in the manner prescribed by the FERC Uniform System of Accounts. Detailed records are maintained on a functional basis (*e.g.*, Production, Transmission, Distribution). The capital budgets, from which the projected plant balances in rate base were developed, are also prepared on a functional basis. These functional amounts are assigned to the appropriate jurisdiction directly or allocated based on the use of such assets in providing electric service in a particular jurisdiction and the underlying elements of cost causation.

Q. PLEASE EXPLAIN THE NEED FOR JURISDICTIONALLY ALLOCATING THE INVESTMENTS IN PRODUCTION AND TRANSMISSION FACILITIES.

A. The NSPM and NSPW production and transmission system (NSP System) is designed, built, and operated to provide an integrated source of electricity for all of our and NSPW's electric customers in five states. Costs are allocated first between NSPM and NSPW through the Interchange Agreement as approved by FERC, which I discussed earlier in my testimony. NSPM's portion of costs is then allocated to utility operations in North Dakota, Minnesota, and South Dakota.

To determine the level of investment associated with the provision of electric service to North Dakota retail customers, it is necessary to assign or allocate a portion of the total production and transmission investment to each jurisdiction. We used each jurisdiction's respective coincident peak demands for electricity as the basis for this allocation. It is reasonable to use coincident peak demands as an allocation basis because these facilities are constructed to meet both overall base load, intermediate, and peak requirements and operate as an integrated system across all jurisdictions. This is consistent with the methodology accepted in the last North Dakota electric rate case and the study produced from that last case. The exception to this are the Company-owned wind projects which are allocated to jurisdiction on the basis of energy. We believe this is a more reasonable allocation basis since wind farms are generally constructed to meet energy needs, not to meet demand requirements.

Q. HOW WERE THE DISTRIBUTION INVESTMENT AMOUNTS ASSIGNED TO THE NORTH DAKOTA JURISDICTION?

A. The Company's electric distribution plant investment amounts have been directly assigned, when possible, based upon the jurisdiction(s) served by each of the individual distribution facilities. Therefore, North Dakota distribution investments are generally assigned directly to North Dakota. However, if

Distribution Investments include components that are common or general plant in nature they are allocated based on their functional class, consistent with the CAAM.

VII. ANNUAL ADJUSTMENTS TO THE TEST YEAR

Q. WHAT TOPICS DO YOU ADDRESS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I explain adjustments that affect our proposed 2021 test year forecast revenue requirement. These adjustments were identified during our review of the 2021 budget and preparation for this case. An individual adjustment may be related to a previous Commission Order, reflect Commission policy or traditional ratemaking treatment, or may be proposed to address a situation particular to this rate case. In this section, I provide details related to each adjustment and explain why each is necessary in order to present a representative level of rate base or costs in the test year forecast.

Q. PLEASE DESCRIBE THE TYPES OF ADJUSTMENTS MADE TO THE 2021 TEST YEAR.

A. I present traditional adjustments consistent with treatment in prior cases and existing Commission Policy Statements (Precedential Adjustments) and rate case adjustments related to this particular case (Rate Case Adjustments). Next, I explain the various amortizations affecting the test year (Amortizations), the removal of certain costs and revenues being recovered through riders (Rider Removals), and a group of adjustments that are the result of secondary dynamic calculations in the cost of service model (Secondary COS Calculations) and certain adjustments that may be necessary for Rebuttal Testimony in this proceeding.

Q. PLEASE LIST THE 2021 TEST YEAR ADJUSTMENTS.

A. The following adjustments were made to rate base and the income statement where applicable. Rate base adjustments are shown on Exhibit___(BCH-1), Schedule 5, 2021 Test Year Bridge Schedule - Rate Base, and income statement (revenue requirement) adjustments are shown on Exhibit___(BCH-1), Schedule 6, 2021 Test Year Bridge Schedule - Income Statement. Column 1 of the Rate Base bridge schedule shows the 2021 unadjusted rate base by each component of rate base. Each adjustment to rate base is contained within a column that shows its effect on each rate base component. Likewise, Column 1 of the Income Statement bridge schedule shows the 2021 unadjusted income statement by each component of the income statement. As with rate base, each adjustment to the income statement is contained within a column that shows its effect on each income statement component. In addition, the Income Statement bridge schedule shows the impact of each rate base and income statement adjustment on the revenue requirement. Exhibit___(BCH-1), Schedule 4 List of Adjustments provides adjustment amounts for the 2021 test year.

<u>Rate Case Adjustments</u>

1) Decommissioning
2) Depreciation Study - Production
3) Depreciation Study – Transmission, Distribution, and Gas
4) Economic Development Donations
5) Foundation and Other Donations
6) Incentive Compensation
7) PI EPU Recovery
8) Dues: Chamber of Commerce

9) RER PTC Amortization

10) Non-Plant Tax Reform Excess ADIT

Amortizations

11) RTF

12) Income Tax Tracker Amortization

13) NOL Tax Reform Regulatory Amortization

14) Rate Case Expense

Rider Removals

15) RER Rider

16) TCR Rider

Secondary Cost of Service Calculations

17) ADIT Pro-Rate – IRS Required

18) Cash Working Capital

19) Net Operating Loss

20) Change in Cost of Capital

Each of these adjustments is discussed in more detail in this section of my testimony.

Q. IS THE 2021 O&M EXPENSE FORECAST FOR THE COMPANY'S ELECTRIC UTILITY OPERATIONS AN ACCURATE AND RELIABLE PROJECTION?

A. Yes. With the adjustments I previously described, it is an accurate and reliable projection on which to base this rate request.

A. Precedential Adjustments

Q. PLEASE LIST THE PRECEDENTIAL TEST YEAR ADJUSTMENTS INCLUDED IN THE REVENUE REQUIREMENT CALCULATION.

A. Exhibit___(BCH-1), Schedule 4 List of Adjustments provides a list of Precedential Adjustments and their associated revenue requirement impact, based on past rate case precedent for the 2021 test year.

Q. HOW DOES THE COMPANY PROVIDE SUPPORT FOR THESE PRECEDENTIAL ADJUSTMENTS?

A. Treatment of these precedential adjustments has not changed from the Commission's Order in the Company's previous completed electric rate cases. As such, the Company has provided the adjustments themselves in Schedules to my Direct Testimony, and support for these adjustments, including a detailed description of each adjustment and supporting materials, in the workpapers identified in Exhibit___(BCH-1), Schedule 4 List of Adjustments. This organization is intended to facilitate the review of and full support for each adjustment within the identified workpaper.

B. Rate Case Adjustments

1) Decommissioning

Q. PLEASE DESCRIBE THE DECOMMISSIONING ADJUSTMENT TO RATE BASE.

A. This adjustment updates the 2021 test year to include the impact of increasing the nuclear decommissioning accrual. This adjustment is further supported by Mr. Moeller in his Direct Testimony in Exhibit___(MPM-1).

This adjustment impacts the 2021 test year revenue requirements by the amounts shown on:

- Schedule 5, page 1, row 43, column 7,
- Schedule 6, page 1, row 39, column 7,
- Schedule 4, page 1, row 14, column 5
- Volume 3, Section VIII Adjustments, Tab A10.

2) Depreciation Study Production

Q. PLEASE DESCRIBE THE PRODUCTION DEPRECIATION STUDY ADJUSTMENT TO RATE BASE.

A. This adjustment updates the 2021 test year to include the impact of the Company's 2020 Depreciation Study related to production. This adjustment is further supported by Mr. Moeller in his Direct Testimony in Exhibit___(MPM-1).

This adjustment impacts the 2021 test year revenue requirements by the amounts shown on:

- Schedule 5, page 1, row 43, column 8,
- Schedule 6, page 1, row 39, column 8,
- Schedule 4, page 1, row 15, column 5
- Volume 3, Section VIII Adjustments, Tab A11.

3) Depreciation Study - Transmission, Distribution, and General

Q. PLEASE DESCRIBE THE DEPRECIATION STUDY ADJUSTMENT TO RATE BASE.

A. This adjustment updates the 2021 test year to include the impact of the Company's 2017 Depreciation Study related to TD&G. This adjustment is further supported by Mr. Moeller in his Direct Testimony in Exhibit___(MPM-1).

This adjustment impacts the 2021 test year revenue requirements by the amounts shown on:

- Schedule 5, page 1, row 43, column 8,
- Schedule 6, page 1, row 39, column 8,
- Schedule 4, page 1, row 16, column 5
- Volume 3, Section VIII Adjustments, Tab A12.

4) Economic Development Donations

Q. PLEASE IDENTIFY THE COMPANY'S ECONOMIC DEVELOPMENT PROGRAMS CURRENTLY AVAILABLE.

A. The Company makes contributions to a number of regional and local economic development organizations positioned to combine resources for the purpose of maintaining and improving the long-term economic health of communities in our service territory or retaining employment opportunities and expanding the state and local tax base.

The Company can, through a donation, provide communities or organizations involved in community and economic development with either an operating grant or a one-time investment in a special project that supports the community and economic development efforts of our communities.

This adjustment impacts the 2021 test year revenue requirements by the amounts shown on:

- Schedule 5, page 1, row 43, column 10,
- Schedule 6, page 1, row 39, column 10,
- Schedule 4, page 1, row 17, column 5

- Volume 3, Section VIII Adjustments, Tab A13.

5) Foundation and Other Donations

Q. PLEASE DESCRIBE THE CHARITABLE CONTRIBUTION ADJUSTMENT.

A. The Company is proposing to include 50 percent of corporate charitable contributions benefiting the State of North Dakota in the test year. An analysis was performed on contribution details to ensure that only amounts contributed to charities and institutions that could be associated with the Company's electric service territory in the North Dakota jurisdiction were included in the cost of service.

This adjustment impacts the 2021 test year revenue requirements by the amounts shown on:

- Schedule 5, page 1, row 43, column 11,
- Schedule 6, page 1, row 39, column 11,
- Schedule 4, page 1, row 18, column 5
- Volume 3, Section VIII Adjustments, Tab A14.

6) Incentive Compensation

Q. WHAT ADJUSTMENTS HAVE YOU MADE TO THE INCENTIVE COMPENSATION EXPENSE INCLUDED IN THE UNADJUSTED TEST YEAR?

A. The test year adjustment reflects the exclusion of the budgeted costs for: 1) the long-term portion of incentive compensation, excluding time based and environmental incentive; 2) any non-corporate incentive plan costs; and 3) all Annual Incentive Plan costs above 20 percent of base pay. Company Witness Mr. Greg Chamberlain supports this adjustment in his Direct

Testimony.

Q. WHAT IS THE IMPACT OF THE INCENTIVE COMPENSATION ADJUSTMENT ON THE TEST YEAR?

A. This adjustment impacts the 2021 test year revenue requirements by the amounts shown on:

- Schedule 5, page 1, row 43, column 12,
- Schedule 6, page 1, row 39, column 12,
- Schedule 4, page 1, rows 19-22, column 5
- Volume 3, Section VIII Adjustments, Tab A15-18.

7) PI EPU Recovery

Q. PLEASE DESCRIBE THE PI EPU RECOVERY ADJUSTMENT TO RATE BASE.

A. This adjustment updates the 2021 test year to include the impact of the abandoned Prairie Island Extended Power Uprate (PI EPU) project costs over the remaining life of the plant through an amortization expense. Consistent with past precedent in North Dakota for recovery of abandon plant cost the Company created a deferral tracking the costs. Company Witness Mr. Christopher Shaw discuss the prudence of abandoning the PI EPU project in his Direct Testimony.

This adjustment impacts the 2021 test year revenue requirements by the amounts shown on:

- Schedule 5, page 1, row 43, column 14,
- Schedule 6, page 1, row 39, column 14,
- Schedule 4, page 1, row 23, column 5

- Volume 3, Section VIII Adjustments, Tab A19.

8) Dues: Chamber of Commerce

Q. DOES THE COMPANY'S REQUEST INCLUDE RECOVERY OF ASSOCIATION DUES PAID TO CHAMBERS OF COMMERCE?

A. Yes. The Company has included membership dues paid to various Chambers of Commerce in North Dakota in the 2021 test year. Chambers of Commerce provide an essential link between the Company and the communities it serves, allowing for improved utility service. Because membership in these organizations provides benefits to all utility customers, recovery of membership dues paid to Chambers of Commerce is appropriate. Chamber of Commerce dues are initially recorded below the line; thus, an adjustment is necessary to include Chamber of Commerce dues in test year costs.

This adjustment impacts the 2021 test year revenue requirements by the amounts shown on:

- Schedule 5, page 1, row 43, column 9,
- Schedule 6, page 1, row 39, column 9,
- Schedule 4, page 1, row 24, column 5
- Volume 3, Section VIII Adjustments, Tab A20.

9) RER PTC Amortization

Q. PLEASE DESCRIBE THE RER PTC AMORTIZATION ADJUSTMENT.

A. As noted previously in my testimony, the Company is proposing to use LCM to spread the PTC benefits to customers over the life of the applicable resource.

This adjustment updates the 2021 test year to decrease the amount of PTC credits returned to customers and create a regulatory liability.

This adjustment impacts the 2021 test year revenue requirements by the amounts shown on:

- Schedule 5, page 1, row 43, column 15,
- Schedule 6, page 1, row 39, column 15,
- Schedule 4, page 1, row 25, column 5
- Volume 3, Section VIII Adjustments, Tab A21.

10) Non-Plant Tax Reform Excess ADIT

Q. PLEASE DESCRIBE THE NON-PLANT ADIT ASSOCIATED WITH THE TAX CUTS AND JOBS ACT (TCJA) ADJUSTMENT TO RATE BASE.

A. This adjustment updates the 2021 test year to include the impact of the non-plant ADIT associated with TCJA. The adjustment is based on the excess non-plant ADIT created when adjusted for the change in federal tax rates from 35 percent to 21 percent. This adjustment is consistent with the Commission's Order in Case No. PU-18-155 to amortize its excess non-plant-related ADIT over periods ranging from five to fifteen years.

This adjustment impacts the 2021 test year revenue requirements by the amounts shown on:

- Schedule 5, page 1, row 43, column 13,
- Schedule 6, page 1, row 39, column 13,
- Schedule 4, page 1, row 26, column 5
- Volume 3, Section VIII Adjustments, Tab A22.

C. Amortizations

11) Resource Treatment Framework (RTF)

Q. ARE THERE ANY ADDITIONAL AMORTIZATIONS INCLUDED IN THE TEST YEAR?

A. Yes. The Company also proposes to recover $1.8 million in transaction costs associated with preparing the Resource Treatment Framework (RTF) that the Company proposed in Case Nos. PU-12-813, *et. al.*.

Q. WHAT IS THE RESOURCE TREATMENT FRAMEWORK?

A. In the First Revised Negotiated Agreement in Case No. PU-12-813 (Negotiated Agreement), approved by the Commission in a March 9, 2016 Order, the Company and Commission Staff (Parties) agreed that the Company would propose a long-term Resource Treatment Framework (RTF) to address the Company's long-term plans for addressing divergent state energy policies. The Company was required to file its long-term RTF proposal no later than January 1, 2017. The Negotiated Agreement addressed the short-term treatment of certain existing and pending resources, but did not resolve the long-term treatment of new resource additions. At the time, the Company was entering a 20-year period in which significant portions of our generating fleet would be retired and replaced. The Commission and Commission staff for several years had expressed concerns about the costs of environmental mandates in other NSP jurisdictions being borne by North Dakota customers. The goal of the RTF was to develop a framework for planning and assigning the costs of new resources as the Company transitioned its fleet.

Company Witness Mr. Chamberlain discusses the RTF in more detail in his Direct Testimony.

Q. COULD YOU ADDRESS THE RESOURCE TREATMENT FRAMEWORK, ITS COSTS AND THE COMPANY'S PROPOSAL FOR RECOVERING THESE COSTS?

A. Yes. In compliance with the Agreement I described earlier, on December 31, 2016, the Company filed its Application for Consideration of a Resource Treatment Framework to Address Jurisdictional Cost Allocation Issues as a Compliance Filing in Case No. PU-12-813. In the RTF proposal and supporting schedules, the Company provided a high-level estimate of the transaction costs associated with implementing either the Pseudo Separation or Corporate Separation proposed in our RTF filing to be approximately $1 million. At the time, it appeared that there would need to be some type of transaction to effectuate the ultimate outcome of the RTF through a corporate restructuring (either via rate mechanisms or through a corporate reorganization). Based on this estimate and in anticipation of a potential separation of NSP jurisdictions, the Company created a deferral account to capture our transaction costs for the eventual implementation of any final RTF outcome. Given the complexity of this potential transaction, significant assistance from consultants and other outside advisors was required.

Q. COULD YOU PROVIDE FURTHER INFORMATION ABOUT THE DEFERRAL ACCOUNT FOR THE RTF TRANSACTION COSTS?

A. The Company created the deferral account to track the costs associated with structuring the highly complex separation options presented in the RTF proceeding as well as the initial costs of implementing a potential separation. In light of the nature of the RTF, the Company believed that recovery of transaction costs would be appropriate – and included them in its RTF proposal. This deferral account was created similar to deferral accounts associated with other transactions—for example, acquiring a generating resource or a utility acquisition or merger. Like those other types of transactions, significant costs can be incurred in preparing the transaction, even if the Company does not ultimately implement the merger or resource acquisition. Creating a deferral account also ensures that the Company's transaction costs associated with the RTF are kept separate from other outside consulting services.

The deferral represents our actual costs, which we recognize were higher than our initial estimate. However, given the complexity and difficulty of the RTF proposal, these costs are consistent with our expectations.

Q. HOW DOES THE COMPANY PROPOSE TO RECOVER THE OUTSTANDING TRANSACTION COSTS OF THE RTF?

A. The Company proposes to amortize the costs of this deferral over 10 years.

This adjustment impacts the 2021 test year revenue requirements by the amounts shown on:

- Schedule 5, page 1, row 43, column 17,
- Schedule 6, page 1, row 39, column 17,
- Schedule 4, page 1, row 29, column 5
- Volume 3, Section VIII Adjustments, Tab A23.

12) Income Tax Tracker Amortization

Q. PLEASE DESCRIBE THE INCOME TAX TRACKER AMORTIZATION.

A. The Company has concluded tax audits with the IRS and the Minnesota Department of Revenue for tax years ended 2010 through 2016. As a result of the audits, the Company paid tax and interest on the disputed amounts. We propose to collect this amount over the three years consistent with rate case expenses.

This adjustment impacts the 2021 test year revenue requirements by the amounts shown on:

- Schedule 5, page 1, row 43, column 16,
- Schedule 6, page 1, row 39, column 16,
- Schedule 4, page 1, row 30, column 5
- Volume 3, Section VIII Adjustments, Tab A24.

13) NOL Tax Reform Regulatory Amortization

Q. PLEASE DESCRIBE THE NOL TAX REFORM REGULATORY AMORTIZATION.

A. The Commission's Order in Case No. PU-18-155 approved the Company's proposed amortization level included in the TCJA refund calculation. This is being amortized over 23 years.

This adjustment impacts the 2021 test year revenue requirements by the amounts shown on:

- Schedule 5, page 1, row 43, column 18,
- Schedule 6, page 1, row 39, column 18,
- Schedule 4, page 1, row 31, column 5
- Volume 3, Section VIII Adjustments, Tab A25.

14) 2021 Rate Case Expense Amortization

Q. PLEASE DESCRIBE THE 2021 RATE CASE EXPENSES AMORTIZATION.

A. The Company requests approval of $1.126 million of projected direct expenses associated with this rate case docket and a three-year amortization period. In addition, the Company is including costs associated with a study totaling $132 thousand to be amortized over the same three-year amortization period. In total this results in an annual amortization amount of $419 thousand. A three-year amortization period is consistent with our requested amortization period for other amortizations in the rate case.

This adjustment impacts the 2021 test year revenue requirements by the amounts shown on:

- Schedule 5, page 1, row 43, column 19,
- Schedule 6, page 1, row 39, column 19,
- Schedule 4, page 1, row 32, column 5
- Volume 3, Section VIII Adjustments, Tab A26.

Q. WHAT STUDY DID THE COMPANY INCLUDE IN THE RATE CASE EXPENSE AMORTIZATION ABOVE?

A. In its February 26, 2014 Order Adopting Settlement in Case No. PU-12-813, the Commission directed the Company to complete a Jurisdictional Allocation Study. The Commission's Order directed the Company to work with their Staff and an independent third party to study various jurisdictional demand allocation methodologies. The study was completed and provided as a Compliance Filing in Case No. PU-12-813 on April 27, 2015. The Settlement Agreement provided that the costs of the study should be recovered as a rate case expense in the Company's next electric rate case.

D. Rider Removals

Q. WHAT TOPICS DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section, I present our proposed treatment of costs currently recovered in riders during the test year period including costs which we propose to continue to collect through the riders and costs we propose moving to base rates.

Q. WHAT RIDER MECHANISMS ARE CURRENTLY USED BY THE COMPANY?

A. The Company currently uses three cost recovery riders:

- Renewable Energy Recovery (RER) Rider;
- Transmission Cost Recovery (TCR) Rider; and
- Fuel Cost Rider (FCR)

Q. WHAT IS THE COMPANY PROPOSING WITH RESPECT TO THE TREATMENT OF COSTS RECOVERED THOUGH RATE RIDERS?

A. The Company proposes:

- Continued use of the RER Rider for recovery of costs and Production Tax Credits (PTCs) related to the Freeborn and Dakota Range Wind Farms.
- Costs for Border, Courtenay, Foxtail, Blazing Star I and II, Lake Benton and Crowned Ridge Wind Farms will be moved to base rates upon implementation of final rates in this case.
- Continued use of the TCR Rider for recovery of costs associated with ongoing transmission projects and MISO Regional Expansion Criteria and Benefits (RECB) Schedule 26 and 26A net revenues. Costs for all

in-service projects[1] will be moved to base rates upon implementation of final rates in this case.

- Continue use of the FCR in its current form.

These proposals are consistent with the rider filings we made during 2020 in our separate rider dockets.

Q. WHAT IS THE COMPANY'S ESTIMATED RIDER REVENUE BY RECOVERY METHOD IN THE 2021 TEST YEAR?

A. Our proposed base rate and rider revenue recovery is shown in Table 6 below.

Table 6

Cost Recovery of Rider Projects

	2021 Test Year ($ in thousand)	
	RER Rider	TCR Rider
Rider Present Revenue	$14,297	$8,406
Revenue staying in Rider	$2,671	$(136)
Rider Revenue moved to Base Rates	$11,626	$8,542

15) RER Rider

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE RER RIDER IN THE 2021 TEST YEAR?

A. As described earlier, we propose to:

- Continue recovery of the Freeborn and Dakota Range Wind Farms in the RER Rider.

[1] In-serviced projects reflects any project that is expected to be placed in-service before 12/31/2020.

- Move Freeborn and Dakota Range Wind Farms to base rate recovery.

Q. PLEASE DESCRIBE THE RER RIDER REMOVAL ADJUSTMENT.

A. The RER Rider removal adjustment removes all costs and revenues from the test year jurisdictional cost of service for the wind farms that will continue cost recovery in the rider after the implementation of final rates in this case. The RER Rider test year adjustment ensures no double recovery of these costs. The adjustment has a net zero impact on the 2021 test year revenue requirements, as we expect full recovery in the RER rider. Support for the adjustment can be found on:

- Schedule 5, page 1, row 43, column 20,
- Schedule 6, page 1, row 39, column 20,
- Schedule 4, page 1, row 35, column 5
- Volume 3, Section VIII Adjustments, Tab A27.

As stated above, we propose to move Border, Courtenay, Foxtail, Blazing Star I and II, Lake Benton and Crowned Ridge Wind Farms into base rates at the conclusion of this case. Thus, no adjustment to test year costs is necessary for these projects. However, as costs for these projects will remain in the RER Rider during the period interim rates are in effect, an interim rate adjustment is necessary to ensure no double recovery of these costs during the interim rate period.

16) TCR Rider

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE TCR RIDER IN THE 2021 TEST YEAR?

A. We are proposing continued use of the TCR Rider during the rate plan period, which includes transmission projects and MISO RECB Schedule 26 and 26A revenues and expenses. In our 2021 TCR Rider filing, we requested recovery for a total of 58 projects that to date have not yet been included in base rates. With this filing, the 2021 test year reflects our proposal to move all in-serviced projects that are currently in the rider into base rates. The costs and revenues for the remaining ongoing transmission projects and MISO RECB would continue to remain in the TCR rider. Support for the complete list of projects we propose to move to base rates and remain in the rider can be found in Volume 3, Section VIII Adjustments, Tab A28.

Q. PLEASE DESCRIBE THE TCR RIDER REMOVAL ADJUSTMENT.

A. The TCR Rider removal adjustment removes all costs and revenues from the test year jurisdictional cost of service for the ongoing projects and MISO RECB that will continue cost recovery in the rider after the implementation of final rates in this case. The TCR Rider test year adjustment ensures no double recovery of these costs. The adjustment has a net zero impact on the 2021 test year revenue requirements, as we expect full recovery in the TCR rider. Support for the adjustment can be found on:

- Schedule 5, page 1, row 43, column 21,
- Schedule 6, page 1, row 39, column 21,
- Schedule 4, page 1, row 36, column 5
- Volume 3, Section VIII Adjustments, Tab A28.

As stated above, we propose to move all in-serviced projects into base rates at the conclusion of this case. Thus no adjustment to test year costs is necessary for these projects. However, as costs for these projects will remain in the TCR Rider during the period interim rates are in effect, an interim rate adjustment is necessary to ensure no double recovery of these costs during the interim rate period.

E. Secondary Cost of Service Calculations

17) ADIT Prorate – IRS Required

Q. PLEASE DESCRIBE THE ADIT PRORATE ADJUSTMENT THAT IS REQUIRED BY THE IRS AND INCLUDED IN THESE SECONDARY CALCULATIONS.

A. In general, the IRS tax regulations in Sec. 1.167(l) define a prorated schedule for the extent average accumulated deferred income taxes can be used to reduce rate base to comply with the tax normalization requirements of the Code when forecast information is used to set rates. Given that the Company's filing utilizes forecast test year data, this condition applies. This has been supported by a number of Private Letter Rulings (PLRs) issued by the IRS. In addition, FERC approved the proration logic included in the Company's Attachment O-NSP transmission formula rate of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff in Docket No. ER18-2322-000.

This secondary calculation limits the ADIT deduction from rate base by applying the IRS defined prorate method to only the forecast entries to this balance. During final validation on the ADIT prorate calculation, we identified that the prorate factor used in our model had inadvertently included a double average of the factor. This has been corrected in our interim rate petition and is discussed further in Section F below.

This adjustment impacts the 2021 test year revenue requirements by the amounts shown on:

- Schedule 5, page 1, row 43, column 22,

- Schedule 6, page 1, row 39, column 22,
- Schedule 4, page 1, row 39, column 5
- Volume 3, Section VIII Adjustments, Tab A29.

18) Impact of Adjustments on Cash Working Capital

Q. PLEASE DESCRIBE THE CASH WORKING CAPITAL ADJUSTMENT BEING MADE AS A SECONDARY CALCULATION.

A. As discussed earlier in Section IV.E, Other Rate Base, the Company has incorporated a secondary calculation to apply the various revenue lead days and expense lag days to the various income statement components to result in the appropriate cash working capital rate base adjustment.

This adjustment impacts the 2021 test year revenue requirements by the amounts shown on:

- Schedule 5, page 1, row 43, column 23,
- Schedule 6, page 1, row 39, column 23,
- Schedule 4, page 1, row 40, column 5
- Volume 3, Section VIII Adjustments, Tab A30.

19) Net Operating Loss

Q. PLEASE DESCRIBE THE COMPANY'S NET OPERATING LOSS POSITION.

A. The Company's income tax determination was in a net operating loss (NOL) position through 2020. This means that more deductions existed in the current period than are needed to bring current taxable income to zero. The Company still has federal and state tax credits that have been deferred and tracked for use in future periods.

NOLs, unused tax credits, and the associated ratemaking treatment are discussed in detail earlier in my testimony in Section V.D, Taxes.

Q. IS THE COMPANY PROPOSING AN ADJUSTMENT TO BASE RATES RELATED TO NOLS IN THIS CASE?

A. No. The Company was able to utilize the remainder of the deductions previously deferred and currently no NOL DTA is generated in the 2021 test year. As noted previously in my testimony, any changes in the revenues, expenses, or capital structure will cause the income tax calculation to be changed. This could in turn affect the timing of the DTAs being generated and added to rate base.

Q. IS THE COMPANY PROPOSING AN ADJUSTMENT TO BASE RATES RELATED TO DEFERRED TAX CREDITS IN THIS CASE?

A. Yes. The Company is utilizing federal tax credits during the 2021 test year, but due to the amount of federal tax credits earned during the year, the DTA is increasing. As noted previously in my testimony, any changes in the revenues, expenses, or capital structure will cause the income tax calculation to be changed. This could in turn affect the timing of the DTAs being generated or consumed and added to or removed from rate base. I note that the impact to the DTA was included in all modeling presented to the Commission in Case Nos. PU-12-813, PU-13-472, PU-15-181, and PU-17-120, in which the Commission granted ADPs for the Border, Courtenay, Foxtail, Blazing Star I and II, Lake Benton, and Crowned Ridge Wind projects.

This adjustment impacts the 2021 test year revenue requirements by the amounts shown on:

- Schedule 5, page 1, row 43, column 25,
- Schedule 6, page 1, row 39, column 25,
- Schedule 4, page 1, row 41, column 5
- Volume 3, Section VIII Adjustments, Tab A31.

20) Change in the Cost of Capital

Q. PLEASE DESCRIBE THE IMPACT OF THE CHANGE IN THE COST OF CAPITAL ADJUSTMENT.

A. The revenue requirements associated with the above adjustments described in this section of my testimony are calculated using the approved cost of capital in our last rate case. We calculate the revenue requirement impact of each adjustment at our currently authorized overall ROR of 7.72 percent (which includes the currently authorized ROE of 10.25 percent) so that changes in the overall cost of capital that occur during the duration of the rate case do not affect the revenue requirements for each adjustment. The change in cost of capital adjustment reflects the impact of the change in the approved ROR (7.72 percent) and proposed ROR (7.35 percent with a 10.20 percent ROE) for all of the rate base and income statement adjustments.

This adjustment impacts the 2021 test year revenue requirements by the amounts shown on:

- Schedule 5, page 1, row 43, column 24,
- Schedule 6, page 1, row 39, column 24,
- Volume 3, Section VIII Adjustments, Tab A32.

F. Rebuttal Adjustments

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION?

A. In this section, I provide details related to two adjustments we identified during our final quality assurance reviews performed just prior to this filing. These adjustments reflect small changes we believe are necessary but that we identified after we finalized our cost of service and rate design. Therefore, we were not able to incorporate these adjustments into the COSS due to timing constraints. We propose to incorporate these adjustments into the 2021 test year revenue requirement when we file Rebuttal Testimony.

21) FERC Audit

Q. PLEASE DESCRIBE THE REBUTTAL ADJUSTMENT RELATED TO THE FERC AUDIT.

A. The FERC audit of Xcel Energy Services Inc. (XES) identified an audit finding that impacts costs assigned to the Company, including the 2021 test year. The finding addressed the allocation of capital software to the Company's non-utility affiliates. Historically, capital costs related to software applications have been recorded to the Operating Companies, the primary users of the applications. As other affiliate companies receive indirect benefits of certain corporate software applications, the FERC finding required a retrospective adjustment as well as a prospective change in how software capital costs are recorded, ensuring that all Operating Companies and affiliates that receive direct or indirect benefits receive a portion of the capital charges.

Our interim rate petition has been corrected to include the adjustment to remove a portion of the software applications allocated to the Company related to this audit finding, and we will make the adjustment in Rebuttal Testimony for final rates. Support for this adjustment can be found in Volume 3, Workpapers, Section IX Interim, Tab Interim Adj 10.

22) ADIT Prorate for IRS

Q. PLEASE DESCRIBE THE REBUTTAL ADJUSTMENT RELATED TO ADIT PRORATE FOR IRS.

A. As discussed above, the Company was completing validation on the ADIT prorate calculation and identified that the pro-rate factor used in our model had inadvertently included a double averaging of the factor. This change will decrease the overall deficiency. Our interim rate petition has been corrected to include the correct prorate factor, and we will correct the factor in Rebuttal Testimony for final rates. Support for this adjustment can be found in Volume 3, Workpapers, Section VIII Adjustments, Tab A29.

23) RER PTC Amortization

Q. PLEASE DESCRIBE THE REBUTTAL ADJUSTMENT RELATED TO RER PTC AMORTIZATION.

A. As discussed above, the Company is proposing to use LCM to spread the PTC benefits to customers over the life of the applicable resource. However when completing a final validation on the PTC amounts in the COSS we identified that the adjustment inadvertently excluded Community Wind North, Jeffers and Mower Wind Farms from the calculation of the LCM. This change will increase the overall deficiency. Our interim rate petition has been corrected to include the correct LCM adjustment, and we will correct the rate case adjustment in Rebuttal Testimony for final rates. Support for this adjustment can be found in Volume 3, Workpapers, Section IX Interim, Tab Interim Adj 15.

VIII. COMPLIANCE MATTERS

Q. DID YOU REVIEW PRIOR COMMISSION ORDERS AS PART OF THE DEVELOPMENT OF THE TEST-YEAR REVENUE REQUIREMENT?

A. Yes. I describe below the various Commission Orders that were reviewed and addressed in preparing the test year. I discussed required adjustments related to each of these items earlier in my testimony. The Filing Requirements Compliance Table included in the testimony of Mr. Chamberlain, Exhibit___(GPC-1), Schedule 2, documents how our rate case filing includes information submitted in compliance with these prior Commission orders.

1) Long Term Incentive

In Case No. PU-400-92-399, the Commission determined that the costs of the Company's long-term incentive plan should be excluded from retail rates. Portions of Long-term incentive has been excluded from the test year as part of our incentive adjustment, which is discussed in Section VII of my testimony. However, as discussed in the Direct Testimony of Mr. Chamberlain, the Company is requesting recovery of the "environmental" portion of its Long Term Incentive Plan. I discuss the inclusion of these costs in our request above.

The Company has also removed all expenses associated with the Company's Supplemental Executive Retirement Plan (SERP) from its base data, which is consistent with prior Commission practice.

2) Organizational Dues

In Case No. PU-400-92-399, the Commission determined only organizational dues related to North Dakota electric operations were allowed recovery in electric rates. Any organizational dues not related to the electric operations supporting the State of North Dakota have been eliminated from the test year in our association dues adjustment.

3) Nuclear Refueling Costs

In Case No. PU-07-774, the Commission determined that nuclear refueling costs should be amortized over the life of the installed fuel. In our last two rate cases, the Commission determined an appropriate level for recovery using the deferral and amortization methodology. The Company is amortizing its nuclear refueling costs as ordered and has included an amortization expense in the 2021 test year reflecting the levelized accounting. The amortization is recognized in the budget.

4) Depreciation Lives

The 2021 budget for depreciation expense was based on the depreciation principles approved by the Commission in Case No. PU-07-776, as implemented in our last two rate cases. There are several changes to the approved lives, net salvage rates, and accruals that the Company is proposing in this proceeding for steam production, other production, transmission, distribution, and general plant for electric and common assets. The basis of the 2021 budget as well as the adjustments the Company is proposing in this case are further discussed by Mr. Moeller in his Direct Testimony. The related test year adjustments are discussed in Section VII of my testimony.

5) Expense Exclusions

In Case No. PU-07-776, the Commission ordered the following expenses be excluded from the test year recovery:

- Expenses related to Renewable Development Fund (RDF) Research and Development grants and disbursements.
- Costs associated with 50 percent of test-year charitable contributions.
- The amount of incentive compensation above the 15 percent cap included as part of the settlement in our last rate case.

The Company is adhering to the above items as follows:

- The Company has not included any RDF amortization expense in the test year.
- The Company has requested recovery of 50 percent of charitable contributions in the test year. Because these costs were budgeted below the line, we made an adjustment to include 50 percent of this expense, as discussed in Section VII of my testimony.
- In this case, the Company requests approval to cap the recovery of Annual Incentive Plan (AIP) compensation at 20 percent of any individual employee's base salary. Therefore, our test year incentive compensation adjustment made in Section VII of my testimony reflects recovery of these costs up to the 20 percent cap. However, since the Commission has previously only allowed recovery of annual incentive compensation up to 15 percent of any individual's base salary, we excluded the incremental difference from our determination of interim rate levels as outlined in our Interim Rate Petition.

6) Asset Based and Non-Asset Based Margin Sharing

In Case No. PU-07-776, as modified in Case No. PU-12-813, the Commission approved 100 percent of all asset-based wholesale margins and 50 percent of non-asset based margins being provided to ratepayers through the FCR Rider. Asset-based margins will be passed to customers each month through the true-up provisions of the monthly FCR. The non-asset based margins, if any, will be passed through the FCR in the subsequent year. The COSS includes an adjustment to remove all asset based and non-asset based margins from the base budget data in recognition of this sharing arrangement.

7) *Lobbying Expense*

Q. ARE ANY COSTS RELATED TO CIVIC OR POLITICAL ACTIVITIES (LOBBYING), IDENTIFIED IN THE COST OF SERVICE, OR ADJUSTMENTS?

A. No. Beginning in 1999, the Company moved all lobbying costs to below the line accounting, FERC account 426.4, Expenditures for certain civic, political, and related activities. Thus, no adjustment to the cost of service for lobbying is required, as these below the line amounts are not used in developing the cost of service.

8) *Pension Amortization*

Q. WHAT AMORTIZATION PERIOD IS THE COMPANY USING FOR UNRECOGNIZED PENSION COSTS?

A. Consistent with the Commission's order approving the Revised Second Amended Settlement in Case No. PU-12-813, the Company is amortizing pension costs based on an amortization period of approximately 20 years.

IX. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. I recommend that the Commission determine an overall retail revenue requirement of $228.644 million and 2021 revenue deficiency of $22.228 million for the Company's North Dakota jurisdictional electric operation, determined by the cost of service for the 2021 test year. I also recommend the Commission grant an interim rate increase of $16.358 million for the Company's North Dakota jurisdictional operation.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application of Northern States Power Company, a Minnesota Corporation For Authority to Increase Rates for Electric Service in North Dakota	))))	Case No. PU-20-___

AFFIDAVIT OF
Benjamin C. Halama

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Benjamin C Halama
Benjamin C. Halama

Subscribed and sworn to before me, this 21 day of October, 2020.

Steven D. Spiess
Notary Public
My Commission Expires: January 31, 2025

STEVEN DELMONT SPIESS
NOTARY PUBLIC
MINNESOTA
My Commission Expires Jan. 31, 2025

Resume of Benjamin C. Halama

Manager of Revenue Analysis
Revenue Requirements–North

Xcel Energy Services Inc.
414 Nicollet Mall
Minneapolis, MN 55401

Current Responsibilities

Since September 2018, I have worked as Manager of the Revenue Requirements–North department. In this position, I prepare and present cost of service studies, revenue requirement determinations, and jurisdictional annual reports for the electric and gas operations of Northern States Power Company to the North Dakota Public Service Commission, the Minnesota Public Utilities Commission, and the South Dakota Public Utilities Commission, and the Federal Energy Regulatory Commission.

Employment History

Xcel Energy – Minneapolis, MN

- Manager of Revenue Requirements–North, September 2018 to Present
- Manager Utility Accounting, May 2015 to August 2018

Target Corporation – Minneapolis, MN

- Manager of Inventory Accounting, 2014-2015
- Lead Analyst Financial Reporting, 2013-2014
- Supervisor Sales Accounting and Operations, 2011-2013

Copeland Buhl and Company – Wayzata, MN

- Accounting Supervisor, 2007-2011
- Senior Accountant, 2004-2007
- Staff Accountant, 2002-2004

Education

University of Wisconsin at Eau Claire, May 2002
Bachelor of Science in Accounting

Index of Schedules

	2021 Test Year		
	Total	ND Electric	Other
Composite Income Tax Rate			
State Tax Rate	4.31%	4.31%	4.31%
Federal Statuatory Tax Rate	21.00%	21.00%	21.00%
Federal Effective Tax Rate	20.09%	20.09%	20.09%
Composite Tax Rate	**24.40%**	**24.40%**	**24.40%**
Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.322837	1.322837	1.322837
Weighted Cost of Capital			
Active Rates and Ratios Version	Proposed	Proposed	Proposed
Cost of Short Term Debt	1.00%	1.00%	1.00%
Cost of Long Term Debt	4.22%	4.22%	4.22%
Cost of Common Equity	10.20%	10.20%	10.20%
Ratio of Short Term Debt	0.54%	0.54%	0.54%
Ratio of Long Term Debt	46.96%	46.96%	46.96%
Ratio of Common Equity	52.50%	52.50%	52.50%
Weighted Cost of STD	0.01%	0.01%	0.01%
Weighted Cost of LTD	1.98%	1.98%	1.98%
Weighted Cost of Debt	1.99%	1.99%	1.99%
Weighted Cost of Equity	5.36%	5.36%	5.36%
Required Rate of Return	**7.35%**	**7.35%**	**7.35%**
Rate Base			
Plant Investment	24,925,761,849	1,471,793,933	23,453,967,915
Depreciation Reserve	11,367,625,380	677,840,353	10,689,785,027
Net Utility Plant	13,558,136,468	793,953,580	12,764,182,888
CWIP	31,625,665	1,914,024	29,711,641
Accumulated Deferred Taxes	3,018,589,220	183,641,862	2,834,947,358
DTA - NOL Average Balance	(18,045,496)		(18,045,496)
DTA - State Tax Credit Average Balance	(354,137)	(31,860)	(322,277)
DTA - Federal Tax Credit Average Balance	(496,185,454)	(36,364,887)	(459,820,567)
Total Accum Deferred Taxes	2,504,004,132	147,245,114	2,356,759,018
Cash Working Capital	(144,517,160)	(7,103,092)	(137,414,068)
Materials and Supplies	174,923,376	10,806,596	164,116,780
Fuel Inventory	97,123,363	6,579,039	90,544,324
Non-plant Assets and Liabilities	88,306,992	8,415,116	79,891,876
Customer Advances	(9,169,912)	(62,381)	(9,107,531)
Customer Deposits	(44,930,376)	(71,274)	(44,859,102)
Prepaids and Other	80,616,733	5,159,576	75,457,157
Regulatory Amortizations	51,639,356	4,408,614	47,230,741
Total Other Rate Base Items	293,992,371	28,132,194	265,860,177
Total Rate Base	**11,379,750,372**	**676,754,684**	**10,702,995,688**

	2021 Test Year		
	Total	ND Electric	Other
Operating Revenues			
Retail	3,532,781,564	206,416,272	3,326,365,292
Interdepartmental	455,964		455,964
Other Operating Rev - Non-Retail	766,358,780	39,560,473	726,798,307
Total Operating Revenues	**4,299,596,308**	**245,976,745**	**4,053,619,563**
Expenses			
Operating Expenses:			
Fuel	1,035,810,318	56,396,304	979,414,013
Deferred Fuel			
Variable IA Production Fuel			
Purchased Energy - Windsource	6,003,946	0	6,003,946
Fuel & Purchased Energy Total	1,041,814,263	56,396,304	985,417,959
Production - Fixed	501,063,754	31,066,266	469,997,488
Production - Fixed IA Investment			
Production - Fixed IA O&M	49,291,953	3,042,842	46,249,111
Production - Variable	7,960,889	510,248	7,450,641
Production - Variable IA O&M	17,067,287	1,053,581	16,013,706
Production - Purchased Demand	160,569,589	9,827,919	150,741,670
Production Total	735,953,471	45,500,855	690,452,616
Regional Markets	11,099,571	685,188	10,414,384
Transmission IA	120,157,595	7,417,449	112,740,147
Transmission	268,574,522	10,151,545	258,422,977
Distribution	155,948,158	8,529,179	147,418,978
Customer Accounting	72,839,589	4,008,156	68,831,432
Customer Service & Information	112,693,003	284,060	112,408,942
Sales, Econ Dvlp & Other	467,488	118,859	348,629
Administrative & General	264,285,526	16,782,031	247,503,495
Total Operating Expenses	**2,783,833,187**	**149,873,628**	**2,633,959,559**
Depreciation	887,814,949	54,543,818	833,271,131
Amortization	16,059,958	6,231,557	9,828,401
Taxes:			
Property Taxes	216,754,203	11,495,109	205,259,093
ITC Amortization	(1,365,779)	(67,761)	(1,298,018)
Deferred Taxes	105,326,623	5,035,188	100,291,435
Deferred Taxes - NOL	2,174,287		2,174,287
Less State Tax Credits deferred	(82,279)	(63,720)	(18,559)
Less Federal Tax Credits deferred	(176,864,284)	(12,338,873)	(164,525,412)
Deferred Income Tax & ITC	(70,811,432)	(7,435,165)	(63,376,267)
Payroll & Other Taxes	32,033,321	2,031,768	30,001,552
Total Taxes Other Than Income	**177,976,092**	**6,091,712**	**171,884,379**

	2021 Test Year		
	Total	ND Electric	Other
Income Before Taxes			
Total Operating Revenues	4,299,596,308	245,976,745	4,053,619,563
less: Total Operating Expenses	2,783,833,187	149,873,628	2,633,959,559
Book Depreciation	887,814,949	54,543,818	833,271,131
Amortization	16,059,958	6,231,557	9,828,401
Taxes Other than Income	177,976,092	6,091,712	171,884,379
Total Before Tax Book Income	433,912,122	29,236,030	404,676,092
Tax Additions			
Book Depreciation	887,814,949	54,543,818	833,271,131
Deferred Income Taxes and ITC	(70,811,432)	(7,435,165)	(63,376,267)
Nuclear Fuel Burn (ex. D&D)	113,804,577	7,025,270	106,779,307
Nuclear Outage Accounting	45,490,790	2,952,752	42,538,038
Avoided Tax Interest	20,003,424	535,113	19,468,311
Other Book Additions	3,003,832	581,747	2,422,086
Total Tax Additions	999,306,141	58,203,535	941,102,606
Tax Deductions			
Total Rate Base	11,379,750,372	676,754,684	10,702,995,688
Weighted Cost of Debt	1.99%	1.99%	1.99%
Debt Interest Expense	226,457,032	13,467,418	212,989,614
Nuclear Outage Accounting	62,275,000	4,060,372	58,214,627
Tax Depreciation and Removals	1,501,937,963	86,872,952	1,415,065,012
NOL Utilized / (Generated)	7,735,143		7,735,143
Other Tax / Book Timing Differences	(1,864,323)	(282,512)	(1,581,811)
Total Tax Deductions	**1,796,540,815**	**104,118,230**	**1,692,422,585**
State Taxes			
State Taxable Income	(363,322,552)	(16,678,665)	(346,643,887)
State Income Tax Rate	4.31%	4.31%	4.31%
State Taxes before Credits	(15,659,202)	(718,850)	(14,940,352)
Less State Tax Credits applied	(1,104,721)	(9,555)	(1,095,166)
Total State Income Taxes	(16,763,923)	(728,406)	(16,035,518)
Federal Taxes			
Federal Sec 199 Production Deduction			
Federal Taxable Income	(346,558,629)	(15,950,259)	(330,608,369)
Federal Income Tax Rate	21.00%	21.00%	21.00%
Federal Tax before Credits	(72,777,312)	(3,349,554)	(69,427,758)
Less Federal Tax Credits	(5,554,070)	375,535	(5,929,604)
Total Federal Income Taxes	(78,331,382)	(2,974,020)	(75,357,362)
Total Taxes			
Total Taxes Other than Income	177,976,092	6,091,712	171,884,379
Total Federal and State Income Taxes	(95,095,305)	(3,702,425)	(91,392,880)
Total Taxes	82,880,786	2,389,287	80,491,499

	2021 Test Year		
	Total	ND Electric	Other
Total Operating Revenues	**4,299,596,308**	**245,976,745**	**4,053,619,563**
Total Expenses	**3,770,588,880**	**213,038,289**	**3,557,550,591**
AFDC Debt			
AFDC Equity			
Net Income	**529,007,427**	**32,938,456**	**496,068,972**
Rate of Return (ROR)			
Total Operating Income	529,007,427	32,938,456	496,068,972
Total Rate Base	11,379,750,372	676,754,684	10,702,995,688
ROR (Operating Income / Rate Base)	4.65%	4.87%	4.63%
Return on Equity (ROE)			
Net Operating Income	529,007,427	32,938,456	496,068,972
Debt Interest (Rate Base * Weighted Cost of Debt)	(226,457,032)	(13,467,418)	(212,989,614)
Earnings Available for Common	302,550,395	19,471,038	283,079,357
Equity Rate Base (Rate Base * Equity Ratio)	5,974,368,945	355,296,209	5,619,072,736
ROE (earnings for Common / Equity)	**5.06%**	**5.48%**	**5.04%**
Revenue Deficiency			
Required Operating Income (Rate Base * Required Return)	836,411,652	49,741,469	786,670,183
Net Operating Income	529,007,427	32,938,456	496,068,972
Operating Income Deficiency	307,404,225	16,803,013	290,601,211
Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.322837	1.322837	1.322837
Revenue Deficiency (Income Deficiency * Conversion Fact	**406,645,702**	**22,227,649**	**384,418,053**
Total Revenue Requirements			
Total Retail Revenues	3,533,237,528	206,416,272	3,326,821,256
Revenue Deficiency	406,645,702	22,227,649	384,418,053
Total Revenue Requirements	3,939,883,230	228,643,921	3,711,239,309

	2020 Current Year		
	Total	ND Electric	Other
Composite Income Tax Rate			
State Tax Rate	4.31%	4.31%	4.31%
Federal Statuatory Tax Rate	21.00%	21.00%	21.00%
Federal Effective Tax Rate	20.09%	20.09%	20.09%
Composite Tax Rate	**24.40%**	**24.40%**	**24.40%**
Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.322837	1.322837	1.322837
Weighted Cost of Capital			
Active Rates and Ratios Version	Proposed	Proposed	Proposed
Cost of Short Term Debt	2.83%	2.83%	2.83%
Cost of Long Term Debt	4.33%	4.33%	4.33%
Cost of Common Equity	10.20%	10.20%	10.20%
Ratio of Short Term Debt	0.23%	0.23%	0.23%
Ratio of Long Term Debt	47.27%	47.27%	47.27%
Ratio of Common Equity	52.50%	52.50%	52.50%
Weighted Cost of STD	0.01%	0.01%	0.01%
Weighted Cost of LTD	2.05%	2.05%	2.05%
Weighted Cost of Debt	2.06%	2.06%	2.06%
Weighted Cost of Equity	5.36%	5.36%	5.36%
Required Rate of Return	**7.42%**	**7.42%**	**7.42%**
Rate Base			
Plant Investment	23,063,587,347	1,382,840,759	21,680,746,588
Depreciation Reserve	10,563,873,002	628,176,803	9,935,696,200
Net Utility Plant	12,499,714,345	754,663,957	11,745,050,388
CWIP	43,837,178	2,803,602	41,033,576
Accumulated Deferred Taxes	2,973,922,834	179,757,729	2,794,165,105
DTA - NOL Average Balance	(21,020,876)	(662,406)	(20,358,469)
DTA - State Tax Credit Average Balance	(312,325)		(312,325)
DTA - Federal Tax Credit Average Balance	(379,208,082)	(27,050,266)	(352,157,817)
Total Accum Deferred Taxes	2,573,381,551	152,045,057	2,421,336,494
Cash Working Capital	(136,233,010)	(6,698,974)	(129,534,036)
Materials and Supplies	174,923,376	10,806,596	164,116,780
Fuel Inventory	97,123,363	6,579,039	90,544,324
Non-plant Assets and Liabilities	73,595,454	7,469,940	66,125,513
Customer Advances	(9,169,912)	(62,381)	(9,107,531)
Customer Deposits	(44,930,376)	(71,274)	(44,859,102)
Prepaids and Other	80,093,097	5,111,857	74,981,240
Regulatory Amortizations	56,136,694	6,483,867	49,652,827
Total Other Rate Base Items	291,538,685	29,618,670	261,920,015
Total Rate Base	**10,261,708,656**	**635,041,171**	**9,626,667,485**

	2020 Current Year		
	Total	ND Electric	Other
Operating Revenues			
Retail	3,646,679,025	206,637,042	3,440,041,983
Interdepartmental	452,982		452,982
Other Operating Rev - Non-Retail	751,802,165	40,858,902	710,943,263
Total Operating Revenues	**4,398,934,173**	**247,495,944**	**4,151,438,228**
Expenses			
Operating Expenses:			
Fuel	1,021,344,583	59,261,589	962,082,994
Deferred Fuel	(2,971,666)	(183,444)	(2,788,222)
Variable IA Production Fuel			
Purchased Energy - Windsource	7,111,409	0	7,111,409
Fuel & Purchased Energy Total	1,025,484,326	59,078,145	966,406,181
Production - Fixed	459,130,093	28,679,730	430,450,363
Production - Fixed IA Investment			
Production - Fixed IA O&M	38,306,429	2,364,694	35,941,735
Production - Variable	5,595,437	356,847	5,238,590
Production - Variable IA O&M	17,136,445	1,057,850	16,078,595
Production - Purchased Demand	143,694,708	8,870,418	134,824,290
Production Total	663,863,113	41,329,539	622,533,574
Regional Markets	10,833,967	668,792	10,165,175
Transmission IA	114,186,896	7,048,871	107,138,024
Transmission	252,910,599	9,703,626	243,206,973
Distribution	104,280,631	6,946,198	97,334,432
Customer Accounting	73,315,693	3,921,084	69,394,609
Customer Service & Information	105,777,115	259,856	105,517,259
Sales, Econ Dvlp & Other	1,436,164	203,163	1,233,001
Administrative & General	258,329,141	16,300,739	242,028,401
Total Operating Expenses	**2,610,417,645**	**145,460,014**	**2,464,957,631**
Depreciation	711,182,428	42,628,931	668,553,497
Amortization	5,482,606	3,060,520	2,422,086
Taxes:			
Property Taxes	203,106,645	10,841,338	192,265,306
ITC Amortization	(1,365,779)	(67,761)	(1,298,018)
Deferred Taxes	23,116,145	1,958,623	21,157,522
Deferred Taxes - NOL	5,632,922	2,859,872	2,773,049
Less State Tax Credits deferred	(1,345)		(1,345)
Less Federal Tax Credits deferred	(57,891,204)	(7,091,115)	(50,800,089)
Deferred Income Tax & ITC	(30,509,260)	(2,340,380)	(28,168,880)
Payroll & Other Taxes	31,255,778	1,985,221	29,270,557
Total Taxes Other Than Income	**203,853,162**	**10,486,179**	**193,366,983**

	2020 Current Year		
	Total	ND Electric	Other
Income Before Taxes			
Total Operating Revenues	4,398,934,173	247,495,944	4,151,438,228
less: Total Operating Expenses	2,610,417,645	145,460,014	2,464,957,631
Book Depreciation	711,182,428	42,628,931	668,553,497
Amortization	5,482,606	3,060,520	2,422,086
Taxes Other than Income	203,853,162	10,486,179	193,366,983
Total Before Tax Book Income	867,998,332	45,860,301	822,138,031
Tax Additions			
Book Depreciation	711,182,428	42,628,931	668,553,497
Deferred Income Taxes and ITC	(30,509,260)	(2,340,380)	(28,168,880)
Nuclear Fuel Burn (ex. D&D)	122,971,987	7,591,184	115,380,803
Nuclear Outage Accounting	47,070,290	3,041,045	44,029,245
Avoided Tax Interest	33,092,064	1,583,807	31,508,256
Other Book Additions	2,695,651	273,565	2,422,086
Total Tax Additions	886,503,159	52,778,152	833,725,007
Tax Deductions			
Total Rate Base	10,261,708,656	635,041,171	9,626,667,485
Weighted Cost of Debt	2.06%	2.06%	2.06%
Debt Interest Expense	211,391,198	13,081,848	198,309,350
Nuclear Outage Accounting	31,333,353	2,028,863	29,304,489
Tax Depreciation and Removals	1,095,545,751	67,064,373	1,028,481,378
NOL Utilized / (Generated)	20,039,423	10,174,150	9,865,273
Other Tax / Book Timing Differences	(18,894,019)	(941,569)	(17,952,450)
Total Tax Deductions	**1,339,415,707**	**91,407,665**	**1,248,008,041**
State Taxes			
State Taxable Income	415,085,785	7,230,788	407,854,997
State Income Tax Rate	4.31%	4.31%	4.31%
State Taxes before Credits	17,890,197	311,647	17,578,550
Less State Tax Credits applied	(1,185,655)	(73,275)	(1,112,381)
Total State Income Taxes	16,704,542	238,372	16,466,170
Federal Taxes			
Federal Sec 199 Production Deduction			
Federal Taxable Income	398,381,242	6,992,415	391,388,827
Federal Income Tax Rate	21.00%	21.00%	21.00%
Federal Tax before Credits	83,660,061	1,468,407	82,191,654
Less Federal Tax Credits	(64,631,162)	(1,208,428)	(63,422,734)
Total Federal Income Taxes	19,028,899	259,979	18,768,919
Total Taxes			
Total Taxes Other than Income	203,853,162	10,486,179	193,366,983
Total Federal and State Income Taxes	35,733,441	498,352	35,235,089
Total Taxes	239,586,603	10,984,530	228,602,072

	2020 Current Year		
	Total	ND Electric	Other
Total Operating Revenues	**4,398,934,173**	**247,495,944**	**4,151,438,228**
Total Expenses	**3,566,669,281**	**202,133,995**	**3,364,535,286**
AFDC Debt			
AFDC Equity			
Net Income	**832,264,891**	**45,361,949**	**786,902,942**
Rate of Return (ROR)			
Total Operating Income	832,264,891	45,361,949	786,902,942
Total Rate Base	10,261,708,656	635,041,171	9,626,667,485
ROR (Operating Income / Rate Base)	8.11%	7.14%	8.17%
Return on Equity (ROE)			
Net Operating Income	832,264,891	45,361,949	786,902,942
Debt Interest (Rate Base * Weighted Cost of Debt)	(211,391,198)	(13,081,848)	(198,309,350)
Earnings Available for Common	620,873,693	32,280,101	588,593,592
Equity Rate Base (Rate Base * Equity Ratio)	5,387,397,045	333,396,615	5,054,000,430
ROE (earnings for Common / Equity)	**11.52%**	**9.68%**	**11.65%**
Revenue Deficiency			
Required Operating Income (Rate Base * Required Return)	761,418,782	47,120,055	714,298,727
Net Operating Income	832,264,891	45,361,949	786,902,942
Operating Income Deficiency	(70,846,109)	1,758,106	(72,604,215)
Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.322837	1.322837	1.322837
Revenue Deficiency (Income Deficiency * Conversion Fact	**(93,717,858)**	**2,325,688**	**(96,043,546)**
Total Revenue Requirements			
Total Retail Revenues	3,647,132,007	206,637,042	3,440,494,965
Revenue Deficiency	(93,717,858)	2,325,688	(96,043,546)
Total Revenue Requirements	3,553,414,149	208,962,730	3,344,451,419

	2019 Actual Year		
	Total	ND Electric	Other
Composite Income Tax Rate			
State Tax Rate	4.31%	4.31%	4.31%
Federal Statuatory Tax Rate	21.00%	21.00%	21.00%
Federal Effective Tax Rate	20.09%	20.09%	20.09%
Composite Tax Rate	**24.40%**	**24.40%**	**24.40%**
Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.322837	1.322837	1.322837
Weighted Cost of Capital			
Active Rates and Ratios Version	Proposed	Proposed	Proposed
Cost of Short Term Debt	2.78%	2.78%	2.78%
Cost of Long Term Debt	4.49%	4.49%	4.49%
Cost of Common Equity	9.85%	9.85%	9.85%
Ratio of Short Term Debt	0.94%	0.94%	0.94%
Ratio of Long Term Debt	46.08%	46.08%	46.08%
Ratio of Common Equity	52.98%	52.98%	52.98%
Weighted Cost of STD	0.03%	0.03%	0.03%
Weighted Cost of LTD	2.07%	2.07%	2.07%
Weighted Cost of Debt	2.10%	2.10%	2.10%
Weighted Cost of Equity	5.22%	5.22%	5.22%
Required Rate of Return	**7.32%**	**7.32%**	**7.32%**
Rate Base			
Plant Investment	21,586,335,377	1,298,901,275	20,287,434,102
Depreciation Reserve	9,908,002,234	593,391,026	9,314,611,208
Net Utility Plant	11,678,333,143	705,510,250	10,972,822,894
CWIP	57,513,208	3,888,194	53,625,014
Accumulated Deferred Taxes	3,003,575,519	179,477,582	2,824,097,936
DTA - NOL Average Balance	(25,527,163)	(1,286,340)	(24,240,823)
DTA - State Tax Credit Average Balance	(182,177)		(182,177)
DTA - Federal Tax Credit Average Balance	(335,621,245)	(21,465,351)	(314,155,895)
Total Accum Deferred Taxes	2,642,244,933	156,725,892	2,485,519,042
Cash Working Capital			
Materials and Supplies	174,553,625	10,931,851	163,621,774
Fuel Inventory	84,959,156	5,601,017	79,358,139
Non-plant Assets and Liabilities	100,462,518	7,233,332	93,229,186
Customer Advances	(10,116,341)	(131,810)	(9,984,531)
Customer Deposits	(50,104,599)	(77,540)	(50,027,059)
Prepaids and Other	79,512,314	5,073,267	74,439,047
Regulatory Amortizations	100,737,382	5,881,961	94,855,420
Total Other Rate Base Items	480,004,055	34,512,079	445,491,977
Total Rate Base	**9,573,605,474**	**587,184,631**	**8,986,420,842**

	2019 Actual Year		
	Total	ND Electric	Other
Operating Revenues			
Retail	3,493,959,502	198,146,530	3,295,812,972
Interdepartmental	587,959		587,959
Other Operating Rev - Non-Retail	873,496,372	48,544,470	824,951,902
Total Operating Revenues	**4,368,043,833**	**246,691,000**	**4,121,352,833**
Expenses			
Operating Expenses:			
Fuel	1,112,278,117	63,708,797	1,048,569,319
Deferred Fuel	4,199,555	273,294	3,926,261
Variable IA Production Fuel	10,246,077	641,241	9,604,837
Purchased Energy - Windsource	7,324,156	0	7,324,156
Fuel & Purchased Energy Total	1,134,047,905	64,623,331	1,069,424,574
Production - Fixed	481,654,754	30,295,815	451,358,939
Production - Fixed IA Investment			
Production - Fixed IA O&M	45,143,188	2,825,241	42,317,947
Production - Variable	9,448,828	591,574	8,857,253
Production - Variable IA O&M	5,075,889	317,669	4,758,219
Production - Purchased Demand	127,450,370	7,976,354	119,474,016
Production Total	668,773,028	42,006,653	626,766,375
Regional Markets	10,651,251	666,598	9,984,653
Transmission IA	116,159,129	7,269,703	108,889,426
Transmission	263,569,552	9,942,832	253,626,721
Distribution	121,113,601	6,527,968	114,585,632
Customer Accounting	56,953,023	3,378,661	53,574,363
Customer Service & Information	111,747,345	424,778	111,322,566
Sales, Econ Dvlp & Other	137,919	2,917	135,003
Administrative & General	234,476,067	15,129,156	219,346,911
Total Operating Expenses	**2,717,628,820**	**149,972,597**	**2,567,656,223**
Depreciation	655,231,143	39,260,211	615,970,932
Amortization	(71,981,979)	(1,209,153)	(70,772,826)
Taxes:			
Property Taxes	209,304,570	11,083,821	198,220,749
ITC Amortization	(1,365,625)	(68,687)	(1,296,937)
Deferred Taxes	2,268,417	838,814	1,429,603
Deferred Taxes - NOL	(11,683,415)	5,619,938	(17,303,354)
Less State Tax Credits deferred	100,141		100,141
Less Federal Tax Credits deferred	8,008,852	(4,183,528)	12,192,380
Deferred Income Tax & ITC	(2,671,629)	2,206,537	(4,878,166)
Payroll & Other Taxes	31,372,832	2,019,416	29,353,416
Total Taxes Other Than Income	**238,005,773**	**15,309,775**	**222,695,999**

	2019 Actual Year		
	Total	ND Electric	Other
Income Before Taxes			
Total Operating Revenues	4,368,043,833	246,691,000	4,121,352,833
less: Total Operating Expenses	2,717,628,820	149,972,597	2,567,656,223
Book Depreciation	655,231,143	39,260,211	615,970,932
Amortization	(71,981,979)	(1,209,153)	(70,772,826)
Taxes Other than Income	238,005,773	15,309,775	222,695,999
Total Before Tax Book Income	829,160,076	43,357,570	785,802,505
Tax Additions			
Book Depreciation	655,231,143	39,260,211	615,970,932
Deferred Income Taxes and ITC	(2,671,629)	2,206,537	(4,878,166)
Nuclear Fuel Burn (ex. D&D)	118,969,264	7,445,572	111,523,691
Nuclear Outage Accounting	50,626,689	3,246,205	47,380,484
Avoided Tax Interest	28,306,372	1,865,447	26,440,925
Other Book Additions	5,579,730	273,565	5,306,165
Total Tax Additions	856,041,569	54,297,537	801,744,032
Tax Deductions			
Total Rate Base	9,573,605,474	587,184,631	8,986,420,842
Weighted Cost of Debt	2.10%	2.10%	2.10%
Debt Interest Expense	201,045,715	12,330,877	188,714,838
Nuclear Outage Accounting	60,744,756	3,902,612	56,842,144
Tax Depreciation and Removals	911,305,395	55,663,398	855,641,997
NOL Utilized / (Generated)	(41,564,382)	19,993,235	(61,557,617)
Other Tax / Book Timing Differences	15,677,092	899,911	14,777,181
Total Tax Deductions	**1,147,208,576**	**92,790,034**	**1,054,418,542**
State Taxes			
State Taxable Income	537,993,069	4,865,073	533,127,996
State Income Tax Rate	4.31%	4.31%	4.31%
State Taxes before Credits	23,187,501	209,685	22,977,817
Less State Tax Credits applied	(1,289,141)	(74,412)	(1,214,729)
Total State Income Taxes	21,898,360	135,272	21,763,088
Federal Taxes			
Federal Sec 199 Production Deduction			
Federal Taxable Income	516,094,709	4,729,801	511,364,908
Federal Income Tax Rate	21.00%	21.00%	21.00%
Federal Tax before Credits	108,379,889	993,258	107,386,631
Less Federal Tax Credits	(83,204,162)	(773,506)	(82,430,656)
Total Federal Income Taxes	25,175,727	219,752	24,955,975
Total Taxes			
Total Taxes Other than Income	238,005,773	15,309,775	222,695,999
Total Federal and State Income Taxes	47,074,087	355,024	46,719,063
Total Taxes	285,079,860	15,664,799	269,415,061

	2019 Actual Year		
	Total	ND Electric	Other
Total Operating Revenues	**4,368,043,833**	**246,691,000**	**4,121,352,833**
Total Expenses	**3,585,957,844**	**203,688,454**	**3,382,269,390**
AFDC Debt			
AFDC Equity			
Net Income	**782,085,989**	**43,002,546**	**739,083,443**
Rate of Return (ROR)			
Total Operating Income	782,085,989	43,002,546	739,083,443
Total Rate Base	9,573,605,474	587,184,631	8,986,420,842
ROR (Operating Income / Rate Base)	8.17%	7.32%	8.22%
Return on Equity (ROE)			
Net Operating Income	782,085,989	43,002,546	739,083,443
Debt Interest (Rate Base * Weighted Cost of Debt)	(201,045,715)	(12,330,877)	(188,714,838)
Earnings Available for Common	581,040,274	30,671,669	550,368,605
Equity Rate Base (Rate Base * Equity Ratio)	5,072,096,180	311,090,418	4,761,005,762
ROE (earnings for Common / Equity)	**11.46%**	**9.86%**	**11.56%**
Revenue Deficiency			
Required Operating Income (Rate Base * Required Return)	700,787,921	42,981,915	657,806,006
Net Operating Income	782,085,989	43,002,546	739,083,443
Operating Income Deficiency	(81,298,068)	(20,631)	(81,277,437)
Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.322837	1.322837	1.322837
Revenue Deficiency (Income Deficiency * Conversion Factor)	**(107,544,097)**	**(27,291)**	**(107,516,806)**
Total Revenue Requirements			
Total Retail Revenues	3,494,547,461	198,146,530	3,296,400,931
Revenue Deficiency	(107,544,097)	(27,291)	(107,516,806)
Total Revenue Requirements	3,387,003,363	198,119,239	3,188,884,125

2021 FTY ADJUSTMENT SUMMARY

(1) Line No.	(2) Record Category	(3) Report Label	(4) Record Type	(5) ND Electric 2021 Test Year	(6) Workpaper Reference
1	Unadjusted	Unadjusted	**Total Unadjusted**	**6,742,766**	
2					
3	Precedential	Precedential Adjustments	NSPM-Advertising (Trad)	(237,734)	A1
4	Precedential	Precedential Adjustments	NSPM-Assn Dues (Trad)	(21,599)	A2
5	Precedential	Precedential Adjustments	NSPM-Aviation	(99,354)	A3
6	Precedential	Precedential Adjustments	NSPM-Customer Deposits - A&G Expense (Trad)	1,618	A4
7	Precedential	Precedential Adjustments	NSPM-Employee Expenses	(81,941)	A5
8	Precedential	Precedential Adjustments	NSPM-Pension Non-Qual SERP Removal	(17,186)	A6
9	Precedential	Precedential Adjustments	NSPM-Remove Asset Trading	1,484,066	A7
10	Precedential	Precedential Adjustments	NSPM-Remove NonAsset Trading	95,278	A8
11	Precedential	Precedential Adjustments	NSPM-ND Electric Pension Extend Deferral	140,860	A9
12	Precedential		**Sub-Total Precedential**	**1,264,006**	
13					
14	Adjustment	Decommissioning	NSPM-ND Decommissioning	1,973,489	A10
15	Adjustment	Depreciation Study	NSPM-ND Depreciation Study Prod	3,413,218	A11
16	Adjustment	Depreciation Study	NSPM-ND Depreciation Study TD&G	317,743	A12
17	Adjustment	Economic Development Donations	NSPM-Econ Dev Donations (Trad)	102,803	A13
18	Adjustment	Foundation and Other Donations	NSPM-Donations (Trad)	68,443	A14
19	Adjustment	Incentive Compensation	NSPM-Incentive Pay	(129,995)	A15
20	Adjustment	Incentive Compensation	NSPM-Incentive Pay_Environmental LTI	151,707	A16
21	Adjustment	Incentive Compensation	NSPM-Incentive Pay_Remove Long Term	(1,123,650)	A17
22	Adjustment	Incentive Compensation	NSPM-Incentive Pay_Time Based LTI	94,917	A18
23	Adjustment	PI EPU Recovery	NSPM-ND PI EPU Deferral	487,574	A19
24	Adjustment	Dues: Chamber of Commerce	NSPM-Chamber of Commerce Dues	20,321	A20
25	Adjustment	Rider: RER	NSPM-RER PTC Amortization	4,427,516	A21
26	Adjustment	Non-Plant Excess ADIT	NSPM-Non-Plant Tax Reform Excess ADIT ND	31,879	A22
27	Adjustment		**Sub-Total Adjustment**	**9,835,966**	
28					
29	Amortization	Amortization	NSPM-Amortization ND RTF Study	184,302	A23
30	Amortization	Amortization	NSPM-ND Electric Income Tax Tracker Amortization	175,386	A24
31	Amortization	NOL ADIT ARAM	NSPM-NOL Tax Reform ADIT ARAM	846,307	A25
32	Amortization	Rate Case Expenses	NSPM-Amortization Rate Case Expense	419,372	A26
33	Amortization		**Sub-Total Amortization**	**1,625,367**	
34					
35	Rider Removals	Rider: RER	NSPM-RER Rider	-	A27
36	Rider Removals	Rider: TCR	NSPM-TCR-ND Rider Removal	-	A28
37	Rider Removals		**Sub-Total Rider Removals**	**-**	
38					
39	Secondary Calculations	ADIT Prorate for IRS	NSPM-ADIT Prorate for IRS	117,262	A29
40	Secondary Calculations	Cash Working Capital	NSPM-Cash Working Capital	(644,990)	A30
41	Secondary Calculations	Net Operating Loss	NSPM-NOL/Credits/199	3,287,272	A31
42	Secondary Calculations		**Sub-Total Secondary Calculations**	**2,759,544**	
43					
44			**Total Revenue Deficiency**	**22,227,649**	

2021 Test Year

Line No.	NSPM - 5 Bridge by Report Label	Bridge - Unadjusted					Precedential	Adjustment									
		Unadjusted	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Unadjusted at Last Authorized	Precedential Adjustments	Decommissioning	Depreciation Study	Dues: Chamber of Commerce	Economic Development Donations	Foundation and Other Donations	Incentive Compensation	Non-Plant Excess ADIT	PI EPU Recovery	Rider: RER PTC	Income Tax Tracker
1		(1)	(2)	(3)	(4)	(5)	(6) WP A1-A9	(7) WP A10	(8) WP A11-A12	(9) WP A20	(10) WP A13	(11) WP A14	(12) WP A15-A18	(13) WP A22	(14) WP A19	(15) WP A21	(16) WP A24
2	Plant as booked																
3	Production	905,744				905,744											
4	Transmission	247,845				247,845											
5	Distribution	213,025				213,025											
6	General	72,045				72,045											
7	Common	60,477				60,477											
8	Total Utility Plant in Service	1,499,134				1,499,134											
9																	
10	Reserve for Depreciation																
11	Production	469,658				469,658			2,211								
12	Transmission	60,469				60,469			284								
13	Distribution	80,070				80,070			257								
14	General	37,083				37,083			(112)								
15	Common	28,601				28,601			(210)								
16	Total Reserve for Depreciation	675,882				675,882			2,430								
17																	
18	Net Utility Plant																
19	Production	436,085				436,085			(2,211)								
20	Transmission	187,376				187,376			(284)								
21	Distribution	132,954				132,954			(257)								
22	General	34,962				34,962			112								
23	Common	31,875				31,875			210								
24	Net Utility Plant in Service	823,253				823,253			(2,430)								
25																	
26	Utility Plant Held for Future Use																
27																	
28	Construction Work in Progress	1,914				1,914											
29																	
30	Less: Accumulated Deferred Income Taxes	172,473	(2,599)		(25,638)	144,236	599		(683)					389	1,440		
31																	
32	Other Rate Base Items																
33	Cash Working Capital			(7,969)		(7,969)											
34	Materials and Supplies	10,807				10,807											
35	Fuel Inventory	6,579				6,579											
36	Non Plant Assets and Liabilities	6,286				6,286	2,129										
37	Customer Advances	(62)				(62)											
38	Customer Deposits	(71)				(71)											
39	Prepayments	5,160				5,160											
40	Regulatory Amortizations														3,955	(5,239)	357
41	Total Other Rate Base	28,697		(7,969)		20,728	2,129								3,955	(5,239)	357
42																	
43	Total Average Rate Base	681,391	2,599	(7,969)	25,638	701,659	1,531		(1,747)					(389)	2,515	(5,239)	357

Northern States Power Company
State of North Dakota Electric Jurisdiction

Case No. PU-20-____
Exhibit___(BCH-1) Schedule 5
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2021 Test Year

Line No.	NSPM - 5 Bridge by Report Label	Amortization			Rider Removals		Secondary Calculations				Total
		ND RTF Amortization	NOL ADIT ARAM	Rate Case Expenses	Rider: RER	Rider: TCR	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss	
		(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)
1		WP A23	WP A25	WP A26	WP A27	WP A28	WP A29	WP A30	WP A32	WP A31	
2	Plant as booked										
3	Production				(19,807)						885,937
4	Transmission				(613)	(6,912)					240,321
5	Distribution										213,025
6	General					(10)					72,035
7	Common										60,477
8	Total Utility Plant in Service				(20,419)	(6,921)					1,471,794
9											
10	Reserve for Depreciation										
11	Production				(341)						471,529
12	Transmission				(4)	(126)					60,624
13	Distribution										80,327
14	General					(1)					36,969
15	Common										28,392
16	Total Reserve for Depreciation				(344)	(128)					677,840
17											
18	Net Utility Plant										
19	Production				(19,466)						414,408
20	Transmission				(609)	(6,786)					179,697
21	Distribution										132,698
22	General					(8)					35,066
23	Common										32,085
24	Net Utility Plant in Service				(20,075)	(6,794)					793,954
25											
26	Utility Plant Held for Future Use										
27											
28	Construction Work in Progress										1,914
29											
30	Less: Accumulated Deferred Income Taxes				(839)	(197)	1,308			993	147,245
31											
32	Other Rate Base Items										
33	Cash Working Capital							866			(7,103)
34	Materials and Supplies										10,807
35	Fuel Inventory										6,579
36	Non Plant Assets and Liabilities										8,415
37	Customer Advances										(62)
38	Customer Deposits										(71)
39	Prepayments										5,160
40	Regulatory Amortizations		5,335								4,409
41	Total Other Rate Base		5,335					866			28,132
42											
43	Total Average Rate Base		5,335		(19,235)	(6,596)	(1,308)	866		(993)	676,755

2021 Test Year

Line No.	NSPM - 6 Bridge by Report Label	Bridge - Unadjusted					Precedential	Adjustment									Amortization			
		Unadjusted	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Unadjusted at Last Authorized	Precedential Adjustments	Decommissioning	Depreciation Study	Dues: Chamber of Commerce	Economic Development Donations	Foundation and Other Donations	Incentive Compensation	Non-Plant Excess ADIT	PI EPU Recovery	Rider: RER PTC	Income Tax Tracker	ND RTF Amortization	NOL ADIT ARAM	Rate Case Expenses
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
(1)							WP A1-A9	WP A10	WP A11-A12	WP A20	WP A13	WP A14	WP A15-A18	WP A22	WP A19	WP A21	WP A24	WP A23	WP A25	WP A26
(2)																				
(3)	Operating Revenues																			
(4)	Retail Revenue	208,952				208,952														
(5)	Other Operating	69,403				69,403	(22,824)		733											
(6)	Total Revenue	278,355				278,355	(22,824)		733											
(7)																				
(8)	Expenses																			
(9)	Operating Expenses																			
(10)	Fuel & Purchased Energy	77,641				77,641	(21,245)													
(11)	Power Production	46,740				46,740							(271)							
(12)	Transmission	24,420				24,420														
(13)	Distribution	8,529				8,529														
(14)	Customer Accounting	4,008				4,008														
(15)	Customer Service and Information	284				284														
(16)	Sales, Econ Dev, & Other	16				16					103									
(17)	Administrative and General	17,885				17,885	(455)			20		68	(736)							
(18)	Total Operating Expenses	179,523				179,523	(21,700)			20	103	68	(1,007)							
(19)																				
(20)	Depreciation	48,499				48,499		1,973	4,861											
(21)	Amortization														308	4,903	143	184	274	419
(22)																				
(23)	Taxes																			
(24)	Property	11,603				11,603														
(25)	Deferred Income Tax and ITC	8,446			(13,868)	(5,422)	11		(1,366)					51	(112)					
(26)	Federal and State Income Tax	(16,492)	(15)	45	13,521	(2,940)	(292)	(482)	189	(5)	(25)	(17)	246	2	(14)	(1,167)	(37)	(45)	(30)	(102)
(27)	Payroll and Other	2,033				2,033	(1)													
(28)	Total Taxes	5,589	(15)	45	(347)	5,273	(282)	(482)	(1,177)	(5)	(25)	(17)	246	53	(127)	(1,167)	(37)	(45)	(30)	(102)
(29)																				
(30)	Total Expenses	233,611	(15)	45	(347)	233,295	(21,982)	1,492	3,683	15	78	52	(761)	53	182	3,736	106	139	243	317
(31)																				
(32)	Allowance for Funds Used During Construct																			
(33)																				
(34)	Net Income	44,744	15	(45)	347	45,060	(842)	(1,492)	(2,950)	(15)	(78)	(52)	761	(53)	(182)	(3,736)	(106)	(139)	(243)	(317)
(35)																				
(36)	Calculation of Revenue Requirements																			
(37)	Rate Base	681,391	2,599	(7,969)	25,638	701,659	1,531		(1,747)					(389)	2,515	(5,239)	357		5,335	
(38)	Required Operating Income	52,603	201	(615)	1,979	54,168	118		(135)					(30)	194	(404)	28		412	
(39)	Operating Income	44,744	15	(45)	347	45,060	(842)	(1,492)	(2,950)	(15)	(78)	(52)	761	(53)	(182)	(3,736)	(106)	(139)	(243)	(317)
(40)	Income Deficiency	7,860	186	(570)	1,632	9,108	960	1,492	2,815	15	78	52	(761)	23	376	3,332	134	139	655	317
(41)	**Revenue Deficiency**	**10,397**	**246**	**(754)**	**2,159**	**12,048**	**1,270**	**1,973**	**3,724**	**20**	**103**	**68**	**(1,007)**	**30**	**497**	**4,408**	**177**	**184**	**867**	**419**
(42)																				
(43)	Calculation of Income Taxes																			
(44)	Operating Revenue	278,355				278,355	(22,824)		733											
(45)	-Operating Expense	179,523				179,523	(21,700)			20	103	68	(1,007)							
(46)	-Amortization														308	4,903	143	184	274	419
(47)	-Taxes Other then Income	22,082			(13,868)	8,213	10		(1,366)					51	(112)					
(48)	Operating Income Before Adjs	76,750			13,868	90,619	(1,134)		2,099	(20)	(103)	(68)	1,007	(51)	(196)	(4,903)	(143)	(184)	(274)	(419)
(49)	Additions to Income	19,626			(13,868)	5,758	11		(1,366)					51	196				274	
(50)	Deductions from Income	97,091			(5,015)	92,076	38	1,973												
(51)	Debt Synchonization	15,876	61	(186)	597	16,349	36		(41)					(9)	59	(122)	8		124	
(52)	State Taxable Income	(16,591)	(61)	186	4,418	(12,048)	(1,197)	(1,973)	774	(20)	(103)	(68)	1,007	9	(59)	(4,781)	(151)	(184)	(124)	(419)
(53)	State Income Tax Before Credits	(715)	(3)	8	190	(519)	(52)	(85)	33	(1)	(4)	(3)	43	0	(3)	(206)	(7)	(8)	(5)	(18)
(54)	State Tax Credits	(73)			73															
(55)	Federal Tax Deductions																			
(56)	Federal Taxable Income	(15,803)	(58)	178	4,154	(11,529)	(1,145)	(1,888)	740	(19)	(98)	(65)	964	9	(56)	(4,575)	(145)	(176)	(119)	(401)
(57)	Federal Income Tax Before Credits	(3,319)	(12)	37	872	(2,421)	(240)	(397)	155	(4)	(21)	(14)	202	2	(12)	(961)	(30)	(37)	(25)	(84)
(58)	Federal Tax Credits	(12,385)			12,385															
(59)	Total Income Taxes	(16,492)	(15)	45	13,521	(2,940)	(292)	(482)	189	(5)	(25)	(17)	246	2	(14)	(1,167)	(37)	(45)	(30)	(102)

2021 Test Year

Line No.	NSPM - 6 Bridge by Report Label	Rider Removals: Rider: RER	Rider Removals: Rider: TCR	Secondary Calculations: ADIT Prorate for IRS	Secondary Calculations: Cash Working Capital	Secondary Calculations: Change in Cost of Capital	Secondary Calculations: Net Operating Loss	Total
		(20)	(21)	(22)	(23)	(24)	(25)	(26)
(1)		WP A27	WP A28	WP A29	WP A30	WP A32	WP A31	
(2)								
(3)	Operating Revenues							
(4)	Retail Revenue	(2,671)	136					206,416
(5)	Other Operating		(7,751)					39,560
(6)	Total Revenue	(2,671)	(7,615)					245,977
(7)								
(8)	Expenses							
(9)	Operating Expenses							
(10)	Fuel & Purchased Energy							56,396
(11)	Power Production	(283)						46,186
(12)	Transmission		(6,851)					17,569
(13)	Distribution							8,529
(14)	Customer Accounting							4,008
(15)	Customer Service and Information							284
(16)	Sales, Econ Dev, & Other							119
(17)	Administrative and General							16,782
(18)	Total Operating Expenses	(283)	(6,851)					149,874
(19)								
(20)	Depreciation	(686)	(103)					54,544
(21)	Amortization							6,232
(22)								
(23)	Taxes							
(24)	Property	(66)	(41)					11,495
(25)	Deferred Income Tax and ITC	(1,940)	(121)				1,466	(7,435)
(26)	Federal and State Income Tax	1,734	(9)	7	(5)	562	(1,272)	(3,702)
(27)	Payroll and Other							2,032
(28)	Total Taxes	(273)	(171)	7	(5)	562	193	2,389
(29)								
(30)	Total Expenses	(1,242)	(7,125)	7	(5)	562	193	213,038
(31)								
(32)	Allowance for Funds Used During Construct							
(33)								
(34)	Net Income	(1,430)	(490)	(7)	5	(562)	(193)	32,938
(35)								
(36)	Calculation of Revenue Requirements							
(37)	Rate Base	(19,235)	(6,596)	(1,308)	866		(993)	676,755
(38)	Required Operating Income	(1,485)	(509)	(101)	67	(2,504)	(77)	49,741
(39)	Operating Income	(1,430)	(490)	(7)	5	(562)	(193)	32,938
(40)	Income Deficiency	(55)	(19)	(94)	62	(1,942)	117	16,803
(41)	**Revenue Deficiency**	**(73)**	**(25)**	**(124)**	**82**	**(2,570)**	**154**	**22,228**
(42)								
(43)	Calculation of Income Taxes							
(44)	Operating Revenue	(2,671)	(7,615)					245,977
(45)	-Operating Expense	(283)	(6,851)					149,874
(46)	-Amortization							6,232
(47)	-Taxes Other then Income	(2,007)	(163)				1,466	6,092
(48)	Operating Income Before Adjs	(382)	(602)				(1,466)	83,780
(49)	Additions to Income	(2,480)	(249)				1,466	3,660
(50)	Deductions from Income	(7,790)	(662)				5,015	90,651
(51)	Debt Synchonization	(448)	(154)	(30)	20	(2,301)	(23)	13,467
(52)	State Taxable Income	5,377	(35)	30	(20)	2,301	(4,992)	(16,679)
(53)	State Income Tax Before Credits	232	(2)	1	(1)	99	(215)	(719)
(54)	State Tax Credits						(10)	(10)
(55)	Federal Tax Deductions							
(56)	Federal Taxable Income	5,145	(34)	29	(19)	2,202	(4,767)	(15,950)
(57)	Federal Income Tax Before Credits	1,080	(7)	6	(4)	462	(1,001)	(3,350)
(58)	Federal Tax Credits	422					(47)	376
(59)	Total Income Taxes	1,734	(9)	7	(5)	562	(1,272)	(3,702)

($000's)

Line	Description	Adjusted Proposed Test Year 2021
1	Average Rate Base	$676,755
2	Operating Income (Before AFUDC)	$32,938
3	Allowance for Funds Used During Construction	$0
4	Total Available for Return (Line 2 + Line 3 + Rounding)	$32,938
5	Overall Rate of Return (Line 4 / Line 1)	4.87%
6	Required Rate of Return	7.35%
7	Operating Income Requirement (Line 1 x Line 6)	$49,741
8	Income Deficiency (Line 7 - Line 4)	$16,803
9	Gross Revenue Conversion Factor	1.32284
10	Revenue Deficiency (Line 8 x Line 9)	$22,228
11	Retail Related Revenue Under Present Rates	$206,416
12	Percentage Increase Needed in Overall Revenue (Line 10 / Line 11)	10.77%

Northern States Power Company
Electric Utility - State of North Dakota
Test Year Ending December 31, 2021
Cash Working Capital Summary

Case No. PU-20-____
Exhibit____(BCH-1), Schedule 8

Line No.	Summary Cash Working Capital		Lead/Lag	Total		ND Electric		Other	
			Days	Dollars	Dollar x Days	Dollars	Dollar x Days	Dollars	Dollar x Days
1	**Fuel Expenses**								
2	Coal and Rail Transport		19.13	150,943	2,887,536	10,225	195,599	140,718	2,691,937
3	Gas for Generation		39.34	183,487	7,218,381	12,133	477,306	171,354	6,741,075
4	Oil		11.50	14	163	1	11	13	152
5	Nuclear and EOL		-	114,842		7,779		107,063	
6	Nuclear Disposal		-						
7	**Subtotal Fuel Expenses**			**449,286**	**10,106,080**	**30,138**	**672,915**	**419,149**	**9,433,165**
8									
9	**Purchased Power**								
10	Purchases		39.69	708,062	28,102,984	33,163	1,316,226	674,899	26,786,758
11	Interchange		37.29	186,517	6,955,213	11,514	429,352	175,003	6,525,861
12	**SubTotal Purchased Power**			**894,579**	**35,058,197**	**44,677**	**1,745,578**	**849,902**	**33,312,619**
13									
14	**Labor and Related**								
15	Regular Payroll		11.90	435,152	5,178,310	26,917	320,317	408,235	4,857,993
16	Incentive		248.78	16,296	4,054,036	1,007	250,531	15,289	3,803,505
17	Pension and Benefits		37.29	78,123	2,913,205	4,998	186,359	73,125	2,726,846
18	**SubTotal Labor and Related**			**529,571**	**12,145,551**	**32,922**	**757,207**	**496,649**	**11,388,344**
19									
20	All Other Operating Expenses		39.25	917,531	36,013,077	49,271	1,933,880	868,260	34,079,197
21	Property taxes		356.83	216,862	77,382,867	11,603	4,140,265	205,259	73,242,602
22	Employer's Payroll Taxes		30.14	32,033	965,484	2,032	61,237	30,002	904,247
23	Gross Earnings Tax		41.13	94,487	3,886,239	3,829	157,468	90,658	3,728,771
24	Federal Income Tax		37.50	(78,373)	(2,938,984)	(4,452)	(166,941)	(73,921)	(2,772,043)
25	State Income Tax		37.50	(16,682)	(625,587)	(955)	(35,806)	(15,727)	(589,781)
26	State Sales Tax Customer Billings		-	142,360	6,577,020			142,360	6,577,020
27	**Total Expenses**	A		**3,181,653**	**178,569,945**	**169,064**	**9,265,804**	**3,012,590**	**169,304,141**
28	Net Annual Expense			56.12	489,233	54.81	25,386	56.20	463,847
29									
30	**Revenues**								
31	Retail Revenue		40.55	3,542,464	143,646,934	208,952	8,472,984	3,333,513	135,173,950
32	Late Payment		-	6,366		436		5,930	
33	Interdepartmental		-	456				456	
34	Misc Services		40.55	3,873	157,062	448	18,159	3,425	138,903
35	CIP Incentive		-	(1,503)				(1,503)	
36	Rentals		(100.20)	5,345	(535,556)	334	(33,503)	5,011	(502,053)
37	Interchange		37.29	478,705	17,850,905	29,551	1,101,954	449,154	16,748,950
38	Sales for Resale		34.06	833	28,363	522	17,788	310	10,574
39	Retail Rev Lag Days		40.55	23,144	938,474	84	3,400	23,060	935,074
40	MISO		14.00	6,870	96,183	424	5,937	6,446	90,246
41	Wholesale Lag Days		34.06	250,477	8,531,239	15,512	528,345	234,965	8,002,894
42	**Total Revenues**	B		**4,317,031**	**170,713,603**	**256,263**	**10,115,066**	**4,060,767**	**160,598,538**
46	Net Annual Amount			39.54	467,709	39.47	27,713	39.55	439,996
47	Expense/Revenue Factor	C = A/B					65.97%		
48	Allocated Revenue Amount	D = B * C				-	18,283		
49	**Net Cash Working Capital**	E = D - A					**(7,103)**		

DETAILED CASE DRIVERS
Test Year Drivers - Revenue Requirements
Amounts in millions

	Increase (Decrease) 2021 TY to 2013 TY	Increase (Decrease) 2021 TY to 2019 Actual
Capital Related		
Nuclear	8.3	(0.0)
Nuclear Decommissioning Trust	2.0	2.0
Steam	0.3	0.2
Remaining Life Adjustment	3.4	3.4
Wind	17.4	11.8
All Other Production	0.8	0.4
Transmission	6.6	1.0
Distribution	6.5	1.6
General and Intangible	7.2	1.0
DTA (Federal Credits & NOL)	1.1	1.0
Other Rate Base	0.6	(0.5)
TOTAL Capital Related	54.3	22.0
Amortizations	6.0	7.4
Taxes		
Taxes - Other	(5.3)	(1.3)
PTCs	(12.0)	(7.0)
Property Tax	3.4	0.4
Payroll Tax	0.1	0.0
TOTAL Taxes	(13.8)	(7.8)
Operating Expense		
Nuclear	(1.0)	(0.4)
Steam	(2.9)	(0.8)
Wind	2.8	1.9
Purchased Demand	(0.3)	1.9
All Other Production	(0.4)	0.3
Transmission	0.0	0.2
Transmission Interchange	3.5	0.1
Distribution	1.8	2.0
Regional Markets	0.7	0.0
Customer Accounting / Info / Service	(0.3)	0.6
A&G	2.8	1.7
TOTAL O&M	6.6	7.5
Other Margin Impacts		
Sales Change	4.9	2.7
Net settlement revenue	(15.7)	-
Rider Revenue	(20.2)	(13.3)
15 CBED and 7 Solar PPAs	-	2.6
Other	(0.7)	1.1
TOTAL Other Margin Impacts	(31.6)	(6.9)
TOTAL Net Incremental Deficiency	**21.4**	**22.3**

Budgeting Accuracy

NSPM Total Company Actual versus Budget Capital Expenditures ($millions)

Year	Budget Amount	Actual Amount	$ Variance	% Variance
2019	$2,132.78	$1,470.90	($661.37)*	(31.02%)
2018	$1,373.8	$1,333.5	($40.2)	(2.9%)
2017	$1,104.7	$946.2	($158.5)**	(14.3%)
2017-2019 Total	**$3,662.5**	**$3,463.9**	**($198.6)**	**(5.4%)**

*Variance due to timing of in-servicing Crowned Ridge, Jeffers, Community Wind North, Blazing Star I and II and Freeborn wind projects due to permitting delays and in-service date changes. All projects have now been placed in service.

**$157 million of variance due to timing of wind farm spend. The original 2017 budget assumed that wind projects that used safe harbor turbines would take possession of them upon approval of the projects. However, possession of the turbines was taken upon delivery, which resulted in a shift of costs from 2017 into later years. The costs were ultimately paid by the Company.

NSPM Total Company Actual versus Budget O&M ($millions)

Year	Budget Amount	Actual Amount	$ Variance	% Variance
2019	$1,194.4	$1,203.1	$8.7	0.7%
2018	$1,204.9	$1,223.3	$18.4	1.5%
2017	$1,209.0	$1,213.1	$4.1	0.3%
Three-Year Total	**$3,608.3**	**$3,639.5**	**$31.2**	**0.9%**

NSPM Electric Utility Actual versus Budget O&M ($millions)

Year	Budget Amount	Actual Amount	$ Variance	% Variance
2019	$1,101.2	$1,109.5	$8.3	0.7%
2018	$1,117.2	$1,115.4	($1.8)	(0.2%)
2017	$1,119.7	$1,113.5	($6.2)	(0.6%)
Three-Year Total	**$3,338.1**	**$3,338.4**	**($0.3)**	**(0.0%)**

OPERATING REVENUES, OPERATING EXPENSE,
TOTAL AVAILABLE FOR RETURN WITH PRESENT AND FINAL RATES
(000's)

Line No.	Description	Test Year Ending 12/31/21 Present Rates	Final Increase	Test Year Ending 12/31/21 Final Rates
		(A)	(B)	(C) = (B) + (A)
	Operating Revenues			
1	Retail	$206,416	$22,228	$228,644
2	CIP Revenue Adjustment	0		0
3	Interdepartmental	0		0
4	Other Operating	39,560		39,560
5	Gross Earnings Tax	0		0
6	Total Operating Revenues	$245,977	$22,228	$268,205
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	$56,396		$56,396
8	Power Production	45,501		45,501
9	Transmission	18,254		18,254
10	Distribution	8,529		8,529
11	Customer Accounting	4,008		4,008
12	Customer Service & Information	284		284
13	Sales, Econ Dvlp & Other	119		119
14	Administrative & General	16,782		16,782
15	Total Operating Expenses	$149,874	$0	$149,874
16	Depreciation	$54,544		$54,544
17	Amortizations	6,232		6,232
	Taxes:			
18	Property	$11,495		$11,495
19	Gross Earnings	0		0
20	Deferred Income Tax & ITC	(7,435)		(7,435)
21	Federal & State Income Tax	(3,702)	5,425	1,722
22	Payroll & Other	2,032		2,032
23	Total Taxes	$2,389	$5,425	$7,814
24	Total Expenses	$213,038	$5,425	$218,463
25	AFUDC	$0	$0	$0
26	Total Operating Income	$32,938	$16,803	$49,741

Statement of Operating Income
(000's)

Line No.	Description	2021 Test Year Unadjusted	Adjustments	2021 Test Year Adjusted
		(H)	(I)	(J)
	Operating Revenues			(Col F + G)
1	Retail	$208,952	($2,535)	$206,416
2	CIP Adjustment to Program Costs	0	0	0
3	Interdepartmental	0	0	0
4	Other Operating	69,403	(29,843)	39,560
5	Gross Earnings Tax	0	0	0
6	Total Operating Revenues	$278,355	($32,378)	$245,977
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	$77,641	($21,245)	$56,396
8	Power Production	46,055	(554)	45,501
9	Transmission	25,105	(6,851)	18,254
10	Distribution	8,529	0	8,529
11	Customer Accounting	4,008	0	4,008
12	Customer Service & Information	284	0	284
13	Sales, Econ Dvlp & Other	16	103	119
14	Administrative & General	17,861	(1,079)	16,782
15	Total Operating Expenses	$179,499	($29,626)	$149,874
16	Depreciation	$48,499	$6,045	$54,544
17	Amortizations	$0	$6,232	$6,232
	Taxes:			
18	Property	$11,603	($108)	$11,495
19	Gross Earnings	0	0	0
20	Deferred Income Tax & ITC	(5,509)	(1,926)	(7,435)
21	Federal & State Income Tax	(2,276)	(1,426)	(3,702)
22	Payroll & Other	2,032	(0)	2,032
23	Total Taxes	$5,850	($3,461)	$2,389
24	Total Expenses	$233,848	($20,810)	$213,038
25	Allowance for Funds Used During Construction	$0	$0	$0
26	Total Operating Income	$44,507	($11,568)	$32,938

OPERATING REVENUES, OPERATING EXPENSE,
TOTAL AVAILABLE FOR RETURN WITH PRESENT AND FINAL RATES
(000's)

Line No.	Description	Bridge Ending 12/31/20 Present Rates	Final Increase	Bridge Ending 12/31/20 Final Rates
		(A)	(B)	(C) = (B) + (A)
	Operating Revenues			
1	Retail	$206,637	$2,326	$208,963
2	CIP Revenue Adjustment	$0		0
3	Interdepartmental	$0		0
4	Other Operating	$40,859		40,859
5	Gross Earnings Tax	$0		0
6	Total Operating Revenues	$247,496	$2,326	$249,823
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	$59,078		$59,078
8	Power Production	$41,330		41,330
9	Transmission	$17,421		17,421
10	Distribution	$6,946		6,946
11	Customer Accounting	$3,921		3,921
12	Customer Service & Information	$260		260
13	Sales, Econ Dvlp & Other	$203		203
14	Administrative & General	$16,301		16,301
15	Total Operating Expenses	$145,460	$0	$145,460
16	Depreciation	$42,629		$42,629
17	Amortizations	$3,061		3,061
	Taxes:			
18	Property	$10,841		$10,841
19	Gross Earnings	$0		0
20	Deferred Income Tax & ITC	($2,340)		(2,340)
21	Federal & State Income Tax	$498	568	1,066
22	Payroll & Other	$1,985		1,985
23	Total Taxes	$10,985	$568	$11,552
24	Total Expenses	$202,134	$568	$202,702
25	AFUDC	$0	$0	$0
26	Total Operating Income	$45,362	$1,758	$47,120

Northern States Power Company
Electric Utility - State of North Dakota

Statement of Operating Income
(000's)

Line No.	Description	2020 Bridge Year Unadjusted	Adjustments	2020 Bridge Year Adjusted
		(H)	(I)	(J)
	Operating Revenues			(Col F + G)
1	Retail	$206,878	($241)	$206,637
2	CIP Adjustment to Program Costs	0	0	0
3	Interdepartmental	0	0	0
4	Other Operating	54,304	(13,445)	40,859
5	Gross Earnings Tax	0	0	0
6	Total Operating Revenues	$261,182	($13,686)	$247,496
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	$67,603	($8,525)	$59,078
8	Power Production	41,680	(350)	41,330
9	Transmission	23,719	(6,298)	17,421
10	Distribution	6,946	0	6,946
11	Customer Accounting	3,921	0	3,921
12	Customer Service & Information	260	0	260
13	Sales, Econ Dvlp & Other	79	125	203
14	Administrative & General	17,675	(1,374)	16,301
15	Total Operating Expenses	$161,882	($16,422)	$145,460
16	Depreciation	$42,667	($38)	$42,629
17	Amortizations	$0	$3,061	$3,061
	Taxes:			
18	Property	$10,868	($27)	$10,841
19	Gross Earnings	0	0	0
20	Deferred Income Tax & ITC	(2,464)	124	(2,340)
21	Federal & State Income Tax	652	(153)	498
22	Payroll & Other	1,986	(0)	1,985
23	Total Taxes	$11,041	($57)	$10,985
24	Total Expenses	$215,591	($13,457)	$202,134
25	Allowance for Funds Used During Construction	$0	$0	$0
26	Total Operating Income	$45,591	($229)	$45,362

Northern States Power Company
Electric Utility - State of North Dakota

Case No. PU-20-____
Exhibit___(BCH-1) Schedule 11

OPERATING REVENUES, OPERATING EXPENSE,
TOTAL AVAILABLE FOR RETURN WITH PRESENT AND FINAL RATES
(000's)

Line No.	Description	Actual Year Ending 12/31/19 Present Rates	Final Increase	Actual Year Ending 12/31/19 Final Rates
		(A)	(B)	(C) = (B) + (A)
	Operating Revenues			
1	Retail	$198,147	($27)	$198,119
2	CIP Revenue Adjustment	$0		0
3	Interdepartmental	$0		0
4	Other Operating	$48,544		48,544
5	Gross Earnings Tax	$0		0
6	Total Operating Revenues	$246,691	($27)	$246,665
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	$64,623		$64,623
8	Power Production	$42,007		42,007
9	Transmission	$17,879		17,879
10	Distribution	$6,528		6,528
11	Customer Accounting	$3,379		3,379
12	Customer Service & Information	$425		425
13	Sales, Econ Dvlp & Other	$3		3
14	Administrative & General	$15,129		15,129
15	Total Operating Expenses	$149,973	$0	$149,973
16	Depreciation	$39,260		$39,260
17	Amortizations	($1,209)		(1,209)
	Taxes:			
18	Property	$11,084		$11,084
19	Gross Earnings	$0		0
20	Deferred Income Tax & ITC	$2,207		2,207
21	Federal & State Income Tax	$355	(7)	348
22	Payroll & Other	$2,019		2,019
23	Total Taxes	$15,665	($7)	$15,658
24	Total Expenses	$203,688	($7)	$203,682
25	AFUDC	$0	$0	$0
26	Total Operating Income	$43,003	($21)	$42,982

Statement of Operating Income
(000's)

Line No.	Description	2019 Actual Year Unadjusted	Adjustments	2019 Actual Year Adjusted
		(H)	(I)	(J)
	Operating Revenues			(Col F + G)
1	Retail	$199,332	($1,186)	$198,147
2	CIP Adjustment to Program Costs	0	0	0
3	Interdepartmental	0	0	0
4	Other Operating	64,154	(15,609)	48,544
5	Gross Earnings Tax	0	0	0
6	Total Operating Revenues	$263,486	($16,795)	$246,691
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	$71,607	($6,984)	$64,623
8	Power Production	42,400	(393)	42,007
9	Transmission	24,869	(6,990)	17,879
10	Distribution	6,528	0	6,528
11	Customer Accounting	3,379	0	3,379
12	Customer Service & Information	425	(0)	425
13	Sales, Econ Dvlp & Other	3	0	3
14	Administrative & General	16,927	(1,798)	15,129
15	Total Operating Expenses	$166,137	($16,164)	$149,973
16	Depreciation	$39,278	($18)	$39,260
17	Amortizations	$0	($1,209)	($1,209)
	Taxes:			
18	Property	$11,096	($12)	$11,084
19	Gross Earnings	0	0	0
20	Deferred Income Tax & ITC	698	1,509	2,207
21	Federal & State Income Tax	875	(520)	355
22	Payroll & Other	2,020	(1)	2,019
23	Total Taxes	$14,688	$977	$15,665
24	Total Expenses	$220,103	($16,415)	$203,688
25	Allowance for Funds Used During Construction	$0	$0	$0
26	Total Operating Income	$43,382	($380)	$43,003

Northern States Power Company

Cost Assignment and Allocation Manual

September 2020

Table of Contents

Section

I. INTRODUCTION

This Cost Assignment and Allocation Manual ("CAAM") was developed to specify the procedures that Northern States Power Company, a Minnesota corporation ("NSPM" or the "Company") follows in assigning and allocating costs among utility departments (electric and gas), among regulated services and non-regulated business activities and among jurisdictions.

NSPM was incorporated in 2000 under the laws of Minnesota and is a wholly owned operating utility subsidiary of Xcel Energy Inc. ("Xcel Energy" or the "Parent"). Xcel Energy was initially established as a registered holding company under the Public Utility Holding Company Act of 1935 ("PUHCA 1935"), with oversight by the Securities and Exchange Commission ("SEC"). On August 8, 2005, the Energy Policy Act of 2005 was signed into law. This repealed PUHCA 1935 and enacted the Public Utility Holding Company Act of 2005 ("PUHCA 2005"), which became effective on February 8, 2006. Responsibility for oversight of public utility holding companies was transferred from the SEC to the Federal Energy Regulatory Commission ("FERC") as a result of the Energy Policy Act of 2005.

NSPM conducts business in Minnesota, North Dakota, and South Dakota and has electric operations in all three states including the generation, purchase, transmission, distribution, and sale of electricity. NSPM also purchases, transports, distributes, and sells natural gas to retail customers and transports customer-owned natural gas in Minnesota and North Dakota.

NSPM owns the following direct subsidiaries: United Power and Land Company, which holds real estate; and NSP Nuclear Corporation.

As a member of a holding company system, NSPM receives administrative, management, environmental, and other support services from Xcel Energy Services Inc. ("XES" or the "Service Company"), a centralized service company. The Service Company provides services to Xcel Energy and its subsidiaries, at cost, pursuant to service agreements. The service agreement between NSPM and XES, including all amendments to the original Service Agreement, have been submitted to, and approved by, the Minnesota Public Utilities Commission ("Commission"). The cost allocation methodologies under which XES costs are assigned and allocated are set forth in that Commission approved service agreement, and while those allocation methodologies are not the subject of this NSPM CAAM, they are referenced in several sections herein.

The Service Company is referenced in the CAAM for the following reasons:

- The Service Company is listed as an affiliate company in the Transaction with Affiliates section for the services it provides to NSPM.
- The Service Company and all other companies in the Xcel Energy holding company system of companies are included in the Corporate Organization section to provide a listing of all affiliates of NSPM.
- The Service Company is referenced in the Cost Assignment and Allocation Process section because this section covers processes that may cross multiple legal entities.

The NSPM CAAM contains the following sections:

- Introduction (Section I)
- Corporate Organization (Section II)
- Description of Services (Section III)
- Transactions with Affiliates (Section IV)
- Cost Assignment and Allocation Process (Section V)
- Utility Allocations (Section VI)
- Non-regulated Business Activity Allocations (Sections VII)
- Jurisdictional Allocations (Section VIII)

DEFINITIONS

Abbreviations or Acronyms

The following abbreviations or acronyms are used within the CAAM document:

A&G	Administrative and general
AFUDC	Allowance for funds used during construction
ACC	Allocating cost center
CAAM	Cost Assignment and Allocation Manual
CIP	Conservation improvement program
Commission	Minnesota Public Utilities Commission
FERC	Federal Energy Regulatory Commission
FICA	Federal Insurance Contributions Act
FUTA	Federal Unemployment Tax Act
GAAP	Generally Accepted Accounting Principals
HR	Human Resources
IT	Information Technology
NSPM or the Company	Norther States Power Company, a Minnesota corporation
NSPW	Northern States Power Company, a Wisconsin corporation
NSP System	The electric production and transmission system of NSPM and NSPW operated on an integrated basis and managed by NSPM
O&M	Operating and maintenance
PSCo	Public Service Company of Colorado, a Colorado corporation
PUCHA 1935	Public Utility Holding Company Act of 1935
PUCHA 2005	Public Utility Holding Company Act of 2005
RTU	Remote terminal unit
SAP	SAP general ledger and work and asset management system
SCADA	Supervisory control and data acquisition
SEC	Securities and Exchange Commission
SKF	Statistical key figure
SPS	Southwestern Public Service Company, a New Mexico corporation
SUTA	State Unemployment Tax Authority
Utility subsidiaries or operating companies	NSPM, NSPW, PSCo, and SPS
UMP	Utility money pool
Xcel Energy or the Parent	Xcel Energy Inc. and its subsidiaries
XES or the Service Company	Xcel Energy Services Inc.

Terms

The following terms are used within the CAAM document:

Accounts Payable – the payment and reporting department of XES.

A&G – includes activity in FERC accounts 920-935, Administrative and General Expenses.

ACC – an organizational unit that collects cost to be allocated using the allocation ratios or factors included in the SKF.

Assessment – the process used by the accounting system to allocate costs from an ACC to the receiving cost element.

Cost Element – an organizational unit to SAP that is used to track costs in the accounting system as they move through the various processing steps.

Customer Accounting Costs – includes activity in FERC accounts 901-903, Customer Accounts Expenses; FERC accounts 906-910, Customer Service and Informational Expenses; and FERC accounts 911-917, Sales Expenses.

Final Cost Center – final cost center defined by business function, company code, and profit center.

Home Cost Center – captures only labor and payroll postings and maps to HR departments.

Internal Order – internal orders are accounting mechanisms used to track expenses associated with certain projects or functions.

Non-Operations and Maintenance Allocations – allocations designed to apportion expenses recorded in accounts other than O&M to electric, gas, thermal and nonutility. The non-O&M costs apportioned include depreciation, payroll taxes, miscellaneous service revenues, amortization expenses, etc.

O&M – includes activity in FERC accounts 500-935 with the exception of the following FERC accounts: 501, Fuel; 901-903, Customer Accounts Expenses; 906-910, Customer Service and Informational Expenses; 911-917, Sales Expenses; and 920-935, Administrative and General Expenses.

Profit Center – SAP data element that identifies the jurisdiction or joint venture owner of revenues and expenses.

Receiving Cost Element – a cost element that receives costs when a settlement or assessment process is run.

Segment – represents electric, gas, thermal, joint venture, or other and is derived by SAP from profit center and cost center.

SKF – the method by which the allocation ratios and factors are organized in the accounting system and linked to ACCs to facilitate the performance of the assessment process to allocate charges.

Supply Chain – the supply chain department of XES.

Work Breakdown Structure – structure used to group all aspects or phases of a given project or organizational group and render them easily reportable.

II. CORPORATE ORGANIZATION

OVERVIEW OF COMPANY SYSTEM

Xcel Energy Inc., a Minnesota corporation, is a registered holding company. Xcel Energy directly owns the utility subsidiaries that serve electric, natural gas, thermal, and propane customers in eight mid-western and western states including portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. These four utility subsidiaries are Northern States Power Company, a Minnesota corporation ("NSPM"); Northern States Power Company, a Wisconsin corporation ("NSPW"); Public Service Company of Colorado, a Colorado corporation ("PSCo"); and Southwestern Public Service Company, a New Mexico corporation ("SPS"). Along with the utility subsidiaries, the transmission-only subsidiaries, Xcel Energy Southwest Transmission Company, LLC ("XEST"), Xcel Energy Transmission Development Company, LLC ("XETD"), and Xcel Energy West Transmission Company, LLC ("XEWT"); WYCO Development LLC ("WYCO"), a joint venture with CIG to develop and lease natural gas pipelines, storage, and compression facilities; WestGas InterState, Inc. ("WGI"), an interstate natural gas pipeline company comprise the regulated utility operations. Xcel Energy's significant non-regulated subsidiaries are Eloigne Company; Capital Services, LLC; and Nicollet Holdings Company, LLC.

Xcel Energy owns the following additional direct subsidiaries, some of which are intermediate holding companies with additional subsidiaries: Xcel Energy Wholesale Group Inc., Xcel Energy Markets Holdings Inc., Xcel Energy International Inc., Xcel Energy Ventures Inc., Xcel Energy Retail Holdings Inc., Xcel Energy Communications Group Inc., , Xcel Energy WYCO Inc., Xcel Energy Transmission Holding Company, LLC, Xcel Energy Venture Holdings, Inc., Nicollet Holdings Company, LLC, and Xcel Energy Services Inc. Xcel Energy and its subsidiaries collectively are referred to as Xcel Energy Inc., and many do business under the Xcel Energy name. See the following pages for a complete legal entity organizational listing for Xcel Energy Inc. and its subsidiaries.

LIST OF REGULATED & NON-REGULATED AFFILIATES (as of June 30, 2019)

- **Xcel Energy Inc.**
  - Northern States Power Company, a Minnesota corporation
    - NSP Nuclear Corporation
    - Private Fuel Storage LLC
    - United Power and Land Company
  - Northern States Power Company, a Wisconsin corporation
    - Chippewa and Flambeau Improvement Company
    - Clearwater Investments, Inc.
      - Shoe Factory Holding LLC
    - NSP Lands, Inc.
  - Public Service Company of Colorado, a Colorado corporation**
    - 1480 Welton, Inc.
    - Beeman Irrigating Ditch and Milling Company
    - Consolidated Extension Canal Company

East Boulder Ditch Company
Fisher Ditch Company
Gardeners Mutual Ditch Company
Green and Clear Lakes Company
Hillcrest Ditch and Reservoir Company
Las Animas Consolidated Canal Company
P.S.R. Investments, Inc.
United Water Company
Southwestern Public Service Company, a New Mexico corporation
Nicollet Holdings Company, LLC
Capital Services, LLC
Nicollet Project Holdings, LLC
Nicollet Projects I, LLC
Betcher CSG LLC
Foreman's Hill CSG LLC
Grimm CSG LLC
Heyer CSG LLC
Huneke CSG LLC
Johnson I CSG LLC
Johnson II CSG LLC
Krause CSG LLC
RJC I CSG LLC
RJC II CSG LLC
Scandia CSG LLC
School Sisters CSG LLC
Webster CSG LLC
Nicollet Projects II, LLC
WestGas InterState, Inc.
Xcel Energy Foundation
Xcel Energy Communications Group Inc.
Seren Innovations, Inc.
Xcel Energy International Inc.*
Xcel Energy Markets Holdings Inc.
e prime, inc.*
Young Gas Storage Company Ltd.
Xcel Energy Retail Holdings Inc.
Xcel Energy Performance Contracting Inc.
Reddy Kilowatt Corporation
Xcel Energy Services Inc.
Xcel Energy Transmission Holding Company, LLC
Xcel Energy Southwest Transmission Company, LLC
Xcel Energy Transmission Development Company, LLC
Xcel Energy Acorn Transmission, LLC
Xcel Energy Birch Transmission, LLC
Xcel Energy West Transmission Company, LLC
Xcel Energy Venture Holdings, Inc.
Energy Impact Fund Investment LLC
Xcel Energy Investments, LLC

- Xcel Energy Ventures Inc.
  - Eloigne Company
    - Bemidji Townhouse LP
    - Chaska Brickstone LP
    - Crown Ridge Apartments LP
    - Cottage Court LP
    - Dakotah Pioneer LP
    - Edenvale Family Housing LP
    - Fairview Ridge LP
    - Farmington Family Housing LP
    - Farmington Townhome LP
    - Hearthstone Village LP
    - J&D 14-93 LP
    - Lauring Green LP
    - Links Lane LP
    - Lyndale Avenue Townhomes LP
    - Mahtomedi Woodland LP
    - Mankato Townhomes LLP
    - Marvin Garden LP
    - Moorhead Townhomes LP
    - Park Rapids Townhomes LP
    - Rochester Townhome LP
    - Rushford Housing LP
    - Safe Haven Homes, LLC
    - Shade Tree Apartments LP
    - Shakopee Boulder Ridge LP
    - Shenandoah Woods LP
    - Sioux Falls Partners LP
    - St. Cloud Housing LP
    - Tower Terrace LP
- Xcel Energy Wholesale Group Inc.*
  - Quixx Corporation*
    - Quixx Carolina, Inc.*
    - Quixxlin Corp.*
- Xcel Energy WYCO Inc.
  - WYCO Development, LLC

* Company is being classified in discontinued operations.
** Minority-ownership ditch and water companies have been excluded.

III. DESCRIPTION OF SERVICES

OVERVIEW

This section provides a description of NSPM's regulated services and non-regulated business activities. Each description identifies the types of costs associated with the service or business activity, and identifies the business area or department which offers the service.

REGULATED SERVICES

ELECTRIC UTILITY

Electric – Residential

Residential electric service represents the provision of electric service to residential customers within the NSPM service territory. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric – Commercial and Industrial

Commercial and industrial electric service represents the provision of electric service to commercial and industrial customers within the NSPM service territory. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric – Street Lighting

Street lighting electric service represents the provision of electric service to public authorities for lighting streets, highways, parks and other public places, or for traffic or other signal system service through Company-owned or customer-owned lighting equipment. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric – Other Sales to Public Authorities

Other sales to public authorities' electric service represent the provision of electric service to public authorities under special agreements or contracts. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric - Resale

Resale electric service represents the provision of electric service to NSPM wholesale customers or public authorities for resale to end-user customers or to power marketers. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, or through facilities owned by third parties, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric - Interdepartmental

Interdepartmental electric service represents the provision of electric service to NSPM company facilities at tariff rates. Costs associated with providing this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Off-System Electric Sales

NSPM sells electricity not required to serve its native load to off-system customers. Costs related to this activity can include fuel and purchased power costs. The revenues associated with these sales reside in FERC account 447, Sales for Resale-Electric. The costs related to this activity reside in FERC accounts 501, Fuel-Steam Generation; 555, Purchased Power; and 565, Transmission of Electricity by Others. In addition, the Company may allocate production O&M and transmission costs based on a percentage of overall sales relative to the type of off-system sales. These costs reside within the NSPM Electric Utility.

OTHER ELECTRIC OPERATING REVENUE

Rent from Electric Property

Rent from electric property results from the leasing of NSPM owned utility property not currently utilized for the provision of regulated services to non-affiliated third parties. Costs related to this service are primarily A&G costs associated with customer billings, as well as rental contract renewals. The revenue associated with the rentals resides in FERC account 454, Rent from Electric Property.

Interchange Agreement

The electric production and transmission costs of the entire NSP System are shared by NSP-Minnesota and NSP-Wisconsin. A FERC-approved Interchange Agreement between the two companies provides for the sharing of all generation and transmission costs of the NSP System based upon demand and energy ratios reflecting usage by the respective companies. The costs associated with this agreement reside in FERC account 557, Other Power Supply Expenses; and FERC 565, Transmission of Electricity by Others. The revenues reside in FERC account 456.1, Revenue from Transmission of Electricity of Others.

Joint Operating Agreement

The Joint Operating Agreement is a margin sharing agreement associated with proprietary energy trading activities. Revenues are recorded in FERC 456, Other Electric Revenues.

Miscellaneous Electric Revenue

In addition to the services detailed above, there are various activities that cannot be accounted for elsewhere, such as utility locating services, scrap metal sales, WindSource, customer connections, and refuse derived fuel incentive. These revenues are recorded in FERC account 456, Other Electric Revenues.

GAS UTILITY

Gas - Residential

Residential gas service represents the provision of natural gas service to residential customers within the NSPM service territory. Costs associated with this service relate to the purchase and delivery of gas through Company-owned facilities, primarily purchased gas, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Commercial and Industrial

Commercial and industrial gas service represents the provision of natural gas service to commercial and industrial customers within the NSPM service territory. Costs associated with this service relate to the purchase and delivery of gas through Company-owned facilities, primarily purchased gas, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Gas Utility. The table below shows the various rate classes within commercial and industrial gas services.

Rate Class	Maximum Requirements – Daily Therms	Maximum Requirements – Annual Therms
Small commercial	Less than 500	Less than 6,000
Large commercial	Less than 500	Greater than 6,000
Small demand billed commercial*	Less than 500	
Large demand billed commercial*	Greater than 500	

* Upstream demand costs are billed based on the highest one-day usage in the customer's history.

Gas – Interruptible

Interruptible gas service represents the provision of natural gas service to interruptible customers within the NSPM service territory. Interruptible service is subject to curtailment when either additional upstream pipeline or local distribution capacity is needed to ensure service to firm customers. Costs associated with this service relate to the purchase and delivery of gas through Company-owned facilities, primarily purchased gas, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Gas Utility. The table below shows the various rate classes within interruptible gas service.

Rate Class	Maximum Requirements – Daily Therms
Small interruptible	Less than 2,000
Medium interruptible	Greater than 2,000 and less than 50,000
Large interruptible	Greater than 50,000

Gas – Large Firm Transportation

Large firm gas transportation service represents the provision of gas delivery service on behalf of end-use customers, third-party suppliers or marketers whereby NSPM transports gas owned by others over NSPM's gas pipeline system. Costs associated with this service primarily include the facilities O&M and depreciation costs and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Interruptible Transportation

Interruptible gas transportation service represents the provision of gas delivery service on behalf of end-use customers, third-party suppliers or marketers whereby NSPM transports gas owned by others over NSPM's gas pipeline system. Interruptible transportation gas service is subject to curtailment when either additional upstream pipeline or the local distribution capacity is needed to ensure service to firm customers. Costs associated with this service primarily include the facilities O&M and depreciation costs and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Negotiated Transportation

Negotiated firm and interruptible gas transportation service (bypass customers) represents the provision of gas delivery service on behalf of end-use customers, third-party suppliers or marketers whereby NSPM transports gas owned by others over NSPM's gas pipeline system. Interruptible transportation gas service is subject to curtailment when either additional upstream pipeline or the local distribution capacity is needed to ensure service to firm customers. Costs associated with this service primarily include the facilities O&M and depreciation costs and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Interdepartmental

Interdepartmental gas service represents the provision of natural gas service or gas transportation service to NSPM company facilities at tariff rates. Costs associated with providing this service relate to the purchase and delivery of gas through NSPM owned facilities, primarily purchased gas, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Limited Firm

Standby gas service represents on-system back-up propane service for interruptible service customers. Costs associated with this service primarily include propane purchases and the facilities O&M. These costs reside within the NSPM Gas Utility.

Gas – Daily Balancing Service

Daily balancing gas service represents a service to transportation customers that allows them to remedy deviations between nominated and delivered gas and gas consumed by the transportation customer. Costs associated with this service primarily include upstream pipeline costs. These costs reside within the NSPM Gas Utility.

OTHER GAS REVENUE

Miscellaneous Gas Revenue

Various services are provided that cannot be accounted for elsewhere such as propane transportation charges and bundled sales. These revenues are recorded in FERC account 495, Other Gas Revenues.

COMMON ELECTRIC AND GAS REVENUE

Late Payments Fees/Miscellaneous Service Revenues

Revenues from the additional charges imposed because of customers failure to pay their bill by specified due date are recorded into FERC account 450, Electric Forfeited Discounts; and FERC account 487, Gas Forfeited Discounts. Miscellaneous customer related revenue, such as service connections and returned check charges, are recorded in FERC account 451, Miscellaneous Electric Service Revenue; and FERC account 488, Miscellaneous Gas Service Revenues.

CIP Incentives

The CIP Incentive is a mechanism established by an April 7, 2000 Order of the Commission that provides utilities with an incentive to increase cost-effective utility investment in conservation improvement programs beyond the spending levels required by Minnesota Statute. The revenues associated with the CIP incentives are identified by unique accounts and are recorded in FERC account 456, Other Electric Revenues; and FERC 495, Other Gas Revenues. An adjustment is made to remove these revenues from our cost of service study and they do not impact our revenue requirements.

ConnectSmart

NSPM provides a service for customers moving into or across the region to set up utility service and other subscription services to their homes (e.g., newspaper, local and long-distance telephone, cable TV, etc.). NSPM, through its call center, receives telephone requests for this service, and sends these requests, for a fee, to AllConnect (a third-party contractor) for the coordination of installation of services. Costs related to this activity include direct charges for labor, materials and outside services associated with the service provided. In addition, payroll taxes, lost time, facilities, workers' compensation, incentive, pension, and benefit costs are allocated based on labor dollars, and labor-related overhead and a corporate residual overhead are applied to nonregulated business activities. The revenues and costs associated with this service are identified by unique accounts, and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations. For rate making purposes, in the event this service experiences revenues in excess of direct expenses, an adjustment is made to credit the net impact in FERC 456, Other Electric Operating Revenues, to reflect the benefit of this service to the utility customers.

Hazardous Waste Disposal

NSPM has a Hazardous Waste consolidation facility at Chestnut Service Center in Minneapolis, Minnesota. The facility accepts and consolidates hazardous and specially-regulated waste materials from generating assets, service centers, substations, office buildings, and field operations projects in both NSPM and NSPW service territories. This facility ensures the wastes are properly characterized aggregated and consolidated at approved, permanent and appropriately licensed waste disposal facilities. This facility is also the central collection point for any PCB contaminated electrical equipment.

NON-REGULATED BUSINESS ACTIVITIES

The following business activities have been approved by the Commission as non-regulated business activities. Detailed descriptions of each of the non-regulated business activities are provided in this section.

HomeSmart

Xcel Energy HomeSmart offers resources for the repair, replacement and maintenance of major appliances and systems in customers' homes. This includes service plans to cover certain appliances, sewer and plumbing issues; heating, ventilating and air conditioning (HVAC) systems; replacement assistance coverage; and preventive maintenance. HomeSmart also sells and installs HVAC systems and water heaters. Costs related to these activities include direct charges for labor, equipment, materials, and outside services associated with the services provided. In addition, payroll taxes, lost time, and pension and benefit costs are allocated based on labor dollars, and a labor related overhead and a corporate residual overhead are applied to non-regulated business activities. (Please refer to Section VII of the CAAM for more information.) The revenues and costs associated with HomeSmart are identified by unique accounts and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations.

Customer Owned Street Lighting Maintenance

NSPM supplies maintenance services for communities that own their own street light systems. Maintenance service for customer owned street light systems is limited to the fixture service only; and ranges from full fixture service to partial fixture service where the customer provides the material necessary to repair the street light. The customer is responsible for all other repairs and replacements under the "Non-regulated Customer Owned Street Maintenance" service. Costs related to this activity include labor and materials associated with the service provided. In addition, payroll taxes, lost time, and pension and benefit costs are allocated based on labor dollars, and a labor related overhead and a corporate residual overhead are applied to non-regulated business activities. The revenues and costs associated with this service are identified by unique accounts and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations. See Docket E-002/M-92-614 for the Commission order to treat this service as non-regulated.

Sherco Steam Sales to Liberty Paper Inc.

NSPM supplies steam from the Sherburne County Generating Station to Liberty Paper, Inc. ("LPI") in order to meet LPI's thermal energy needs. Costs related to this activity include labor and materials associated with the service provided. In addition, payroll taxes, lost time, and pension and benefit costs are allocated based on labor dollars, and a labor-related overhead is applied to nonregulated business activities. The revenues and costs associated with this service are identified by unique accounts, and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations which are excluded for ratemaking purposes. See Docket E002/M-93-1253 for the Commission order to treat this service as non-regulated. In addition to steam services, LPI takes electric and natural gas services from NSPM which are tariffed services provided at tariffed rates.

InfoWise GX Meter

InfoWise GX Meter is an energy management reporting solution with customized data for businesses to help manage and control their energy use. This product consists of unique interactive reports with detailed information, including both consumption and demand levels, to help the customer pinpoint and analyze their facility's energy use. By analyzing past energy use, this product can help drive company green strategies while helping customize a strategic business plan for facility managers, as well as deliver a bill estimator tool that keeps track of budgets and identifies cost saving opportunities. Costs related to this activity include direct charges for labor, materials and outside services associated with the service provided. In addition, payroll taxes, lost time, facilities, workers' compensation, incentive and pension and benefits are allocated based on labor dollars, and a labor-related overhead and a corporate residual overhead are applied to nonregulated business activities. The revenues and costs associated with this service are identified by unique SAP Cost Centers, and are recorded in FERC accounts 417, Revenues from Nonutility Operations, and 417.1, Expenses from Non-utility Operations.

IV. TRANSACTIONS WITH AFFILIATES

OVERVIEW

NSPM directly incurs and pays for the majority of its costs, there are, however, services provided to NSPM by other affiliates within the Xcel Energy system of companies. In addition, NSPM provides a limited amount of operations, maintenance, and management advisory services to its affiliates. NSPM has numerous Affiliated Interest Agreements that have been approved by the Commission.

The sections below separately detail the nature and terms of transactions for services and asset transfers provided by NSPM to its affiliates, as well as services and asset transfers provided to NSPM by each of its affiliates. This section includes descriptions of affiliate transactions only and does not include convenience payments.

The cost allocation methodologies under which the Service Company costs are assigned and allocated are set forth in the service agreement, and while they are not the subject of this NSPM CAAM, they are included in this section to provide as complete a picture as possible of all affiliate transactions. The NSPM Service Agreement is reviewed and filed annually with the Commission. The last filing was approved in Docket E,G002/AI-19-371 on July 10, 2019. NSPM's affiliate transactions consist primarily of transactions with the Service Company for administrative, management, accounting, legal, engineering, environmental, and other support services.

Terms of Transactions

Tariff Rate – the price charged to customers under applicable tariffs on file with federal or state regulatory commissions. Tariff rates are used for transactions with affiliates involving the provision of regulated services.

Fully Distributed Cost **–** the term fully distributed cost means that transactions billed include all direct and indirect costs, including overheads. Affiliate transactions billed by NSPM include labor related overheads and a working capital fee when appropriate. This method of assigning and allocating costs to these affiliate transactions ensures that the payments to or by NSPM are reasonable and have not resulted in any ratepayer subsidization. In the table below, fully distributed cost may also refer to a price established in a separate Affiliated Interest Agreement.

NSPM applies a labor related overhead to services provided by NSPM to affiliates and also applies a working capital fee on services NSPM provides to non-NSPM company affiliates. Both the labor related overhead and the working capital fees are discussed in Section VII.

The remainder of this section is detailed by affiliate. Affiliates may be listed under the "Services Provided by NSPM to Affiliates" section and/or the "Services Provided by Affiliates to NSPM" section. The details relating to the nature, frequency, and terms of the affiliate transactions are itemized for NSPM and each affiliate.

SERVICES PROVIDED BY NSPM TO AFFILIATES

Nature of Transactions	Terms
NSPW	
O&M – production, decommissioning, and transmission costs associated with the Interchange Agreement (FERC Docket No. ER15-1575-000).	Fully distributed cost
SCADA and Gas Dispatch – sharing of SCADA costs in accordance with Docket G-002/AI-94-831.	Fully distributed cost
Materials and Supplies – materials and supplies, including any associated freight, purchase loadings, and warehouse loadings.	Fully distributed cost
Miscellaneous – miscellaneous other charges, including labor, associated loadings, and lease costs.	Fully distributed cost
PSCo	
Materials and Supplies – materials and supplies, including any associated freight, purchase loadings, and warehouse loadings.	Fully distributed cost
Joint Operating Agreement – margin sharing associated with proprietary energy trading activities.	Fully distributed cost
Miscellaneous – miscellaneous other charges, including labor, associated loadings, and lease costs.	Fully distributed cost
SPS	
Materials and Supplies – materials and supplies, and any associated freight, purchase loadings, and warehouse loadings.	Fully distributed cost
Joint Operating Agreement – margin sharing associated with proprietary energy trading activities.	Fully distributed cost
Miscellaneous – miscellaneous other charges, including labor and associated loadings and lease costs.	Fully distributed cost

Xcel Energy Inc.

Nature of Transactions	Terms
Miscellaneous - miscellaneous other charges, including 401(k) match and a dividend on common stock.	Fully distributed cost

SERVICES PROVIDED BY AFFILIATES TO NSPM

Nature of Transactions	*Terms*
Xcel Energy Services Inc.	
*Executive Management Services** – represents charges for executive management services, including, but not limited to, officers of Xcel Energy.	Fully distributed cost
*Investor Relations** – provides communications to investors and the financial community. Coordinates the transfer agent and shareholder record keeping functions and plans the annual shareholder meeting.	Fully distributed cost
*Internal Audit & Risk** – reviews internal controls and procedures to ensure assets are safeguarded and transactions are properly authorized and recorded. Evaluates contract risks and trading risks.	Fully distributed cost
*Legal** – provides legal services related to labor and employment law, litigation, contracts, rates and regulation, environmental matters, real estate, and other legal matters.	Fully distributed cost
*Claims Services** – provides claims services related to casualty, public, and company claims.	Fully distributed cost
*Corporate Communications** – provides corporate communications, speech writing, and coordinates media services. Provides advertising and branding development for the companies within the Xcel Energy system. Manages and tracks all charitable contributions made on behalf of the Xcel Energy system.	Fully distributed cost
*Employee Communications** – develops and distributes communications to employees.	Fully distributed cost
*Corporate Strategy & Business Development** – facilitates development of corporate strategy and prepares strategic plans, monitors corporate performance, and evaluates	Fully distributed cost

business opportunities. Develops and facilitates process improvements.	
*Government Affairs** – monitors, reviews and researches government legislation.	Fully distributed cost
*Facilities & Real Estate** – operates and maintains office buildings and service centers. Procures real estate and administers real estate leases. Administers contracts to provide security, housekeeping and maintenance services for such facilities. Procures office furniture and equipment.	Fully distributed cost
*Facilities Administrative Services** – includes but is not limited to the functions of mail delivery, duplicating, and records management.	Fully distributed cost
*Supply Chain**– includes contract negotiations, development and management of supplier relationships and acquisition of goods and services. Also includes inventory planning and forecasting, ordering, accounting, and database management. Warehousing services includes receiving, storing, issuing, shipping, returns, and distribution of material and parts.	Fully distributed cost
*Supply Chain Special Programs** – develops and implements special programs utilized across Xcel Energy such as procurement cards, travel services, and compliance with corporate MWBE (minority women business expenditures) program goals.	Fully distributed cost
*Human Resources** – establishes and administers policies related to employment, compensation, and benefits. Maintains HR computer system, the tuition reimbursement plan, and diversity program. Coordinates the bargaining strategy and labor agreements with union employees. Provides technical and professional development training and general HR support services.	Fully distributed cost
*Finance & Treasury** – coordinates activities related to securities issuances, including maintaining relationships with financial institutions, cash management, investing activities, and monitoring the capital markets. Performs financial and economic analysis.	Fully distributed cost
*Accounting, Financial Reporting & Taxes** – maintains financial books and records. Prepares financial and statistical reports, tax filings, and ensures compliance with the applicable laws and regulations. Maintains the	Fully distributed cost

accounting systems. Coordinates the budgeting process.	
*Payment & Reporting** – processes payments to vendors and prepares statistical reports.	Fully distributed cost
*Receipts Processing** – processes payments received from customers of the operating companies and affiliates.	Fully distributed cost
*Payroll** – processes payroll including but not limited to time reporting, calculation of salaries and wages, payroll tax reporting, and compliance reports.	Fully distributed cost
*Rates & Regulation** – determines the operating companies' regulatory strategy, revenue requirements, and rates for retail and wholesale customers. Coordinates the regulatory compliance requirements and maintains relationships with the regulatory bodies.	Fully distributed cost
*Energy Supply Engineering and Environmental** – provides engineering services to the generation business. Establishes policies and procedures for compliance with environmental laws and regulations. Researches emerging environmental issues and monitors compliance with environmental requirements. Oversees environmental cleanup projects.	Fully distributed cost
*Energy Supply Business Resources** – provides performance, specialists, and analytical services to the operating companies generation facilities.	Fully distributed cost
*Energy Markets Regulated Trading & Marketing** – provides electric trading services to the operating companies electric generation systems including load management, system optimization, and resource acquisition.	Fully distributed cost
*Energy Markets-Fuel Procurement** – purchases fuel for operating companies electric generation systems (excluding nuclear).	Fully distributed cost
*Energy Delivery Marketing** – develops new business opportunities and markets the products and services for the Delivery business unit.	Fully distributed cost
*Energy Delivery Construction, Operations & Maintenance** – constructs, maintains, and operates electric and gas delivery systems.	Fully distributed cost
*Energy Delivery Engineering/Design** – provides engineering	Fully distributed cost

and design services in support of capacity planning, construction, operations, and materials standards.	
*Marketing & Sales** – provides marketing and sales services for the operating companies and affiliates for their electric and natural gas customers including strategic planning, segment identification, business analysis, sales planning, and customer service.	Fully distributed cost
*Customer Service** – provides service activities to retail and wholesale customers. These services include meter reading, customer billing, call center, and credit and collections.	Fully distributed cost
*Aviation Services** – provides aviation and travel services to employees.	Fully distributed cost
*Fleet** – oversees the Utility subsidiaries Fleet Services business unit.	Fully distributed cost
*Business Systems** – provides basic information technology services such as: application management, voice and data network operations and management, customer support services, problem management services, security administration, and systems management. In addition, Business Systems acts as a single point of contact for delivery of all information technology services to Xcel Energy. Business Systems partner with vendors to ensure the delivery of benchmarking, continuous improvement, and leadership around strategic initiatives and key developments in the marketplace.	Fully distributed cost

** Corporate Governance activities within this service function will be allocated using the average of the revenue ratio with intercompany dividends assigned to Xcel Energy Inc., full time equivalent hours including overtime, and the total assets ratio including Xcel Energy Inc.'s per book assets.*

V. COST ASSIGNMENT AND ALLOCATION PROCESS

OVERVIEW

This section of the CAAM provides an overview of the cost assignment and allocation principles of NSPM and the accounting processes within the monthly accounting close and within the general ledger, including both system generated processes and manual processes, used to assign and allocate costs between the regulated services and the non-regulated business activities of NSPM. Each major step of the accounting process is identified in the following paragraphs and will be explained in conjunction with the process flowchart of this section. Each major step results in costs being either directly assigned or allocated to regulated services and non-regulated business activities. The result of applying these principles is that each company, utility, jurisdiction and non-regulated business activity pays the full cost for any service provided to support their respective operations.

Many of the assignment and allocation processes occur in the Service Company or are administered by Service Company personnel. As noted in the Introduction, the Service Company provides services "at cost" to the Utility subsidiaries and affiliate companies.

The processes discussed in this section are integral to the financial books and records of NSPM and are included to provide a comprehensive picture.

COST ASSIGNMENT AND ALLOCATION PRINCIPLES

NSPM applies the following cost assignment and allocation principles. The cost assignment and allocation approach is a fully distributed costing method as approved by the Commission in NSPM's electric and gas rates cases (E002/GR-92-1185, G002/GR-92-1186 and G002/GR-97-1606) and the Commission September 28, 1994 Order in Docket G, E-999/CI-90-1008.

The hierarchical cost assignment and allocation principles are:

I. Tariffed rate shall be used to value tariffed services provided.
II. Costs shall be directly assigned to either regulated or non-regulated business activities whenever possible.
III. Costs that cannot be directly assigned to either regulated or non-regulated activities or jurisdictions will be described as common costs. Common costs shall be grouped into homogeneous cost categories designed to facilitate the proper allocation of costs between regulated and non-regulated activities or jurisdictions in accordance with the following principles:
    a. Cost causation. All activities or jurisdictions that cause the cost to be incurred shall be allocated a portion of that cost. Direct assignment of a cost is preferred to the extent that the cost can be traced to the specific activity or jurisdiction.
    b. Variability. If the fully distributed cost study indicates a direct correlation exists between a change and the incurrence of a cost and cost causation, that cost shall be allocated based upon that relationship.

c. Traceability. A cost may be allocated using a measure that has a logical or observable correlation to all the activities or jurisdictions that case the cost to be incurred.
d. Benefit. All activities or jurisdictions that benefit from a cost shall be allocated a portion of that cost.

IV. Residual. The residual of costs left after either direct or indirect assignment or allocation shall be allocated based upon an appropriate general allocator as defined in this CAAM.
V. Whenever neither direct or indirect measures of cost causation can be found, the cost category shall be allocated based upon a general allocator.

A significant portion of NSPM's costs are incurred directly by NSPM. These costs are directly assigned or allocated based on the above principles to utilities, jurisdictions, and to non-regulated business activities. Utility allocations are described in Section VII and jurisdictional allocations are described in Section IX.

ACCOUNTING PROCESSES

The flowchart in this section provides a high-level overview of the major steps in the monthly accounting close process and the systems used to generate the financial books and records of NSPM. Several steps within the process have allocations imbedded within and are included to provide as much information as possible to promote an understanding of where direct assignment or allocations can occur.

Feeder Systems (Addendum A, Flowchart Item 1)

The monthly close process initially starts with the collection of accounting information from feeder systems as identified in Item 1 on the flowchart. Feeder systems gather accounting transactions on a daily, weekly or monthly basis and 'feed,' or pass, those accounting transactions to the general ledger within SAP.

SAP General Ledger System Processing (Addendum A, Flowchart Item 2)

Journal entries to record monthly transactions such as interest accruals, amortizations, cash transactions, receivables setup, etc., are entered directly into SAP using the SAP journal entry input screens. These journal entries also include the journal entries to record overheads on non-regulated business activities (see Section VII).

Once all the transactions from the processes identified above are recorded in SAP, there are multiple processing steps within SAP, including settlements and assessments. These processes affect regulated services and non-regulated business activities and are detailed separately on the following pages.

Settlements and Assessments (Addendum A, Flowchart Item 3)

All costs identified as billable are processed using the settlement and/or assessment processes of the SAP system. These processes bill transactions from the legal entity that performed the service to the legal entity that received or is responsible for the service. This process captures:

- Service Company direct and allocated billings of all its costs to affiliated interests;
- Direct billings between a utility subsidiary and an affiliated interest other than the Service Company which are often referred to as intercompany charges or billings; and
- Direct billings between business areas within a legal entity.

For example, the settlements process will settle Service Company labor to the affiliated company if the labor is a direct charge or it will send the charges to an ACC if the charge is to be allocated. The assessment process will then clear the ACC by allocating the charges using an approved method of allocation to the legal entities to which the employee is providing services along with the appropriate labor and labor-related overheads. Transactions between affiliates (excluding XES) are direct charges, as are charges from one business area to another business area (for example, charges from the Distribution Operations business area to the Energy Supply business area). After the settlements and assessment processes are completed, all costs reside on the books of the legal entity ultimately responsible for the charge in the appropriate FERC account.

Business View (Addendum A Flowchart Item 4)

The business view of the SAP general ledger provides a GAAP view of the accounting transactions necessary to prepare SEC financial statements and other GAAP financial reports as well as the information necessary for the business areas to manage the business.

FERC Account Data Prior to Utility and Non-Regulated Allocations (Addendum A Flowchart Item 5)

At the same time that the business view is available, the pre-allocated FERC view of the SAP general ledger is available. The following utility allocations and non-regulated allocations are necessary for common costs to be allocated to the gas, electric, and non-regulated businesses.

Utility Allocations and Non-regulated Allocations (Addendum A, Flowchart Item 6)

NSPM's costs are directly assigned or allocated to electric, gas, or non-regulated business activities whenever possible. When charges can't be directly assigned, they are charged as common and then allocated to the electric and gas utilities using utility allocations. Common utility costs are grouped into two categories: (1) O&M utility allocations and (2) rate base and non-O&M utility allocations. These allocations are performed monthly within the SAP system and are described in Section VII.

In addition to the costs directly assigned to the non-regulated business activities from the Service Company and within NSPM, the non-regulated business activities are charged with a labor related overhead and an allocation of corporate costs. See Section VIII for additional information related to non-regulated business activities.

All costs that can be directly assigned or allocated to the electric or gas utility operations or to the non-regulated business activities are appropriately accounted for in the books and records of NSPM before jurisdictional allocations occur. A study is performed annually, and as required for rate case filing purposes, to identify all rate base and non-O&M costs that are common among the jurisdictions of NSPM (Minnesota, North Dakota, and South Dakota). These costs are then allocated among the jurisdictions according to the allocations described in Section IX.

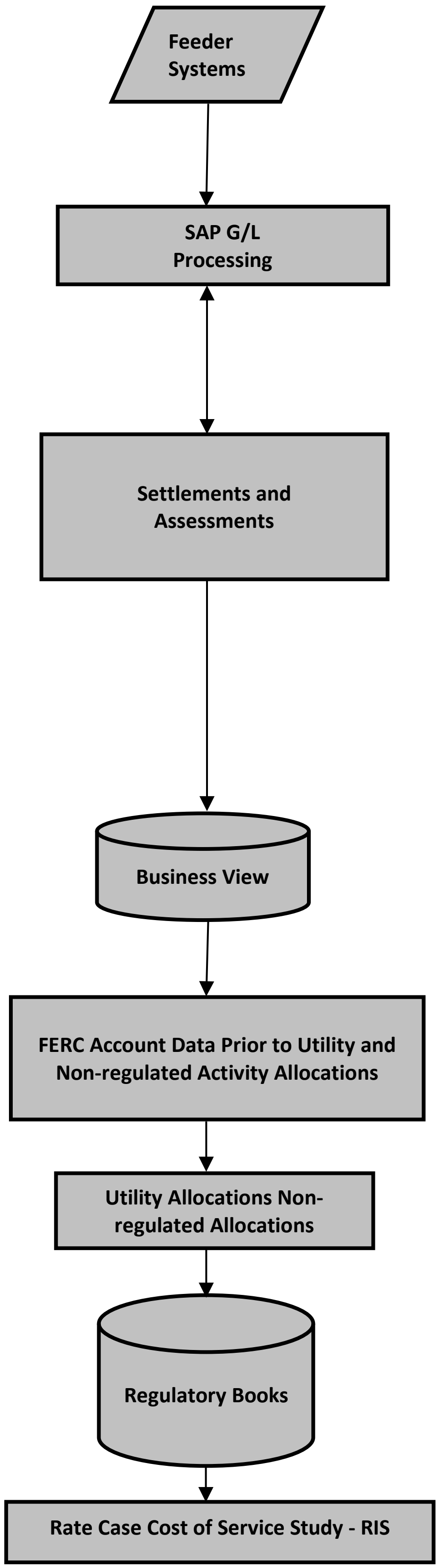
Regulatory Books and Records (Addendum A Flowchart Item 7)

After all the above processes are complete, the result is the FERC financial books and records of NSPM.

Rate Case Cost of Service Study (Addendum A Flowchart Item 8)

The FERC books and records are the starting point for the preparation of a cost of service study that will be used in a gas or electric rate case filing.

ADDENDUM A – PROCESS FLOWCHART



Item 1 – Feeder Systems
- **Labor Distribution**
- **Accounts Payable**
- **Money Pool**
- **Customer Billing**
- **Fixed Asset Ledger**

Item 2 – SAP general ledger system processing

Item 3 – Settlements and Assessments
- **Labor Overheads**
- **Aviation Distribution**
- **Stores/Warehouse Overheads**
- **Purchasing Overheads**
- **Fleet Distribution**
- **Information Technology**
- **Shared Asset Distribution**
- **Facilities Distribution**
- **Engineering & Supervision**
- **Capital A&G**

Item 4 – Business View

Item 5 – FERC account data prior to Utility and Non-regulated activity allocations

Item 6 – Utility Allocations and Non-regulated allocations

Item 7 – Regulated books and records

Item 8 – Rate case cost of service study - Rate Information System ("RIS")

Feeder and Overhead System Detail

LABOR DISTRIBUTION

Description:	Wages and salaries of employees engaged in work on behalf of regulated services and non-regulated activities are assigned or allocated based on positive time reporting through the labor distribution system. Positive time reporting requires each employee to report the hours worked for each day using one-tenth of an hour or greater increments, while providing for aggregation of time when appropriate. Under this method, employees' time is reported on the basis of accounting codes related to specific operating utility companies or affiliates and/or functional services.
Provider of Service:	Service Company Operating companies or affiliates
User of Service:	Operating companies or affiliates, including utility operations, jurisdictions, and non-regulated activities within an operating company.
Method of Allocation:	All bi-weekly and semi-monthly employees' labor expenses are recorded by company personnel on time sheets and entered into the time reporting system, which feeds into the labor distribution system. The employee submitting the time sheet is responsible for coding the internal order numbers to charge the appropriate operating companies or affiliates, business function (e.g., capital, operations, maintenance, clearing, purchasing and/or warehousing, etc.) and regulated or non-regulated operations. Time must be completed and submitted for review and approval by certain cut-off dates established by the Payroll Department. The employee's supervisor or manager is responsible for reviewing and approving all time entries and verifying that the employee is using the correct accounting. The labor distribution system used for bi-weekly employees includes the distribution of actual paid and accrued labor dollars/hours to the internal order number charged based on the hours worked. Accrual of payroll is to facilitate the recording of labor costs on a calendar month basis. This includes any reversal of the prior month's accrual. The charge of labor dollars for semi-monthly employees to internal order numbers is based on a distribution of the monthly salary of the employee.

LABOR OVERHEADS

Description:	Employee labor overhead costs are captured in the following categories:

Benefit employees:

- Non-productive labor costs (vacation, sick, holiday, etc.)
- Pension and Insurance (401k match, retirement related consulting, active healthcare, life and LTD insurance premiums, miscellaneous benefit programs and LTD benefits for former or inactive employees before retirement, as well as the service cost portion of qualified pension, non-qualified pension and retiree healthcare)
- Benefits Non-Service (non-service cost portion of qualified pension, non-qualified pension and retiree healthcare)
- Workers compensation (FAS 112 actuarial cost and insurance premiums)
- Incentives (Incentives are a labor overhead for Service Company, PSCo, and SPS. Incentives for NSPM and NSPW are charged directly to FERC accounts 920 and 517).
- Payroll taxes (FICA, FUTA, SUTA)
- Labor and expense of the Human Resource Service Center

Non-Benefit employees:

- Payroll taxes (FICA, FUTA, SUTA)
- Workers compensation

Provider of Service: Service Company
Operating companies or affiliates

User of Service: Operating companies or affiliates, including utility operations, jurisdictions, and non-regulated activities within an operating company.

Method of Allocation: Labor overheads are allocated within a legal entity by calculating a separate loading rate for each cost category identified in the "Description" section above.

For each legal entity and each category, the costs are allocated based on a single-factor formula that is comprised of total estimated costs for the category divided by total estimated productive labor costs.

Legal entity specific rates for each category are applied to productive labor charges as appropriate for each resource type. Labor loadings applied to labor charges follow the labor charges. For example, Service Company labor overheads follow Service Company labor and NSPM labor overheads follow NSPM labor.

AVIATION DISTRIBUTION

Description:	The Aviation Services department in the Service Company is responsible for managing and operating the two corporate leased aircraft used by the Xcel Energy. Costs include: pilot salaries including labor overheads, O&M costs, lease costs, and A&G costs associated with managing the Aviation Services department.
Provider of Service:	Service Company
User of Service:	Service Company, operating companies or affiliates, including utility operations, jurisdictions, and non-regulated activities within an operating company.
Method of Allocation:	Aviation costs are allocated using the average of the Revenue Ratio with intercompany dividends assigned to Xcel Energy Inc., Full Time Equivalent Hours Including Overtime, and the Total Assets Ratio including Xcel Energy Inc.'s per book assets. Any spousal use of the aircraft must be approved and is billed to Xcel Energy Inc.

STORES/WAREHOUSE OVERHEAD

Description:	Inventory warehousing costs, including labor, supervision, materials and supplies are allocated through pools to the business areas as an overhead on materials and supplies as materials and supplies are issued from/returned to a storeroom or warehouse.
Provider of Service:	Service Company Operating companies
User of Service:	Operating companies or affiliates, including utility operations, jurisdictions, and non-regulated activities within an operating company.
Method of Allocation:	The overhead costs for inventory items as noted above and associated adjustments are accumulated within the Supply Chain warehouse ACC's. These accumulated overhead costs are allocated to material issuances/returns from the storeroom. Costs are collected in ACC's on the Service Company and Operating Companies; then cleared using a warehouse overhead loading based on a costing sheet, cost element and AP document type criterion.

PURCHASING OVERHEAD

Description:	The Supply Chain organization in the Service Company has the responsibility for distributing the corporate purchasing and contract services costs to the functional area(s) of the operating companies or affiliates along with the cost of the materials and supplies ordered. Purchasing costs are made up of activities such as developing requisitions, contracts and purchase orders to procure materials and services and manage supplier relationships, negotiating complex procurement agreements/contracts for strategic supplier partnerships and service contracts, monitoring supplier performance, and managing purchase records, supplier qualification records, supplier diversity program, and support, maintenance, and performance monitoring of key applications and metrics used throughout the purchasing process.
Provider of Service:	Service Company Operating companies
User of Service:	Service Company, operating companies and affiliates, including utility operations, jurisdictions, and non-regulated business activities within an operating company.
Method of Allocation:	Costs are collected in ACC's on the Service Company and the operating companies and cleared using an overhead loading based on costing sheet, cost element, and AP document type criterion.

FLEET DISTRIBUTION

Description:	The Fleet Services department in the Service Company is responsible for managing the fleet assets owned by the operating companies. Fleet assets are vehicle units that are organized into fleet work centers, which group together vehicles similar in nature for a specific business function within an Operating Company. . The SAP Work Manager records the utilization of our fleet assets and allocates the cost to the business areas of operating companies and affiliates for the costs of using vehicles or associated equipment using fleet activity rates based on work centers. Fleet costs included in the calculation of the monthly billing rate include: licensing taxes and fees, lease costs, material and labor costs for maintenance and repair, fuel, labor loadings, and overhead for overall management of the Fleet Services department that includes labor, facilities, insurance, utilities, computers, phones, and office supplies.
Provider of Service:	Service Company Operating companies
User of Service:	Service Company, operating companies or affiliates, including utility operations, jurisdictions and non-regulated business activities within an operating company.
Method of Allocation:	Costs are collected in ACC's on the Service Company and operating companies which are cleared using an overhead fleet rate based on the weighted vehicle type to the respective business area.

INFORMATION TECHNOLOGY

Description:	The Business Systems organization in the Service Company is responsible for managing the corporate IT assets and services of Xcel Energy. Business Systems bills out O&M and capital costs related to Xcel Energy's corporate IT equipment and services incurred internally, as well as costs incurred through third party vendors. Costs include system O&M, desktop services, phone service, servers, infrastructure costs, software, software licensing, system design and implementation, labor and labor overheads, etc.
Provider of Service:	Service Company
User of Service:	Service Company, operating companies, or affiliates, including utility operations, jurisdictions and non-regulated activities within an operating company.
Method of Allocation:	IT costs are charged through several different methods. Costs are charged directly to the operating companies, affiliates, jurisdictions or non-regulated activities on the invoice, timesheet, expense report or other source document to the company(ies) benefiting from the service whenever possible. If costs cannot be charged directly to an operating company, affiliate, jurisdiction or non-regulated activity, the costs are charged to the appropriate Service Company indirect ACC that will assign the costs using a cost causative method to the companies benefiting from the system, application, or service. For costs that can be identified as benefiting a particular service function, those services would be charged to a Service Company indirect ACC using the approved allocation factor for that business area. If an indirect ACC cannot be identified that would assign costs in a cost causative method, a new indirect ACC will be created. However, if the project will be in-serviced within one year and if O&M costs will be less than $250,000 in total for the project, an internal order will be used to assign costs using a cost causative method to the companies benefiting from the system, application, or service.

ACCOUNTS PAYABLE

Description:	The Payment and Reporting Department (Accounts Payable), in the Service Company, processes several types of documents for payment on behalf of the operating companies and affiliates. Accounts Payable uses SAP to process invoice payments associated with purchase orders, contracts, requests for payment (non-purchase orders, non-contract invoices) and employee payments, including per diem charges, suggestion system award payments and employee expense reimbursements. The charges for goods, materials and services, which post directly to the general ledger of each operating company and affiliate, differ for each type of document.
Provider of Service:	Service Company
User of Service:	Service Company, operating companies and affiliates, including utility operations, jurisdictions, and non-regulated activities within an operating company.
Method of Allocation:	Within each operating company and affiliate, charges are directly assigned whenever possible. Charges may be distributed to multiple business functions or business areas based on the accounting code(s) on each document. If necessary, costs may be allocated using any surrogate measure that has a logical or observable correlation to the charges in the quantities sold, the services that caused the cost to be incurred or that benefited from the cost. The following are examples of some of the logical or observable correlations used to allocate costs contained on Accounts Payable documents: • Quantity (units, count, etc.) • Measurement or size (length, space, columnar inch, etc.) • Volume (barrels, gallons, liters, etc.) • Weight (ounce, pound, ton, etc.) • Hours (hours of professional or contract services) • Labor dollars (charge is in the same proportion as the labor hours of the department) • Number of customers, meters, employees, etc. • Revenue dollars • Plant in service • Square footage

SHARED ASSETS DISTRIBUTION

Description:	Shared assets are defined as capitalized assets that are owned by one legal entity but are used for the benefit of multiple entities. This would include land structures and improvements, office furniture and equipment, computer and communication equipment, and some software systems that are used by employees in the performance of their jobs.
Provider of Service:	Operating companies or affiliates
User of Service:	Service Company, operating companies and affiliates
Method of Allocation:	All allocations are billed through the Service Company and charged to a Service Company internal order that will assign the costs using a cost causative method to the companies benefiting shared assets. For IT related assets, the costs will be charged to the system application or service internal order. For facility assets, the costs will be charged to the respective Service Company facilities ACC that will assign the costs following employee labor.

FACIALITIES DISTRIBUTION

Description:	Facilities costs are assigned or allocated to the functional areas of operating companies and other affiliates who benefit from the use of the facilities. Depending on whether a building is used by one utility company or is a "shared" building, i.e., building used by employees of more than one operating company or affiliate, facility costs may include: Single-utility facility: The administrative property services labor and non-labor costs, utility expenses, maintenance costs for structures and systems, pro-rated share of property taxes (for owned buildings), and the rent and occupancy expenses (for leased buildings). Shared facility: Administrative property services labor and non-labor costs, utilities expenses, and the maintenance costs for structures and systems are captured. If the building is leased, the rent is included. If the building is owned, the carrying costs of the shared assets, such as the depreciation and a return on rate base, are included in the facilities' cost. The Property Services department is responsible for the owned and leased facility.
Provider of Service:	Service Company or operating companies
User of Service:	Service Company, operating companies, and affiliates
Method of Allocation:	Costs for a single-utility facility are accumulated in the ACC of the company benefitting from the use of the building and are then allocated to functional FERC rent accounts based on the most recent quarter's labor charges. Costs related to a shared facility, i.e., buildings used by employees of more than one operating company or affiliate, are first accumulated in ACC's specific to the shared facility and then distributed to each operating company and affiliate based upon the most recent quarter's labor for the specific employees located in each facility. Once costs are assigned to the appropriate company, they are then allocated to the functional FERC rent accounts based on the most recent quarter's labor charges.

MONEY POOL

Description:	Through the Utility Money Pool ("UMP"), temporary surplus funds of Xcel Energy are available for short-term loans to other operating companies with cash needs.
Provider of Service:	Service Company
User of Service:	PSCo, NSPM, SPS
Method of Allocation:	An operating company can borrow from, and make loans to, the UMP, which is administered at cost by the Service Company. In addition, the holding company can deposit surplus funds into the UMP but cannot borrow from the UMP. Interest income or expense is charged or credited, as appropriate, to the UMP participants. All charges are directly billed from the Service Company to the appropriate operating company. NSPM petitioned for and received approval on the use of a UMP in Docket No. AI-04-100.

CUSTOMER BILLING

Description:	NSPM bills customers for electric, gas, propane, and miscellaneous non-regulated activities through the customer billing system.
Provider of Service:	Operating companies
User of Service:	Operating companies, including utility operations, jurisdictions, and non-regulated activities.
Method of Allocation:	Costs related to customer billing are direct charged to specific operating companies whenever possible. When costs cannot be directly assigned to a specific operating company, they are allocated based on the number of customers. Non-regulated activities that use the customer billing system are allocated a customer accounting overhead based on revenue dollars. See Section VII.

ENGINEERING AND SUPERVISION ("E&S") OVERHEAD

Description:	E&S costs are capitalized as construction overheads. E&S overheads are applied where it is not practical to direct charge the pay and expense of the engineers, surveyors, draftsmen, inspectors, first line management, and their assistants to construction. NSPM uses the E&S overhead allocation to charge these expenses to capital projects.
Provider of Service:	Operating companies and Service Company
User of Service:	Operating companies.
Method of Allocation:	Costs related to E&S are gathered in an ACC separately by functional class and utility (production, transmission, and distribution). The ACC's are fully allocated on a monthly basis to clear the balances to zero. These costs are sent to the fixed asset ledger and then are allocated to each eligible capital internal order based on current month charges and the calculated rate. The fixed asset ledger tracks all capital projects and work order expenditures for Xcel Energy on a life-to-date basis. Once expenditures are recorded on the books of the appropriate legal entity, the fixed asset ledger system generates the overhead allocations, and if appropriate, AFUDC, which are then applied to the individual internal orders. In addition, the fixed asset ledger calculates monthly depreciation by legal entity and handles the transfer of work orders from FERC account 107, Construction Work in Progress; to FERC account 106, Completed Construction-Not Unitized; to FERC account 101, Utility Plant in Service. The transfer of non-utility costs is within FERC account 121, Non-Utility Property using sub accounts.

CAPITAL A&G

Description:	A&G costs are capitalized as construction overheads. The overhead relates to all the personnel in the administrative office that work on construction to assure its continued operation but are not direct to any one project. A prime example is the payroll analyst whose responsibility it is to assure the construction labor receives its payroll checks. Because it is inefficient for these employees to direct charge all the work orders an overhead process is used to facilitate charging the capital work orders.
Provider of Service:	Operating companies and Service Company
User of Service:	Operating companies.
Method of Allocation:	Each operating company performs an A&G study every other year to review the time employees in certain administrative departments spend on capital work. A percent of payroll for these employees, based on the A&G study results is charged to an overhead allocating cost center, one-twelfth each month. The overhead cost center is allocated to each work order based on current month charges.

VI. UTILITY ALLOCATIONS

OVERVIEW

NSPM's costs are directly assigned or allocated to electric, gas, or non-regulated activities whenever possible or charged as common and then allocated to the electric and gas utilities using utility allocations. Common utility costs are grouped into two categories: (1) O&M utility allocations and (2) rate base and non-O&M utility allocations. The O&M utility allocations are processed monthly within SAP and are explained below. The common rate base and non-O&M utility allocations are completed as part of an annual study and for rate case filing purposes which are explained below.

O&M UTILITY ALLOCATIONS

Introduction

Common O&M utility allocations are applied to common costs that are recorded in A&G (FERC accounts 920-935), customer accounting, and customer information and sales (FERC accounts 901-917). Table A in this section lists the NSPM allocation methodology applied to each FERC account or range of FERC accounts.

Methodology

NSPM uses the following methods to allocate common O&M costs. These methods were developed to achieve the most cost causative relationship that each FERC account or range of FERC accounts has with electric and gas utility operations. The allocators used are as follows:

Customer Allocator

The customer allocator is used to allocate common utility costs in FERC accounts 901-903, and the non-commodity bad debt portion of FERC 904 and 905-917 among electric and gas operations. The allocation is based on the customer bill counts for the electric and gas utilities. The allocator used in the current year is developed based on the previous years' actual customer bill count.

Revenue Allocator

The revenue allocator is used to allocate common utility costs for commodity bad debt, recorded in FERC account 904, among electric and gas operations. The allocation is based on a rolling four-year average of actual electric and gas revenues. The allocator in the current year is developed based on the four previous years' actual operating revenues from the corporate income statement.

Three-Factor Allocator

The three-factor allocator is used to allocate common utility costs in FERC account ranges 920-924 and 927-935 among electric and gas utilities. The allocation is based on the weighted average of operating revenue, plant in service, and supervised O&M. The allocator used in the current year is developed based on the previous years' actual operating revenue, plant in service and supervised O&M.

Labor Allocator

The labor allocator is used to allocate common utility costs in FERC accounts 925-926 to the electric and gas departments. The allocation is based on operating labor for the electric and gas utilities. The allocator used in the current year is developed based on the previous years' actual operating labor.

RATE BASE AND NON-O&M UTILITY ALLOCATIONS

Introduction

A study is performed annually, and for rate case filing purposes, to identify all rate base and non-O&M costs that are common among the utility operations of NSPM in order to allocate them to the electric and gas utilities.

Methodology

NSPM uses the following methodology to allocate common rate base and non-O&M costs. These allocation factors were developed to achieve the most cost causative methodology based on the pool of costs being allocated. Table B in this section lists the methodology applied to specific pools of costs. The allocators used are as follows:

Three-Factor Allocator

The allocation is based on the weighted average of operating revenue, plant in service, and supervised O&M. The allocator used in the current year is developed based on the previous years' actual operating revenue, plant in service and supervised O&M.

Computer Software Study

A composite allocator is used to allocate common computer software rate base (plant) and non-O&M (plant related) costs among electric and gas utilities. Software assets and related costs are presented in a cost of service study using a single amount. A study of all computer software is done to determine how each individual software asset that is part of the single amount should be allocated. All individual allocations are summarized to create a single composite allocation that is then applied to the summarized computer software plant and plant related costs.

Transportation Study

Individual allocators are used to allocate common transportation rate base (plant) and non-O&M (plant related) costs among electric and gas utilities. Transportation assets are reviewed to determine where vehicles are used and allocation factors are developed.

Table A – O&M Utility Allocations

FERC Account	Allocation Method	Basis for Allocation Selection
901-917 (excluding commodity bad debt in FERC 904)	Customer Allocator	Customer bill counts are a reasonable methodology to use to allocate common customer accounting and customer information and sales costs recorded in FERC accounts 901-917 because these costs are customer related costs, e.g., credit and collection, customer accounting, bad debt, etc.
904 (commodity bad debt portion)	Revenue Allocator	A revenue allocator is a reasonable methodology to allocate commodity bad debt because these costs have a cost-causative relationship to uncollectible utility revenues.
920-924	Three-factor Allocator	A three-factor allocation is reasonable because there is no single allocator that could provide a cost-causative link. A three-factor allocator that measures three distinct aspects of the Company and results in an overall fair assignment of costs to the electric and gas utilities is used and is based on equally weighting operating revenue, plant in service and supervised O&M.
925-926	Labor Allocator	A labor allocation is reasonable because the costs recorded in these accounts are injuries and damages and pension and benefit costs. These costs have a cost-causative relationship with labor.
927-935	Three-factor Allocator	A three-factor allocation is reasonable because there is no single allocator that could provide a cost causative link. A three-factor allocator that measures three distinct aspects of the Company and results in an overall fair assignment of costs to the electric and gas utilities is used and is based on equally weighting operating revenue, plant in service and supervised O&M.

Table B – Rate Base and Non-O&M Utility Allocations

Utility	Functional Class	Pool of Costs	Allocation Methodology
Electric			Direct Assignment
Gas			Direct Assignment
Common	26/Common Intangible Plant	Computer Software	Computer Software Study
Common	31/Common General Plant	General Furniture & Equipment	Three-Factor Allocation
Common	31/Common General Plant	Electric Distribution – Mass – MN	Direct Assignment to Electric
Common	31/Common General Plant	Electric Distribution – ND	Direct Assignment to Electric
Common	31/Common General Plant	Electric Distribution – MN	Direct Assignment to Electric
Common	31/Common General Plant	Electric Distribution Vaults	Direct Assignment to Electric
Common	31/Common General Plant	Allen S King Plant	Direct Assignment to Electric
Common	31/Common General Plant	Electric Transmission Line – MN	Direct Assignment to Electric
Common	31/Common General Plant	Electric Transmission Substation – MN	Direct Assignment to Electric
Common	31/Common General Plant	Gas Distribution – MN	Direct Assignment to Gas
Common	31/Common General Plant	General Tools and Other Equipment	Three-Factor Allocation
Common	31/Common General Plant	Office, Service & Other Bldgs – MN	Three-Factor Allocation
Common	31/Common General Plant	Office, Service & Other Bldgs – ND	Three-Factor Allocation
Common	31/Common General Plant	Office, Service & Other Bldgs – SD	Three-Factor Allocation
Common	31/Common General Plant	Software – Minnesota	Three-Factor Allocation
Common	31/Common General Plant	Transportation Equipment – MN	Transportation Study
Common	31/Common General Plant	Transportation Equipment – MN	Transportation Study
Common	31/Common General Plant	Transportation Equipment – SD	Transportation Study
Common	31/Common General Plant	Prairie Island	Direct Assignment to Electric
Common	31/Common General Plant	Inver Hills – Prod Other	Direct Assignment to Electric
Common	31/Common General Plant	Big Oaks Rec Area	Three-Factor Allocation
Common	31/Common General Plant	Black Dog	Direct Assignment to Electric
Common	31/Common General Plant	High Bridge	Direct Assignment to Electric
Common	31/Common General Plant	Riverside	Direct Assignment to Electric
Common	31/Common General Plant	Sherco	Direct Assignment to Electric
Common	31/Common General Plant	Gas Prod – Wescott – MN	Direct Assignment to Gas
Common	31/Common General Plant	General Tools and Other Equipment	Three-Factor Allocation
Common	31/Common General Plant	General Plant – MN	Three-Factor Allocation
Common	31/Common General Plant	General Plant – SD	Three-Factor Allocation
Common	31/Common General Plant	General Plant – ND	Three-Factor Allocation

VII. NON-REGULATED ACTIVITY ALLOCATIONS

INTRODUCTION

The purpose of this section is to detail the methods of assigning and allocating costs between the regulated services and the non-regulated activities of NSPM.

NSPM follows the same approach for all types of costs for its fully distributed costing method. As discussed earlier in the CAAM, NSPM's method was approved by the Commission in its electric and gas rate cases (E002-GR-92-1185, G002-GR-92-1186 and G002/GR-97-1606) and the Commission's September 28, 1994 Order in Docket No. G,E-999/CI-90-1008.

The Commission established the following hierarchical cost assignment and allocation principles in Docket No. G,E-999/CI-90- 1008:

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

This process accomplishes the proper separation of costs between NSPM's regulated utility business and non-regulated activities. Each activity that could be considered as being outside of NSPM's electric and gas business is reviewed for regulated/non-regulated treatment. If the activity is approved to be treated as a non-regulated operation, the non-regulated cost allocation process is followed.

There are limited situations where an activity that would be in the public interest could not be pursued if a fully distributed costing approach was followed. In such circumstances, NSPM has filed, and will continue to file, any deviation from a fully distributed costing process on a project-specific basis. Any existing exceptions have been filed and approved by the Commission.

Evaluation Process

NSPM's approach to fully distributed costing includes the following steps of analysis: business profile, direct charging, labor overheads, cost causation allocation, labor related overhead, and corporate residual allocation. Non-NSPM affiliates are charged a working capital fee as discussed in Section IV.

Business Profile

The allocation process begins by reviewing each non-regulated activity for the services NSPM's utility business will be providing to the non-regulated activity.

Direct Charging (Addresses Principle #2)

Cross charges between NSPM service providers and non-regulated activities are reviewed with the business. Any process, project, or service performed for the direct benefit of a non-regulated activity is directly charged to the non-regulated activity. The business area providing service to the non-regulated activity communicates the anticipated level of service and how much the service will cost.

Labor charges are directly assigned to the non-regulated activity within the budgeting process, generally based on historical charges and taking into consideration known changes. The non-labor charges are directly charged. This process enables charging for all service that will be provided.

Cost Causation Allocations (Addresses Principle #3)

If no direct charge has been established for a service expected to be provided, a cost causation allocation is developed. Direct charging is preferred. However, if a service is expected to be provided and was not budgeted as a direct charge, an estimate of the cost of the service is made and allocated to the non-regulated business. An example of this would be, when a service is being provided, but it is at such a minimal level that it would be very difficult or cost prohibitive to charge on a direct basis.

Overhead Costs (Addresses Principle #4)

The overhead allocation factors capture indirect costs associated with providing services to non-regulated activities.

NSPM currently uses a labor overhead rate developed by reviewing the expenses incurred in support of employee related activities (such as employee programs, employee relations, training, employment, compensation and benefits program development costs, diversity, safety), office equipment needs, and supervision of the service provider. The labor overhead is applied to fully loaded labor. The labor related overhead is applied to non-regulated services wholly contained within NSPM and affiliate or third party transactions.

For non-regulated services wholly contained within NSPM, a portion of NSPM's corporation costs are allocated based on a two-factor formula that takes into consideration the relative size of the non-regulated business by using number of employees and revenues.

Working Capital Fee (Addresses Principle #3)

The working capital fee is applied to non-NSPM affiliates. The fee is based on the current Prime Rate and is reviewed and updated quarterly. This fee is to compensate the regulated business for the cost of working capital used by affiliates.

VIII. JURISDICTIONAL ALLOCATIONS

INTRODUCTION

NSPM's methods for assigning and allocating common O&M costs, plant and plant related, and other rate base investment to jurisdictions is intended to distribute costs in a manner that most closely reflects the benefit received from the expenditure. Accurately stating the assigned and allocated costs of the Company, as they relate to causation of the costs, is a fundamental part of creating a fair distribution of those costs to jurisdiction.

NSPM uses three methods to assign and allocate O&M expense, plant and plant related, and other rate base investment to jurisdiction:

1. direct assignment based on FERC account and location,
2. allocate based on cost causation, and
3. allocate based on a default allocator.

Determination of the assignment and allocation of costs to jurisdiction is an annual process designed to identify the jurisdiction(s) that receive the benefit from the cost or investment. During the review, the three methods stated above are used to ensure that the appropriate jurisdiction(s) is assigned or allocated the cost. It is NSPM's primary goal to direct assign or allocate based on cost causation as often as possible, and allocate based on a default as little as possible.

The first step in assigning costs and investments to a jurisdiction is to identify all costs that can be directly assigned to a jurisdiction (Minnesota, North Dakota or South Dakota), based on the location where work is being performed. For O&M expense, the SAP general ledger account has a location indicator (Profit Center) and a FERC account number associated with it and these are used to determine the appropriate jurisdiction(s) for assigning costs. The individual business areas determine and maintain the appropriate values for these codes based on the type of work being performed and which customers benefit from it. For plant investment data, the PowerPlan system's functional class ID, state code and the function that it is serving are used to determine the appropriate jurisdictions to assign costs for plant, plant related and other rate base costs.

Direct Assignment Based on FERC Account and Location

The first method NSPM uses is to direct assign costs whenever possible. For example, the distribution portion of an electric substation (that which is assigned to a distribution FERC account function) and is located in the Twin Cities metro area can be directly assigned to the Minnesota jurisdiction based on location as it directly serves only customers in Minnesota. In addition, all gas transmission and distribution property are directly assigned to the jurisdiction based on where the property is located as defined within the PowerPlan system. The Capital Asset Accounting organization maintains the capitalized property data.

An O&M example of direct assignment (expense) would be either electric or gas special meter reading done in the Twin Cities metro area (assigned to a distribution FERC account). The meters read are for customers in the State of Minnesota; therefore, the related costs are directly assigned to the Minnesota jurisdiction.

All regulatory expenses specific to a jurisdiction are directly assigned to that jurisdiction. For example, indirect assessments charged to NSPM, from the Minnesota Department of Commerce and the Commission, are directly assigned to the Minnesota jurisdiction.

Allocation Based on Cost Causal Relationship

The second method NSPM uses identifies all investments and costs that can be assigned to jurisdiction based on a causal relationship, and allocates these costs using the most cost causal allocation method. Examples of electric and gas analyses are as follows:

Electric

NSPM operates an integrated electric transmission system that transports electricity to NSPM's distribution system that in turn, supplies electricity to all of NSPM's customers. The transmission system is built to meet the demand created by serving its customers and, therefore, NSPM uses a coincident peak transmission demand taken from twelve consecutive months that constitute a calendar year method, to allocate transmission investment to all of its jurisdictions. All of the expense and plant investment, assigned to transmission function, exists to support NSPM's infrastructure, is fixed in nature and is assigned to jurisdiction based on transmission demand.

The cost causation allocators used for electric production expense or plant investment is a twelve-month coincident peak demand or energy, depending on the type of expense or plant investment. If the expense is variable in nature, energy is used to make the assignment to jurisdiction. If it is determined that the expense or plant investment exists to support NSPM's infrastructure and is fixed in nature, the demand allocator is used to make the assignment to jurisdiction.

Gas

From a supply standpoint, for example, NSPM operates its gas distribution system as a single unit. NSPM purchases natural gas, pipeline delivery capacity, and transmission of gas purchased to meet its customers' requirements on a system-wide basis. In addition, NSPM also operates propane-air (LPG) peak shaving facilities and liquefied natural gas (LNG) peaking facilities to meet firm demand in excess of natural gas daily pipeline entitlement for the benefit of the entire NSPM system. Because these types of costs support the entire operating company system, it is not possible to direct assign them to a specific jurisdiction. For this example, the O&M production and storage functions are allocated to jurisdiction based on the type of expense within the FERC account number. The transmission function is allocated based on the gas load dispatch allocator that is a combination of the design day firm demand allocator and total annual throughput. For plant investment, all production and storage facilities are allocated based on the gas design day allocator related to the design day firm demand.

Electric & Gas

Cost and investment in support of NSPM's distribution, customer accounting, and customer information & sales are more easily identified by state based on the location or where the work is being performed, or they can be allocated to jurisdiction using customers as a basis. In cases where services are provided and serve all regional customers, a regional allocator is developed which reflects the number of customers served in Minnesota and North Dakota or Minnesota and South Dakota, depending on the region. This represents a causal relationship between costs incurred in those regions and the assignment of costs to jurisdiction. Locating services performed in the Fargo area is an example of these types of costs. Locating services are performed for customers on both sides of the Minnesota/North Dakota border and are, therefore allocated to jurisdiction based on the number of year-end average customers in the North Dakota Region, which includes Fargo, Moorhead, Grand Forks, East Grand Forks and Minot.

Allocation Based on a Default Allocator

Allocation of common and general investment or A&G expense: costs and investment that cannot be assigned to jurisdiction using either direct assignment or allocation based on cost causation as described above are allocated to jurisdiction using a default allocator.

Common and General Plant Investment

The default allocator for electric plant investment is determined by the function that it serves. Common and general plant that serves production uses a twelve-month coincident peak demand allocator to allocate costs to jurisdiction. Plant serving transmission uses a twelve-month coincident peak transmission demand allocator to allocate costs to jurisdiction. For plant serving distribution, the number of year-end average customers is used to allocate costs to jurisdiction.

For Gas plant a default allocator is also determined by the function that it serves. For general and common plant, a year-end average customer allocator is used as the default. If the investment function has been determined to be gas production related, then the default jurisdictional allocator used in the production allocator is gas design day.

Administrative and General Expenses

When assigning or allocating A&G expenses to jurisdiction, a cost causative allocator is used if a functional relationship is easily established. In other instances, Electric A&G costs are allocated to jurisdiction using an equally weighted two-factor allocator based on electric plant in service and electric O&M expense (excluding A&G). The two factor allocator is developed by first calculating a three part historical ratio of plant investment directly serving production, transmission or distribution and a three part historical ratio of O&M expenses assigned to FERC accounts that are either production, transmission or directly serve customers (distribution, customer accounting, customer information or sales). These two ratios are then averaged to develop an equally weighted production, transmission and distribution ratio. This resulting three part ratio is then multiplied times the jurisdictional O&M default allocation ratios. The electric production portion is allocated to jurisdiction using a twelve-month coincident peak demand allocator; the transmission portion using the transmission demand allocator; and the customer portion is allocated using twelve-month end-of-year customers. The final step is to add the three sets of jurisdictional ratios together to form the two factor jurisdictional allocator used to allocate electric A&G costs supporting corporate functions.

Gas A&G expenses are allocated to jurisdiction using the appropriate customer allocation as a default allocator, based on the SAP account location indicator (profit center).

A more detailed description of each allocation type and method of allocation, including examples of why the allocation was chosen to assign costs to jurisdiction is included below.
Table C in this section lists the methodology applied to specific pools of costs.

ALLOCATION METHODS

GAS & ELECTRIC

Allocation: Direct Assigned

This allocation type is used to assign all expenses that are determined to be directly assignable to a jurisdiction (Minnesota, North Dakota, and South Dakota).

Allocation: Direct Assigned: State of Minnesota

This allocation type is used for all expenses that are determined to be for the direct benefit or in direct support of the Minnesota jurisdiction. The types of costs direct assigned include: direct and indirect assessments related to one of Minnesota's regulatory bodies, legal department expense budgeted in support of Minnesota, economic development activities in the state of Minnesota, facilities expenses in support of the distribution business unit in the state of Minnesota, delivery system operation and maintenance costs in the Twin Cities metro area, Northwest and Southeast regions and automated energy system (AES) expenses.

Allocation: Direct Assigned: State of North Dakota

This allocation type is used for all expenses that are determined to be for the direct benefit or in direct support of the state of North Dakota jurisdiction. The types of costs direct assigned include: regulatory development activities based out of the North Dakota regional offices, direct and indirect assessments related to the North Dakota regulatory bodies, legal department expenses budgeted in support of North Dakota, economic development activities performed directly for North Dakota and work performed in the Minot area for the sole benefit of North Dakota customers.

Allocation: Direct Assigned: State of South Dakota

This allocation type is used for all expenses that are determined to be for the direct benefit or in direct support of the state of South Dakota jurisdiction. The types of costs direct assigned include: direct and indirect assessments related to the South Dakota regulatory bodies, legal department expenses budgeted in support of South Dakota, economic development activities performed directly for South Dakota.

Allocation: Customers - Year-End Average - (Electric or Gas)

This allocation type is used to assign expenses where there is a cost causative relationship between the number of electric and gas utility NSP customers in a particular area and the service provided. This allocator is based on year-end average customer by utility.

Allocation: Customers Year-End Average Minnesota Co. MN/ND/SD

This allocation type is used to assign costs to all of Minnesota Company's jurisdictions (Minnesota, North Dakota, and South Dakota) when the work performed benefits all of the company's customers equally. This is the default allocator that is used for the electric and gas distribution, customer accounting, customer information, sales, and A& G FERC accounts.

This is also the gas utility A&G corporate function default allocator type.

Allocation: Customers Year End Average Minnesota/North Dakota

This allocation type is used to assign costs to both the North Dakota and Minnesota jurisdictions based on customers in the entire North Dakota region. This includes customers in Fargo, Moorhead, Grand Forks, East Grand Forks and Minot service areas. This method is the default allocator for O&M expenses associated with general ledger accounts where the SAP profit center designates support for Minnesota/North Dakota.

Allocation: Customers Year End Average Minnesota/South Dakota

This allocation type is used to assign costs to both the South Dakota and Minnesota jurisdictions based on customers in the entire South Dakota region. This method is the default allocator for O&M expenses associated with general ledger accounts where the SAP profit center designates support for Minnesota/South Dakota.

Allocation: Study Jurisdictional Budget Transmission

This allocation is used for all budgeted plant investment that is determined to be for the direct benefit or in direct support of transmission. It is a historical allocator based on the plant investment that has been direct assigned to jurisdiction based on its state location.

Allocation: Study Jurisdictional Budget Distribution

This allocation is used for all budgeted plant investment that is determined to be for the direct benefit or in direct support of Distribution. It is a historical allocator based on the plant investment that has been direct assigned to jurisdiction based on its state location.

ELECTRIC UTILITY ONLY

Allocation: Energy

Fuel and fuel-related items are assigned to jurisdiction based on the energy allocator because of the direct correlation of customer sales and the level of fuel consumed. These items include all fuel, purchased energy, interchange agreement energy, and variable production expenses.

Allocation: Demand Prod (Coincident Peak)

The 12 coincident peak (CP) demand production allocator is used to assign fixed capacity related expenses, plant, and plant related items to jurisdiction. Other expenses allocated to jurisdiction based on demand include: fixed production expenses, purchased power demand expense, interchange agreement demand charges and regulatory expenses not directly related to one of NSPM's jurisdictions. Also, any A&G costs that are directly in support of production are allocated using this method.

Allocation: Demand Tran (Coincident Peak)

The 12 CP demand transmission allocator is used to assign transmission FERC Accounts in support of NSPM's jurisdictions. Also, any A&G costs that are directly in support of transmission are allocated using this method.

Allocation: Two-Factor Allocator (A&G Only)

Expressed as an equally weighted factor based on electric plant in service and electric O&M expense (excluding A&G); the two-factor allocator is used to allocate electric A&G costs when there is not a direct or cost causative method available. Generally, all corporate electric A&G costs are allocated using this method.

GAS UTILITY ONLY

Allocation: Retail Revenues Cost of Gas Recovery - Demand, Commodity and Purchased Gas Adjustment True-up Study

Retail revenues include components for the recovery of costs associated with product and delivery of product to the service area. Such costs include capacity or entitlement costs, pipeline transportation costs, commodity costs and costs of alternative gas (LPG or LNG) supplied during times of firm peak demand. Regulations provide for the automatic adjustment of billing rates for price changes and the annual true up of the cost of gas incurred. Demand, commodity, and purchased gas adjustment are components of the retail revenues cost of gas recovery study. The portion of total NSPM cost of gas included in retail revenues that the Minnesota jurisdiction represents is also applied to total Minnesota company cost of gas expense accounts to achieve revenue neutrality for revenue requirements consideration.

Allocation: Design Demand Day

Expressed as a percentage, design demand day is the ratio of the Minnesota jurisdiction firm peak demand volume to the total NSPM firm peak demand volume that could occur on the distribution system on a day considered to be the most severe weather conditions that can be experienced.

Allocation: Load Dispatch

Expressed as a percentage, load dispatch is a combination of the Minnesota jurisdiction design demand day and the Minnesota jurisdiction total retail sales and transportation throughput each weighted equally.

Allocation: Limited Firm and Standby Services Study

Expressed as a percentage, limited firm and standby services, in revenues, is the ratio of Minnesota jurisdiction availability charges and volumetric charges to the total NSPM system; in costs, it is the ratio of Minnesota jurisdiction volumetric product costs to the total NSPM program product costs.

Table C

Allocation to Jurisdiction

Selection Criteria *							
Sub-Business Unit	**Plant Function**	**Functional Class ID / Description**	**Location**	**Functional Use**	**Utility**	**Jurisdiction**	**Allocation Methodology**
Budget							
Production	Production	1 / Electric Steam Production Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	2 /Electric Nuclear Production Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	3 / Electric Hydro Production Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	4 / Electric Other Production Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	4 / Electric Other Production Plant-Wind			Electric	MN/ND/SD/WHSL	Electric - Energy
Production	Production	22 / Nuclear Fuel			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	26 / Common Intangible Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	29 / Electric General Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	31 / Common General Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	23 / Decommissioning	FERC MN		Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	23 / Decommissioning	Minnesota		Electric	MN	Direct Assigned - State of Minnesota
Production	Production	23 / Decommissioning	North Dakota		Electric	ND	Direct Assigned - State of North Dakota
Production	Production	23 / Decommissioning	South Dakota		Electric	SD	Direct Assigned - State of South Dakota
Production	Production	23 / Decommissioning	Wisconsin		Electric	WI	Direct Assigned - Wisconsin
Electric Transmission	Transmission	5 / Electric Transmission Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Transmission	Transmission	5 / Transmission Direct Assignment	Minnesota	DRCT	Electric	MN	Direct Assigned – State of Minnesota
Electric Distribution	Transmission	5 / Transmission Serving Distribution	Minnesota		Electric	MN	Direct Assigned - State of Minnesota
Electric Distribution	Transmission	5 / Transmission Serving Distribution	North Dakota		Electric	ND	Direct Assigned - State of North Dakota
Electric Distribution	Transmission	5 / Transmission Serving Distribution	South Dakota		Electric	SD	Direct Assigned - State of South Dakota
Production	Transmission	5 / Transmission Generation Step-up		BSLD, PEAK	Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Electric Transmission	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Transmission	Common & General	26 / Common Intangible Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)

Selection Criteria *							
Sub-Business Unit	**Plant Function**	**Functional Class ID / Description**	**Location**	**Functional Use**	**Utility**	**Jurisdiction**	**Allocation Methodology**
Budget							
Electric Transmission	Common & General	29 / Electric General Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Transmission	Common & General	31 / Common General Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Distribution	Distribution	6 / Electric Distribution Plant	Minnesota		Electric	MN	Direct Assigned - State of Minnesota
Electric Distribution	Distribution	6 / Electric Distribution Plant	North Dakota		Electric	ND	Direct Assigned - State of North Dakota
Electric Distribution	Distribution	6 / Electric Distribution Plant	South Dakota		Electric	SD	Direct Assigned - State of South Dakota
Electric Distribution	Distribution	6 / Electric Distribution Plant	Wholesale		Electric	WHSL	Direct Assigned - Wholesale Full Requirements
Production	Distribution	6 / Distribution Generation Step-up		PEAK	Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Electric Transmission	Distribution	6 / Distribution Serving Transmission		TBULK	Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Distribution	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Electric Distribution	Common & General	26 / Common Intangible Plant			Electric	MN/ND/SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Electric Distribution	Common & General	29 / Electric General Plant			Electric	MN/ND/SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Electric Distribution	Common & General	31 / Common General Plant			Electric	MN/ND/SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Gas	Production	7 / Gas Manufactured Production Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Storage	9 / Gas Underground Storage Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Transmission	10 / Gas Transmission Plant			Gas	MN	Direct Assigned – State Of Minnesota
Gas	Transmission	10 / Gas Transmission Plant			Gas	ND	Direct Assigned – State of North Dakota
Gas	Distribution	11 / Gas Distribution Plant			Gas	MN	Direct Assigned – State of Minnesota
Gas	Distribution	11 / Gas Distribution Plant			Gas	ND	Direct Assigned – State of North Dakota
Gas	Common & General	25 / Gas Intangible Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Common & General	26 / Common Intangible Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Common & General	30 / Gas General Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Common & General	31 / Common General Plant			Gas	MN/ND	Gas - Design Demand Day

Selection Criteria *							
Sub-Business Unit	Plant Function	Functional Class ID / Description	Location	Functional Use	Utility	Jurisdiction	Allocation Methodology
Budget							
Gas	Common & General	25 / Gas Intangible Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	26 / Common Intangible Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	30 / Gas General Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	31 / Common General Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	34 / Gas Other Storage Plant			Gas	MN/ND	Gas - Design Demand Day

* All items under the Selection Criteria must be met before this allocation takes place.

Line No.	Description	Allocation Basis
	The allocation factors on this page were used to determine North Dakota jurisdictional amounts for all of the years presented in these schedules.	
1	Production	Demand/Energy
2	Transmission	Demand
3	Distribution	Customers/Direct Assigned
4	Customer Accounting	Customers/Direct Assigned
5	Customer Service & Information	Customers/Direct Assigned
6	Sales, Econ Dvlp & Other	Customers/Direct Assigned
7	Administrative & General	Customers/Two Factor/Demand/Direct Assigned

		Test Year 2021		
Line No.	Allocation Factor	Total Utility	North Dakota Jurisdiction	Allocation Factor
1	Demand	61,141,909	3,774,380	6.1731%
2	Energy	32,530,391	2,203,565	6.7739%
3	Customers	1,507,412	94,349	6.2590%
4	Two-Factor			6.1963%

(4) Two-Factor Allocator (A&G Only) See page 3
Expressed as an equally weighted factor based on electric plant in service and electric O&M expense (excluding A&G).
These costs are then allocated to jurisdiction based on the O&M default for that Regulatory Business Unit.
The production and transmission portions are allocated to jurisdiction using a 12 CP demand allocator, and the customer portion is allocated using 12- month end-of-year average electric customers.

Alloctors for Common and General Plant
for 2021 Budget
Based on 2019 Actual Data

O&M Allocator

O&M excluding A&G	2019 Actuals	Ratio
Production	624,832,053	63.98%
Transmission	61,655,592	6.31%
Distribution/Customer	290,082,379	29.70%
	$ 976,570,024	99.99%

Plant in Service used to allocate Electric General Plant
Source - 2019 FERC Form 1
Pages 204-207

	2019 Year End Balance	Ratio
Production	$ 9,602,782,087	54.24%
Transmission	$ 3,795,518,974	21.44%
Distribution	$ 4,306,162,495	24.32%
	$ 17,704,463,556	100.00%

Combined Allocator used for Electric Portion of Common Plant
Equally Weighted Plant in Service and O&M ratio

Production	59.1100%
Transmission	13.8800%
Distribution	27.0100%
	100.0000%

21 Budget Allocators

EProd Demand Alloc

MN	86.9972%
ND	6.1731%
SD	6.8297%
WHLSL	0.0000%
	100.0000%

ETrans Demand Alloc

MN	86.9972%
ND	6.1731%
SD	6.8297%
WHLSL	0.0000%
	100.0000%

ECustomerMN/SD/ND

MN	87.2853%
ND	6.2590%
SD	6.4557%
WHLSL	0.0000%
	100.0000%

2021 Budget A&G Jurisdicational Allocators

ELECTRIC A&G Alloc

2 Factor Allocator	O&M and Plant	MN	ND	SD	WHLSL	Check
Production	59.1100%	51.4240%	3.6489%	4.0370%	0.0000%	59.1099%
Transmission	13.8800%	12.0752%	0.8568%	0.9480%	0.0000%	13.8800%
Distribution/Customers	27.0100%	23.5758%	1.6906%	1.7437%	0.0000%	27.0101%
Resulting Allocator	**100.00%**	**87.0750%**	**6.1963%**	**6.7287%**	**0.0000%**	**100.0000%**

Line No.	Description	Allocation Basis
	The allocation factors on this page were used to determine North Dakota jurisdictional rate base amounts for all of the years presented in these schedules.	
	The following allocation factors are used to compute North Dakota jurisdictional amounts for Plant-in-Service, Accumulated Depreciation, Accumulated Deferred Income Tax and Construction Work in Progress:	
1	Production	Demand/Energy
2	Transmission	Demand
3	General	Demand/Customers/Direct Assigned
	Production	
	Transmission	
	Other	
4	Common	Demand/Customers/Direct Assigned
	Production	
	Transmission	
	Other	
	In addition, the following allocation factors are used to compute North Dakota jurisdictional amounts:	
5	Other Rate Base:	
	Materials & Supplies	Demand/Customers/Direct Assigned
	Non-Plant Assets & Liabilities	Demand/Customers/Direct Assigned
	Prepayments	Demand/Customers/Direct Assigned
	Fuel Inventory	Energy

		Test Year 2021		
Line No.	Allocation Factor	Total Utility	North Dakota Jurisdiction	Allocation Factor
1	Demand	61,141,909	3,774,380	6.1731%
2	Energy	32,530,391	2,203,565	6.7739%
3	Customers	1,507,412	94,349	6.2590%

Northern States Power Company
Electric Utility - State of North Dakota
Average Rate Base
($000's)

Case No. PU-20-____
Exhibit ___ (BCH-1)
Schedule 15, Page 1 of 3

Line No.	Description	Proposed 2021 Test Year Average Rate Base (A)
	Electric Plant as Booked	
1	Production	$885,937
2	Transmission	240,321
3	Distribution	213,025
4	General	72,035
5	Common	60,477
6	TOTAL Utility Plant in Service	$1,471,794
	Reserve for Depreciation	
7	Production	$471,529
8	Transmission	60,624
9	Distribution	80,327
10	General	36,969
11	Common	28,392
12	TOTAL Reserve for Depreciation	$677,840
	Net Utility Plant in Service	
13	Production	$414,408
14	Transmission	179,697
15	Distribution	132,698
16	General	35,066
17	Common	32,085
18	Net Utility Plant in Service	$793,954
19	Utility Plant Held for Future Use	$0
20	Construction Work in Progress	$1,914
21	Less: Accumulated Deferred Income Taxes	$147,245
22	Cash Working Capital	($7,103)
	Other Rate Base Items:	
23	Materials and Supplies	$10,807
24	Fuel Inventory	6,579
25	Non-Plant Assets & Liabilities	8,415
26	Customer Advances	(62)
27	Customer Deposits	(71)
28	Prepaids and Other	5,160
30	Regulatory Amortizations	4,409
31	Total Other Rate Base Items	$35,235
32	Total Average Rate Base	$676,755

Northern States Power Company
Electric Utility - State of North Dakota
Comparison of Detail Rate Base
($000's)

Case No. PU-20-____
Exhibit ___ (BCH-1)
Schedule 15, Page 2 of 3

		Proposed Test Year 2021					
		Total Utility			North Dakota Jurisdiction		
Line No.	Description	Unadjusted (A)	Adjustments (B)	2021 Proposed (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	2021 Proposed (F) (D) + (E)
	Electric Plant as Booked						
1	Production	$14,147,508	($19,807)	$14,127,701	$905,744	($19,807)	$885,937
2	Transmission	4,006,532	(7,524)	3,999,008	247,845	(7,524)	240,321
3	Distribution	4,661,029	0	4,661,029	213,025	0	213,025
4	General	1,162,508	(10)	1,162,499	72,045	(10)	72,035
5	Common	975,526	0	975,526	60,477	0	60,477
6	TOTAL Utility Plant in Service	$24,953,102	($27,340)	$24,925,762	$1,499,134	($27,340)	$1,471,794
	Reserve for Depreciation						
7	Production	$7,499,630	$35,005	$7,534,636	$469,658	$1,871	$471,529
8	Transmission	976,779	4,478	981,257	60,469	155	$60,624
9	Distribution	1,797,094	257	1,797,350	80,070	257	80,327
10	General	598,260	(1,814)	596,446	37,083	(114)	36,969
11	Common	461,323	(3,386)	457,937	28,601	(210)	28,392
12	TOTAL Reserve for Depreciation	$11,333,086	$34,540	$11,367,625	$675,882	$1,958	$677,840
	Net Utility Plant in Service						
13	Production	$6,647,877	($54,812)	$6,593,065	$436,085	($21,677)	$414,408
14	Transmission	3,029,753	(12,002)	3,017,751	187,376	(7,679)	$179,697
15	Distribution	2,863,935	(257)	2,863,679	132,954	(257)	132,698
16	General	564,248	1,805	566,053	34,962	104	35,066
17	Common	514,203	3,386	517,589	31,875	210	32,085
18	Net Utility Plant in Service	$13,620,016	($61,880)	$13,558,136	$823,253	($29,299)	$793,954
19	Utility Plant Held for Future Use	$0	$0	$0	$0	$0	$0
20	Construction Work in Progress	$31,626	$0	$31,626	$1,914	($0)	$1,914
21	Less: Accumulated Deferred Income T	$2,486,346	$17,658	$2,504,004	$144,433	$2,812	$147,245
22	Cash Working Capital	($156,183)	$11,666	($144,517)	($7,967)	$864	($7,103)
	Other Rate Base Items:						
23	Materials and Supplies	$174,923	$0	$174,923	$10,807	$0	$10,807
24	Fuel Inventory	97,123	0	97,123	6,579	0	6,579
25	Non-Plant Assets & Liabilities	86,178	2,129	88,307	6,286	2,129	8,415
26	Customer Advances	(9,170)	0	(9,170)	(62)	0	(62)
27	Customer Deposits	(44,930)	0	(44,930)	(71)	0	(71)
28	Prepaids and Other	80,617	0	80,617	5,160	0	5,160
30	Regulatory Amortizations	0	51,639	51,639	0	4,409	4,409
31	Total Other Rate Base Items	$384,741	$53,769	$438,510	$28,697	$6,538	$35,235
32	Total Average Rate Base	$11,393,854	($14,103)	$11,379,750	$701,464	($24,710)	$676,755

Northern States Power Company
Electric Utility - State of North Dakota
COMPARISON OF DETAILED RATE BASE COMPONENTS
Test Year Ending December 31, 2021
($000's)

		Proposed Test Year 2021					
		Total Utility			North Dakota Jurisdiction		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Adjusted (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	Adjusted (F) (D) + (E)
	Construction Work in Progress						
1	Production	$19,060	$0	$19,060	$1,255	$0	$1,255
2	Transmission	2,767	0	2,767	172	0	172
3	Distribution	3,169	0	3,169	76	0	76
4	General	3,342	0	3,342	207	0	207
5	Common	3,289	0	3,289	204	0	204
6	TOTAL Construction Work In Progress	$31,626	$0	$31,626	$1,914	$0	$1,914

		Proposed Test Year 2021					
		Total Utility			North Dakota Jurisdiction		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Adjusted (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	Adjusted (F) (D) + (E)
	Accumulated Deferred Income Taxes						
7	Production	$1,405,009	($4,356)	$1,400,654	$90,948	$821	$91,769
8	Transmission	799,601	(371)	799,230	49,334	(81)	49,253
9	Distribution	637,203	(425)	636,778	30,349	(201)	30,149
10	General	84,334	550	84,884	5,227	39	5,267
11	Common	74,666	1,009	75,675	4,621	71	4,692
12	Net Operating Loss (NOL)	(534,848)	20,263	(514,585)	(37,572)	1,175	(36,397)
13	Non-Plant Related	20,381	988	21,369	1,524	988	2,512
14	TOTAL Accum Deferred Income Taxes	$2,486,346	$17,658	$2,504,004	$144,433	$2,812	$147,245

($000's)

Impact of Unused/(Utilized) Tax Deductions on Rate Base	2020 Bridge EOY Balances	2021 Test Year Annual Activity Amounts	2021 Test Year EOY Balances
1. Unused/(Utilized) Deductions	0	0	0
2. Deferred Tax Effect of Unused/(Utilized) Deductions	0	0	0
3. Unused/(Utilized) Credits State	0	64	64
4. Unused/(Utilized) Credits Federal	30,195	12,339	42,534
5. Accumulated Deferred Income Taxes (ADIT)	**30,195**	**12,403**	**42,598**

Impact of Unused/(Utilized) Tax Deductions on Revenue Requirements	2021 Test Year Utilization Adjustment	Comment
6. Deferred Tax Asset BOY	30,195	From Unused/(Utilized) columns on Line 5
7. Deferred Tax Asset EOY	42,598	From Unused/(Utilized) columns on Line 5
8. Average Rate Base	36,397	(BOY + EOY)/2
9. Return Requirement	2,675	Rate Base * Req Rate of Return
10. RR Tax on Equity Return	630	(T/(1-T))*RB*Equity Return
11. Rate Base Revenue Requirement	3,305	Line 9 + Line 10
12. Deferred Tax	(12,403)	From Unused/(Utilized) columns on Line 5
13. Current Tax Rev Req [1]	12,385	From Line 19
14. Annual Revenue Requirement Increase (Reduction)	**3,287**	Line 10+11+12
[1] *Current Income Tax Rev Req Calculation*		
15. Utilized Deductions	-	From Unused/(Utilized) columns on Line 1
16. Deferred Taxes	(12,403)	Line 12
17. Unused State Tax Credits	64	From Unused/(Utilized) columns on Line 3
18. Unused Federal Tax Credits	12,339	From Unused/(Utilized) columns on Line 4
19. Current Income Tax Revenue Requirement	12,385	(T/(1-T))*(-Line 15+(1-Fed Tax Rate)xLine16+Line17)+(1-Fed Tax Rate)xLine 16+Line 17

Weighted Cost of Capital	2021
Active Rates and Ratios Version	Proposed
Cost of Short Term Debt	1.00%
Cost of Long Term Debt	4.22%
Cost of Common Equity	10.20%
Ratio of Short Term Debt	0.54%
Ratio of Long Term Debt	46.96%
Ratio of Common Equity	52.50%
Weighted Cost of STD	0.01%
Weighted Cost of LTD	1.98%
Weighted Cost of Debt	1.99%
Weighted Cost of Equity	5.36%
Required Rate of Return	**7.35%**

Corp Composite Tax Rate	28.11%
ND Composite Tax Rate	24.40%
Federal Tax Rate	21.00%

Northern States Power Company
Electric Utility - State of North Dakota
Federal Tax Credits
Test Year Ending December 31, 2021
($000's)

PTCs		**2021**
Nobles		
Pleasant Valley		19,595
Border Winds		15,878
Courtenay		18,443
Blazing Star I		22,295
Foxtail		16,590
Lake Benton		10,839
Blazing Star II		21,723
Crowned Ridge		20,978
Freeborn		15,102
Dakota Range		51
Jeffers		4,519
Community Wind North		2,466
Mower		8,859
Total PTCs	$	177,338
R&E	$	5,502
Total Federal Credits	$	182,840
State of ND Energy Allocator		6.7739%
Interchange Agreement Energy Allocation		82.7942%
State of ND Federal Credits (Net of Interchange)	$	10,254
Levelized Credit Method (LCM) Adjustment:		
Border Winds		(637)
Courtenay Wind		(707)
Blazing Star I		(766)
Foxtail		(567)
Lake Benton		(364)
Blazing Star II		(730)
Crowned Ridge		(705)
Freeborn		(477)
Dakota Range		50
Rider removal		(422)
Net Federal Credits in COSS		**4,929**
Rebuttal Adj: LCM (Jeffers, CWN, Mower)		(536)
Adjusted Net Federal Credits in COSS		**4,393**

Full ND Federal Credits are included in the COSS, the LCM adjustment is an adjustment to the Amortization line in the COSS.