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Direct Testimony and Schedules
Benjamin C. Halama

Before the Minnesota Public Utilities Commission
State of Minnesota

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

Docket No. E002/GR-19-564
Exhibit___(BCH-1)

2020 Test Year and 2021-2022 Plan Years
Overall Revenue Requirements
Rate Base
Income Statement

Rate Rider Recovery 2020-2022

November 1, 2019

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Schedules

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 DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have over four 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 attached as Exhibit___(BCH-1), Schedule 1, Resume.

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

A. In my Direct Testimony, I support the Company's Minnesota jurisdiction electric operations cost of service, revenue requirements, and revenue deficiency for each of the three years of the Company's multi-year rate plan (MYRP), which include calendar year 2020 (the test year) and 2021 and 2022 (the plan years). Overall, the net deficiencies and retail revenue requirements for the test year and plan years are summarized in Table 1 below:

Table 1

2020-2022 Revenue Requests

Minnesota Jurisdictional Costs Net of Interchange ($s in millions)

MYRP Year	2020	2021	2022
Amount, cumulative	$201.4	$347.8	$466.1
Amount, incremental	$201.4	$146.4	$118.3
Average % increase, incremental *	6.5%	4.8%	3.9%

* The average percent increase, incremental is calculated using the incremental revenue request over the forecasted present revenues in each applicable year.

I provide the financial data supporting this overall revenue deficiency for the State of Minnesota retail electric jurisdiction, including a description of cost changes, the data we provide, and our selection of the test year. Further, I present:

- our jurisdictional cost of service study and the revenue requirement effects of our utility and jurisdictional allocations; and
- our revenue requirement, including rate base and income statement components with related adjustments and amortizations.

My testimony also supports the 2020 and 2021 requested interim rate increases discussed in the Company's Petition for Interim Rates. Company witness Mr. Gregory P. Chamberlain provides additional support for the interim rate increases proposed as a part of our multi-year rate plan, as does the Notice and Petition for Interim Rates, included in Volume 1 of our Application.

In addition, I explain our treatment of riders, and identify certain compliance requirements addressed in our general rate filing.

I relied on information provided by other witnesses in this proceeding to develop many of the test year revenue requirement adjustments discussed in my Direct Testimony.

Q. HOW IS THE REST OF YOUR DIRECT TESTIMONY ORGANIZED?

A. I present my testimony in the following sections:

- Section II, *Case Overview*, summarizes our jurisdictional revenue requirement for the 2020 test year and 2021-2022 plan years, and discusses the key drivers of cost increases compared to our last MYRP established in Docket No. E002/GR-15-826 (the 2016-2019 MYRP).
- Section III, *Supporting Information*, provides information related to the data provided in our application, the selection of the test year and plan years, and the jurisdictional cost of service study.
- Section IV, *Rate Base*, identifies and explains the components of rate base, and supports the reasonableness of the Company's projected 2020 test year and 2021-2022 plan years rate base.
- Section V, *Income Statement*, identifies and explains the major components of the income statement and supports the reasonableness of the Company's proposed 2020 test year and 2021-2022 plan years income statement.
- Section VI, *Utility and Jurisdictional Allocations*, explains why it is necessary for the Company to allocate costs among its affiliates and between jurisdictions, and describes the utility and jurisdictional

allocators that are used in determining the MYRP revenue requirement.

- Section VII, *Annual Adjustments to the MYRP*, presents adjustments affecting the 2020 test year and 2021-2022 plan years revenue requirements, providing both rate base and income statement impacts.
- Section VIII, *Costs Recovered in Riders*, presents our proposed treatment of costs recovered in riders during the MYRP period, providing details about which riders we propose to continue to use and costs we propose to move into base rates.
- Section IX, *Compliance with Prior Commission Orders*, provides information related to specific requirements from prior Minnesota Public Utilities Commission (Commission) Orders that have not been addressed elsewhere in my testimony.
- Section X, *Conclusion*, summarizes our request.

Q. ARE ALL OF THE DOLLAR VALUES PRESENTED IN YOUR TESTIMONY JURISDICTIONALIZED TO STATE OF MINNESOTA ELECTRIC JURISDICTION?

A. While most of the dollar values presented in my testimony are jurisdictionalized to State of Minnesota Electric Jurisdiction, there are several instances where dollars are either Total Company, or net of Interchange Agreement billings to Northern States Power Company-Wisconsin (NSPW). Dollar values that are Total Company or net of Interchange Agreement billings to NSPW are labeled accordingly.

Q. DO YOU PROVIDE INFORMATION IN COMPLIANCE WITH PAST COMMISSION ORDERS AND COMPANY COMMITMENTS?

A. Yes. Throughout my testimony I note where I am providing information related to prior Commission Orders and Company commitments. In Section IX, I provide additional information related to compliance with prior Commission Orders that have not been addressed elsewhere in my testimony.

II. CASE OVERVIEW

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

A. In this section, I will:

- present the jurisdictional revenue requirement and revenue deficiencies for Minnesota for the 2020 test year and 2021-2022 plan years, referred to in total as the "MYRP Forecast";
- present a summary comparison of the costs in the MYRP Forecast to the costs approved in our last rate case, which include costs in the 2016-2019 MYRP, including changes and true-ups in each year of the MYRP; and
- provide an explanation of the primary sources of the changes in overall costs, including plant-related costs and operations and maintenance (O&M) costs.

A. MYRP Jurisdictional Revenue Requirements and Deficiencies

Q. PLEASE DESCRIBE THE BASIS OF THE COMPANY'S MYRP PROPOSAL.

A. The Company's three-year plan utilizes 2020 as the test year, with 2021 and 2022 as additional plan years developed using budgeted capital additions and budgeted O&M expenses. Also included in the proposal are impacts to other rate base items, sales adjustments, and other adjustments impacting the revenue requirements for these years, so that each year represents a cost of service approach to rate-setting for both capital and O&M.

Q. WHAT IS THE 2020 TEST YEAR JURISDICTIONAL OVERALL REVENUE REQUIREMENT AND REVENUE DEFICIENCY?

A. The overall jurisdiction revenue requirement for the 2020 test year is $3.3 billion. The 2020 test year revenue deficiency, excluding rider roll-ins, is $201.4 million. The 2020 test year revenue deficiency amount represents a 6.5 percent overall increase in retail revenues from base rates compared to projected 2020 retail revenues at present rates. A summary of the 2020 revenue deficiency (in dollars and as a percent) is provided in Exhibit___(BCH-1) Schedule 2, Summary of Revenue Requirements. The calculation of these dollar amounts is provided in Exhibit___(BCH-1) Schedule 3, Cost of Service Study Summary.

Q. WHAT ARE THE OVERALL REVENUE REQUIREMENT AND REVENUE DEFICIENCIES FOR THE 2021 THROUGH 2022 PLAN YEARS?

A. The overall jurisdiction revenue requirements for the 2021 and 2022 plan years are $3.4 billion and $3.5 billion, respectively. The 2021 and 2022 revenue deficiencies, excluding rider roll-ins, are $347.8 million and $466.1 million, respectively. The overall revenue requirement request for the MYRP Forecast represents a 15.2 percent increase in retail revenues from base rates in 2022 compared to projected 2020 retail revenues at present rates. A summary of the 2021 and 2022 revenue deficiencies (in dollars and as percentages) is provided in Schedule 2, Summary of Revenue Requirements.

The calculation of these dollar amounts is provided in Schedule 3, Cost of Service Study Summary.

Q. WHAT IS THE AMOUNT OF THE INTERIM RATE REVENUE DEFICIENCY IN 2020?

A. The Interim Rate Petition (Petition) supports an interim revenue deficiency based on the 2020 test year of $122.0 million, which results in a proposed interim rate increase of 4.1 percent beginning January 1, 2020.

Q. IS AN INTERIM RATE REQUEST FOR 2021 INCLUDED IN THIS FILING?

A. Yes. As discussed in the Direct Testimony of Mr. Chamberlain and in the Notice and Petition for Interim Rates, the Company is also proposing an interim rate adjustment for 2021 as part of its multi-year rate plan filing. The 2021 interim rate revenue deficiency includes an additional $144.0 million beginning on January 1, 2021, which equates to an additional interim rate increase of 4.9 percent in 2021.

Q. HOW DOES THE COMPANY CALCULATE REVENUE REQUIREMENT AND REVENUE DEFICIENCY?

A. The general formula for calculation of the revenue requirement and revenue deficiency is depicted below in Table 2 as follows:

Table 2

Revenue Requirement and Revenue Deficiency

	Item	2020 Test Year Amount ($000s)	2021 Plan Year Amount ($000s)	2022 Plan Year Amount ($000s)	Exhibit__ (BCH-1), Sch. 3 Reference
	Average Rate Base	$8,986,901	$9,309,544	$9,805,740	Page 1, Line 44
multiplied by	Cost of capital	7.45%	7.45%	7.47%	Page 1, Line 20
	Operating Income Requirement	**$669,524**	**$693,561**	**$732,489**	Page 4, Line 158
	Current Retail Revenue	$3,121,140	$3,080,944	$3,069,438	Page 2, Line 47 + Line 48
plus	Current Other Revenue	$545,018	$560,238	$574,740	Page 2, Line 49
equals	Current Total Revenue	$3,666,158	$3,641,182	$3,644,178	Page 2, Line 50
minus	Operating Expenses	$2,313,678	$2,365,673	$2,381,602	Page 2, Line 74
minus	Depreciation Expense	$683,392	$719,524	$760,859	Page 2, Line 76
minus	Amortization Expense	$43,948	$43,475	$44,757	Page 2, Line 77
minus	Taxes	$127,994	$97,781	$90,108	Page 3, Line 135
plus	AFUDC	$28,846	$31,000	$33,500	Page 4, Line 140 + Line 141
equals	**Total Available for Return**	**$525,991**	**$445,729**	**$400,352**	Page 4, Line 143
	Operating Income Requirement	$669,524	$693,561	$732,489	Page 4, Line 158
minus	Total Available for Return	$525,991	$445,729	$400,352	Page 4, Line 143
equals	**Income Deficiency**	**$143,533**	**$247,832**	**$332,137**	Page 4, Line 160
multiplied by	Gross Revenue Conversion Factor	1.403351	1.403351	1.403351	Page 4, Line 162
equals	**Revenue Deficiency**	**$201,426.70**	**$347,794.68**	**$466,104.28**	Page 4, Line 163
plus	Current Retail Revenue	$3,121,140	$3,080,944	$3,069,438	Page 4, Line 166
equals	**Total Revenue Requirement**	**$3,322,566**	**$3,428,739**	**$3,535,542**	Page 4, Line 168

Q. HAS THE COMPANY PROVIDED AN EXPLANATION OF THE ASSUMPTIONS AND APPROACHES USED IN DEVELOPING THE TEST YEAR OPERATING INCOME?

A. Yes. An explanation is provided in the Financial Information section of Volume 3 (Required Information) of this Application. In addition, work papers supporting the 2020 test year cost of service are provided in Volume 4 (MYRP Workpapers) of this Application.

Q. HOW DOES THE COMPANY TREAT CAPITAL AND O&M COSTS IN THE 2020-2022 MYRP?

A. Our proposal uses the following reasoning to develop costs:

1. Capital, capital-related, and O&M costs follow the Company's budget, except as needed to comply with prior Commission Orders or adjustments the Company is specifically proposing in this proceeding. (Capital-related consists of depreciation and allowance for funds used during construction (AFUDC) as well as the cost of capital).
2. Fuel revenues and expenses for all years of the 2020-2022 MYRP are represented in this docket at the level filed in the Company's July fuel update[1] as discussed in the Company's August 11, 2019 Compliance Filing in Docket No. E999/CI-03-802 (Order pending).
3. Expenses that have jurisdiction-specific regulatory accounting treatment follow that treatment. For example:
    a. The Company amortizes nuclear fueling outage costs over the periods between outages. These costs should follow the Company's budget; and
    b. Expenses related to the Company's pension and benefit costs have several regulatory adjustments based on the outcome of the Company's recent rate cases.

[1] Company's July 31, 2019 Reply Comments, Docket No. E002/AA-19-293.

4. Secondary calculations necessary for a full cost of service study are based on the results of the above items.
   a. Cash Working Capital balance related to the revenues and expenses developed above
   b. Deferred Tax Asset balance and deferred tax expense related to a Net Operating Loss calculation
   c. Change in debt interest expense related to the budgeted change in debt costs and the budget of rate base.

B. Case Drivers

Q. HAVE YOU PREPARED A COMPARISON OF THE COSTS IN THE MYRP FORECAST TO CURRENT RATES RESULTING FROM THE 2016-2019 MYRP?

A. Yes. I provide an explanation of the detailed case drivers of the deficiency using a comparison of the 2020 test year (including rider roll-ins) with the base rates in effect in 2019 as a result of the MYRP in our last case, Docket No. E002/GR-15-826 (the 2016-2019 MYRP).[2] My analysis also includes a comparison of years two (2021) and three (2022) of the MYRP. My analysis differs from the Direct Testimony analyses of the Company's business area witnesses, who primarily discuss costs and cost changes in terms of actual costs and budgets (not revenue deficiencies). Therefore, my discussion of key cost drivers reflects dollar values that are, in large part, different from their

[2] The 2016-2019 MYRP was based on a settlement that included an illustrative rate base, plus true-ups during the MYRP period for sales forecast, property tax expense, and capital-related revenue requirements. In addition, the cost of service was updated to reflect the implications of the Tax Cuts and Jobs Act (TCJA) as a result of the Commission's findings in Docket No. E, G999/CI-17-895. Therefore, our comparison of drivers compares the base rates in effect in 2019 to the 2020 test year.

discussions. In addition, I discuss these drivers at a high level, and defer to the business area witnesses to provide more detail around the activities and changes giving rise to these drivers.

Q. HAVE YOU PREPARED A SCHEDULE IDENTIFYING THE CHANGES IN THE MAJOR COST ELEMENTS SINCE THE LAST RATE CASE?

A. Yes. I provide Exhibit___(BCH-1), Schedule 6, Detailed Case Drivers, which provides a Summary of Major Cost Drivers (identification of case drivers for the MYRP Forecast), including details of the categories identified in Table 3 below

Table 3

MYRP Net Incremental Deficiency ($ in millions)

	Increase (Decrease) 2020 TY to 2019 MYRP	Increase (Decrease) 2021 TY to 2020 TY	Increase (Decrease) 2022 TY to 2021 TY	3-Year MYRP
Capital and Capital Related	$292.7	$58.7	$78.8	$430.3
Amortizations	5.4	(0.0)	(2.0)	3.5
Taxes	(203.3)	11.2	25.3	(166.9)
Operating Expense	(76.9)	50.8	14.5	(11.6)
Other Margin Impacts*	183.4	25.7	1.7	210.8
Total Net Incremental Deficiency	**$201.4**	**$146.4**	**$118.3**	**$466.1**

*Includes settlement Other Revenue credit (revenue requirement reduction) from the 2016-2019 MYRP

In addition to the discussion in this Section, support for our proposed increase in rates for the 2020 test year is provided in the Direct Testimonies of the Company's business area witnesses and the Direct Testimony of Company witness Mr. Gregory J. Robinson.

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

A. Table 4 below compares the MYRP Forecast revenue requirements with the comparable revenue requirements for the 2019 MYRP, by category, for capital plant related costs as shown on Schedule 6, Detailed Case Drivers.

Table 4

Capital and Capital Related Cost Changes ($ in millions)

	Increase (Decrease) 2020 TY to 2019 MYRP	Increase (Decrease) 2021 TY to 2020 TY	Increase (Decrease) 2022 TY to 2021 TY	3-Year MYRP
Nuclear	$55.2	$3.0	$4.9	$63.1
Steam	(18.3)	2.6	4.4	(11.4)
Wind	77.0	4.6	(1.1)	80.5
All Other Production	2.9	3.8	2.6	9.3
Transmission	60.8	1.3	9.5	71.6
Distribution	22.8	19.9	32.2	74.9
General and Intangible	18.8	11.8	11.9	42.6
DTA (Federal Credits & NOL)	5.8	9.2	11.5	26.5
Other Rate Base	1.0	0.0	(0.8)	0.2
Cost of Capital	66.8	2.4	3.7	72.9
TOTAL Capital and Capital Related	$292.7	$58.7	$78.8	$430.3

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

A. The MYRP Forecast revenue requirements include a $63.1 million increase in Nuclear. This increase is due to capital investments for Nuclear Fuel, Dry Cask Storage, Mandated Compliance, Reliability and Improvements in the MYRP Forecast as well as incremental additions during the last MYRP period. Additional information regarding nuclear projects is discussed in the Direct Testimony of Company witness Mr. Timothy J. O'Connor.

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

A. The MYRP Forecast revenue requirements include an $80.5 million increase to Wind. This increase is due to capital investments for Blazing Star I wind farm, Foxtail wind farm and Lake Benton wind farm as well as a roll-in of Courtenay Wind Farm. Additional information regarding wind projects are discussed in the Direct Testimony of Company witness Mr. Randy A. Capra.

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

A. The MYRP Forecast revenue requirements include a $71.6 million increase to Transmission. This increase is due to a roll-in of large transmission capital projects, particularly the CapX2020 projects from the Transmission Cost Recover Rider TCR). Additional information regarding transmission projects are discussed in the Direct Testimony of Company witness Mr. Ian R. Benson.

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

A. The MYRP Forecast revenue requirements include a $74.9 million increase to Distribution. 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 overhead tap lines, as well as costs associated with the Company's Advanced Grid Intelligence and Security (AGIS) initiative. This increase is also due to capacity investment for greater reliability and required relocation projects stemming from an increased number of road construction projects. Additional information regarding distribution projects are discussed in the Direct Testimony of Company witness Ms. Kelly A. Bloch.

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

A. The MYRP Forecast revenue requirements include a $42.6 million increase to General & Intangible. This increase is due to capital investments relating to replacing aging technology, addressing evolving cyber security threats and requirements, enhancing capabilities, enhancing the customer experience, addressing emergent demands, and the AGIS initiative. Additional information regarding general and intangible projects is discussed in the Direct Testimony of Company witness Mr. David C. Harkness.

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN COST OF CAPITAL.

A. The MYRP Forecast revenue requirements include a $72.9 million increase related to changes in cost of capital. The change in cost of capital is due to a requested 10.2 percent return on equity (ROE), partially offset by a decrease in the cost of long-term debt. Company witness Ms. Sarah Soong describes the capital structure and costs of debt in her Direct Testimony. Company witness Mr. John J. Reed of Concentric Energy Advisors, Inc. discusses the ROE.

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN AMORTIZATIONS.

A. The MYRP Forecast revenue requirements include a small ($3.5 million) increase related to amortizations. This increase is due to new amortizations for Aurora Deferral (discussed in adjustment 15 below) and Net Operating Loss (NOL) Tax Reform Regulatory Amortization (discussed in adjustment 17 below), as well as an increase in Rate Case Expense amortization.

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN TAXES.

A. The MYRP Forecast revenue requirements include a $166.9 million decrease to taxes. This decrease is due to the impacts of TCJA, increased Production Tax Credits (PTC) associated with new wind farms, and a decrease in property taxes. The decrease related to the TCJA is currently being refunded to customers in base rates effective June 1, 2019 as a result of the Commission decision in Docket No. E,G999/CI-17-895. Additional information regarding property taxes is discussed in the Direct Testimony of Company witness Mr. Christopher A. Arend.

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

A. Table 5 below compares the MYRP Forecast revenue requirements with the comparable revenue requirements for the 2019 MYRP, by category, for operating expenses as shown on Schedule 6, Detailed Case Drivers.

Table 5

O&M Cost Changes ($ in millions)

	Increase (Decrease) 2020 TY to 2019 MYRP	Increase (Decrease) 2021 TY to 2020 TY	Increase (Decrease) 2022 TY to 2021 TY	3-Year MYRP
Nuclear	($60.3)	$6.9	$2.3	($51.1)
Steam	(36.3)	3.2	(6.2)	(39.3)
Wind	7.1	1.8	3.8	12.7
Purchased Demand	2.3	4.8	7.7	14.8
All Other Production	7.7	7.1	1.6	16.4
Transmission	(1.7)	(1.6)	0.1	(3.1)
Transmission Interchange	(22.9)	5.4	7.2	(10.4)
Distribution	3.1	17.9	(5.1)	15.9
Regional Markets	3.3	0.0	0.1	3.4
Customer Accounting / Info / Service	(1.7)	(0.0)	(5.0)	(6.7)
A&G	22.5	5.3	8.0	35.9
TOTAL O&M	($76.9)	$50.8	$14.5	($11.6)

Q. WHAT ARE THE REASONS FOR THE DECREASE IN NUCLEAR OPERATIONS OPERATING EXPENSE?

A. The MYRP Forecast revenue requirements include a $51.1 million decrease in nuclear operating expenses. This decrease is due to reductions in contractor costs and materials as several major initiatives have ended, as well as an overall reduction in outage costs. Additional information regarding nuclear operating expenses is discussed in the Direct Testimony of Company witness Mr. Timothy J. O'Connor.

Q. WHAT ARE THE REASONS FOR THE DECREASE IN STEAM OPERATING EXPENSE?

A. The MYRP Forecast revenue requirements include a $39.3 million decrease in steam operating expenses. This decrease is due to a reduction in overhaul costs, elimination of biomass plants, and labor attrition due to planned retirements. Additional information regarding steam operating expenses is discussed in the Direct Testimony of Mr. Capra.

Q. WHAT ARE THE REASONS FOR THE INCREASE IN ADMINISTRATIVE AND GENERAL (A&G) OPERATING EXPENSE?

A. The MYRP Forecast revenue requirements include a $35.9 million increase in A&G operating expenses. This increase is due to increased investments in Business Systems and Enterprise Security related to the Company's additional investments in AGIS and the customer experience, software licensing cost increases, and networking costs. Additionally, the Company's insurance costs have decreased. Additional information regarding Business Systems O&M is discussed in the Direct Testimony of Mr. Harkness. Additional information regarding insurance costs is provided by Company witness Mr. Robert L. Miller.

Q. PLEASE DESCRIBE HOW CHANGES IN SALES RELATE TO THE RATE INCREASE.

A. As discussed by Company witness Ms. Jannell E. Marks, actual sales have declined from 2016 levels and are expected to continue to decline through 2022. Ms. Marks explains that the projected decrease is a result of declining Residential and Commercial and Industrial sales. Consequently, the Company's retail revenues are also expected to decrease, increasing the 2020 revenue deficiency.

Q. ARE THERE ANY OTHER MARGIN ITEMS WITH A SIGNIFICANT IMPACT ON THE 2020 REVENUE DEFICIENCY?

A. Yes. As discussed above with respect to taxes, the impacts of the TCJA are currently being refunded to customers in base rates effective June 1, 2019, which is driving a decrease in revenue compared to the 2019 MYRP. This is partially offset by the 2016-2019 MYRP rate case settlement impacts and interchange revenue credits.

Q. ARE THE FUNCTIONAL CLASS CATEGORIES OF OPERATING EXPENSE COMPARABLE BETWEEN THE 2020 TEST YEAR AND DOCKET NO. E002/GR-15-826 2019 PLAN YEAR?

A. Yes. Budget amounts for both periods conform to the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts. To better show cost drivers, especially as they relate to operating margins, some reclassifications are made in the cost driver analysis from the Jurisdictional Cost of Service Study.

Q. DID YOU INCLUDE COMPARISONS OF THE CHANGE IN THE FUEL AND PURCHASED ENERGY EXPENSE AS PART OF THE O&M EXPENSE ANALYSIS?

A. No. Although the cost of fuel and purchased energy are considered to be an operating expense, recovery occurs through the Company's separate fuel clause adjustment (FCA) mechanism and true-up process. I provide a reconciliation of fuel costs and revenues in Exhibit___(BCH-1), Schedule 21, Fuel Reconciliation.

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.

A. Data Provided and Selection of the Test Year

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

A. In this section, I will:

- identify the supporting financial information and related fiscal periods that we are providing in connection with the MYRP Forecast; and
- demonstrate that the supporting financial information and related fiscal periods that we are presenting provide appropriate information and facilitate review of our MYRP Forecast.

1) Overview

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

A. Following the Commission's rules, financial data is provided for 2018 (the most recent fiscal year), 2019 (the projected fiscal year), and 2020 (the test year). In addition, we provide financial data to support the MYRP Forecast.

The most recent fiscal year (calendar year 2018) reflects the Company's actual financial results. For the projected fiscal year 2019, actual financial results through June 2019 are provided as rate base data, operating expenses and revenues. Forecast projections are provided for the remainder of 2019.

The MYRP Forecast reflects the Company's most recent available budget data.

All fiscal periods provided in this testimony are adjusted for traditional regulatory adjustments (e.g., charitable donations, etc.).

I also provide schedules showing: the actual unadjusted average rate base consisting of the same rate base components; unadjusted operating income; overall rate of return; the calculation of required income; and the income deficiency and revenue requirements for the most recent fiscal year (2018), the projected fiscal year (2019), and the MYRP Forecast. Separate rate base and income statement bridge schedules for the MYRP Forecast that identify test period adjustments are provided with my testimony.

2) MYRP Forecast

Q. WHAT WAS THE BASE SOURCE FOR THE PROPOSED MYRP FORECAST COSTS?

A. Calendar year 2020 was selected as the test year for this filing using Xcel Energy's most recent available budget data for the first year of the budget cycle. Use of a fully projected calendar test year (2020) is consistent with longstanding practice and precedent in the Company's rate cases before the Commission.

The 2021 and 2022 plan years reflect year two and three from the most recent available budget information, of which the 2020 test year is year one. Unlike our last rate case, our plan year O&M is based on the budget for those years as opposed to using escalations from the test year budget. Using the same budget vintage for the test year and plan years allows for a consistent MYRP Forecast.

The 2020-2022 Budget is supported in Mr. Robinson's Direct Testimony and provided in Volumes 5 (Budget Summary and Documentation) and 6 (Budget Documentation) of the Application.

Q. DOES THE COMPANY ANTICIPATE UPDATING SOME OF ITS INFORMATION IN REBUTTAL TESTIMONY?

A. Yes. Consistent with prior cases, we will update certain costs to incorporate updated information. More specifically, as in our last rate case, we will review the following and update in this case as appropriate.

- Cost of capital to reflect the most currently available data;
- Current customer count and sales information and expected trends that might indicate that adjustments to the sales and customer counts forecast are needed;
- Assumptions used for calculating Qualified Pension, FAS 106 retiree medical and FAS 112 post-employment benefits expense based on information as of December 31, 2019;
- O&M active health care may be updated to reflect actual 2019 active medical and pharmacy claims;
- Property tax forecasts based upon property tax data that will become available during 2020.

Q. IN ADDITION TO THE UPDATES LISTED ABOVE THAT WILL REFLECT THE MOST CURRENT AVAILABLE DATA IN THE TEST YEAR, DO YOU ANTICIPATE ANY OTHER ADJUSTMENTS IN REBUTTAL TESTIMONY?

A. Yes. As discussed in further detail in Section VII, Annual Adjustments to the MYRP Forecast, Part F. Rebuttal Adjustments, of my testimony, we have identified certain adjustments that may be necessary. We have made these known adjustments for purposes of interim rates, and we will make adjustments for final rates in our Rebuttal Testimony.

3) Supporting Information and the 2020 Projected Test Year

Q. WHY DOES THE COMPANY USE 2018 AS ITS MOST RECENT FISCAL YEAR INSTEAD OF 2019?

A. Minn. R. 7825.3100, Subp. 10 provides the following definition:

> Most recent fiscal year" is the *utility's prior fiscal year [here, 2018]* *__unless__* notice of a change in rates is filed with the commission within the last three months of the current fiscal year *and at least nine months of historical data is available for presentation of current fiscal year financial information*, in which case the most recent fiscal year is deemed to be the current fiscal year [here 2019]. (Emphasis added.)

In this proceeding, the Company's most recent fiscal year is 2018, and its current fiscal year is 2019. The Company's "most recent fiscal year" is also 2018, as the two exceptions to the rule that would instead convert 2019 into the most recent fiscal year are not fulfilled here. While the Company is filing this rate case within the last three months of 2019, nine months of actual 2019 data is "not available for presentation." Since that requirement cannot be met, the plain language of the Rule directs the Company to use 2018 as the most recent fiscal year, consistent with the Company's long standing approach.

Nothing in the Rule requires the Company to delay its filing until additional 2019 data becomes available or to accelerate the availability of the actual data to include nine months of actual data with the filing. Rather, Minn. R. 7825.3100, Subp. 10 requires the Company to treat 2018 as the prior fiscal year and Minn. R. 7825.3100, Subp. 12 requires that we treat 2019 as the projected fiscal year.

Q. IS THIS APPROACH ALSO CONSISTENT WITH THE COMPANY'S PAST PRACTICES THAT HAVE BEEN ACCEPTED BY THE COMMISSION?

A. Yes. In our rate case in Docket E002/GR-12-961, the Administrative Law Judge (ALJ) found that the Company's practice was consistent with its filings in past rate cases, and was in compliance with Commission rules. Therefore, the ALJ supported,[3] and the Commission adopted, the Company's use of a fully projected test year. Most recently, we utilized actual 2014 data as the "most recent fiscal year" data in Docket No. E002/GR-15-826, as 2015 actual data was not available for presentation at the time of that filing. There was no issue with that approach in that case.[4]

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[3] ALJ Report Findings 866-873 in Docket No. E002/GR-12-961 (July 3, 2013).

[4] We recently noted that in one case, the Commission issued a rule variance in order to permit a utility to utilize the last full calendar year (2020 data) as the "most recent fiscal year" for a rate case filed in the last two months of 2017. *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota,* ORDER ACCEPTING FILING, SUSPENDING RATES, EXTENDING TIMELINE, AND VARYING RULE, Docket No. G011/GR-15-736 (Dec. 5, 2017). We do not believe a variance is necessary here, just as it has not been necessary in prior NSPM rate cases, because utilizing 2018 data is consistent with the Minnesota Rule under the circumstances of this filing. But if the

Q. DOES THE COMPANY'S PRACTICE RESULT IN LESS INFORMATION BEING INCLUDED IN THE FILING?

A. No. The Company filed information for 2018 (the most recent fiscal year), 2019 (the projected year), the unadjusted 2020 year, the adjusted 2020 test year, and the 2021-2022 plan years. Definitions and financial schedules related to 2018 actual and 2019 projections are included in the following locations.

- Volume 3, Required Information, Section II:
  - Tab 2, Jurisdictional Financial Summary Schedules, Schedule A-1
  - Tab 3, Rate Base Schedules, Section A, Schedule A-1
  - Tab 3, Rate Base Schedules, Section B, Schedule B-2
  - Tab 3, Rate Base Schedules, Section E, Schedule E, Page 2
  - Tab 4, Operating Income Schedules, Section A, Schedule A-1
  - Tab 4, Operating Income Schedules, Section B, Schedule B-1
  - Tab 4, Operating Income Schedules, Section C, Schedules C-1 and C-3
  - Tab 4, Operating Income Schedules, Section F, Schedule F, Page 2
  - Tab 5, Rate of Return Cost of Capital Schedules, Sections A-D;
- Exhibit___(BCH-1), Schedule 7, Comparison of Detailed Rate Base Components;

Commission determines that a variance is necessary, the Company requests a variance under Minn. R. 7829.3200, because (i) the Company began preparing this rate case filing several months before the requisite data was available for 2019, and it would be an excessive burden on the utility to wait to file the case or refile the case when 2019 data is available (and would not align with a calendar year test year); (ii) granting the variance would not adversely affect the public interest, because NSPM has used this approach in the past with the same extensive data, and it has resulted in just and reasonable rates; and (iii) granting the variance would not conflict with standards imposed by law.

- Exhibit___(BCH-1), Schedule 8, Comparison of Detailed Income Statement Components.

B. Jurisdictional Cost of Service Study

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

A. In this section, I will explain the jurisdictional cost of service studies that we prepared for the MYRP Forecast.

Q. PLEASE DESCRIBE THE COMPONENTS OF THE JURISDICTIONAL COST OF SERVICE STUDY FOR THE MYRP Forecast.

A. A summary of the jurisdictional cost of service study for the MYRP Forecast is provided in Schedule 2, Summary of Revenue Requirements. The complete jurisdictional cost of service study for the MYRP Forecast are provided in Schedules 3, Cost of Service Study Summary, and in Volume 4 (MYRP Workpapers) of this filing and include 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 Minnesota 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.

Q. PLEASE DESCRIBE THE JURISDICTIONAL COST OF SERVICE SUMMARY SCHEDULES.

A. The jurisdictional cost of service summary for each year of the MYRP Forecast is included as Schedule 3, Cost of Service Study Summary:

- The Rate Base Summary for Total Company electric operations and the Minnesota jurisdiction is shown on Page 1. It provides the assumed capital structure, including the earned overall rate of return on rate base and the earned ROE. The Rate Base Summary references a calculation of cash working capital, which is detailed in Exhibit ___(BCH-1), Schedule 4 (Cash Working Capital), and Volume 4, Section P10, Cash Working Capital.
- An Income Statement for Total Company electric operations and the Minnesota jurisdiction is shown on Page 2 and Page 3. The income statement shows the determination of total operating income at present authorized retail rates. The Income Statement references calculations for federal and state income taxes, which are detailed on Page 3.
- The Revenue Requirement and Return Summary for Total Company electric operations and the Minnesota jurisdiction is shown on Page 4. It shows the revenue deficiency that needs to be recovered to enable the Minnesota jurisdiction electric operations to earn the requested rate of return on equity (ROE) and the total revenue requirements and the percent of increase that would result by increasing retail billing rates by the amount of the revenue deficiency.

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

A. Yes. The revenue conversion factor calculation is included in Volume 3, Tab B of the Other Supplemental Information; and composite income tax rates are included in Volume 3, Tab C, Schedule C-5, of the Operating Income Schedules.

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

A. The amount of interest deducted for income tax purposes is the weighted cost of debt capital multiplied by the average rate base. This is sometimes called "interest synchronization." The MYRP calculation for the interest synchronization is provided in Schedule 3, Cost of Service Summary, line 110.

Q. WHICH SCHEDULES IN YOUR EXHIBIT ARE RELATED TO RATE BASE?

A. I have provided three schedules related to rate base: Schedule 7, Comparison of Detailed Rate Base Components; Exhibit___(BCH-1) Schedules 10a-10c, 2020-2022 Rate Base Adjustment Schedule; and Exhibit___(BCH-1) Schedule 9, Rate Base, CWIP and ADIT Summary. I discuss these schedules in Section IV, Rate Base and Section VII, Annual Adjustments to the Test Year. Additional comparative rate base schedules are provided in Volume 3, Required Information.

Q. WHICH SCHEDULES IN YOUR EXHIBIT ARE RELATED TO THE INCOME STATEMENT?

A. I have provided two schedules related to the income statement: Schedule 8, Comparison of Detailed Income Statement Components, and Exhibit___(RAC-1), Schedules 11a-11c, 2020-2022 Income Statement Adjustment Schedule. I discuss these schedules in Section V, Income Statement and Section VII, Annual Adjustments to the Test Year. Additional comparative income statement schedules are provided in Volume 3, Required Information.

IV. RATE BASE

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

A. In this section of my testimony, I support the reasonableness of the Company's projected 2020-2022 MYRP rate base and identify and explain how the components of the rate base were determined. I begin by providing the overall rate base calculation and identify its components, then walk through each of the MYRP Forecast components of rate base in turn.

Q. IS THE COMPANY'S PROJECTED 2020 TEST YEAR RATE BASE REASONABLE FOR PURPOSES OF DETERMINING FINAL RATES IN THIS PROCEEDING?

A. Yes. The projected 2020-2022 MYRP rate base for the Company's Minnesota jurisdiction electric operations was developed on sound ratemaking principles in a manner similar to prior Company electric rate cases.

Q. PLEASE EXPLAIN WHAT RATE BASE REPRESENTS.

A. Rate base primarily reflects the capital expenditures made by a utility to secure plant, equipment, materials, supplies and other assets necessary for the provision of utility service, reduced by amounts recovered from depreciation and non-investor sources of capital.

Q. PLEASE IDENTIFY THE MAJOR COMPONENTS OF THE PROJECTED 2020-2022 MYRP RATE BASE.

A. The MYRP rate base is generally comprised of the following major items, which I later describe in detail:

- Net Utility Plant,

- Construction Work in Progress,
- Accumulated Deferred Income Taxes,
- Pre-Funded Allowance for Funds Used During Construction (AFUDC), and
- Other Rate Base.

Q. HOW DOES THE COMPANY CALCULATE RATE BASE?

A. The Company's rate base can be expressed using the breakdown on Page 27 of the "Electric Utility Cost Allocation Manual" of the National Association of Regulatory Utility Commissioners (NARUC) as follows:

	Original Average Cost of Electric Plant in Service (Plant)
Less:	Average Accumulated Depreciation Reserve (Reserve)
Less:	Average Accumulated Provision for Deferred Taxes (net of accts 281-283 and 190) (ADIT)
Plus:	Average Construction Work in Progress (CWIP)
Plus:	Average Working Capital (Work Cap)
Equals:	Rate Base

In this case, the calculation is as follows, using the average of the beginning of year (BOY) and end of year (EOY) balances for the test year:

Plant	$19,958,469	(per BCH-1, Schedule 3, Page 1, Line 23)
Reserve	(9,295,420)	(per BCH-1, Schedule 3, Page 1, Line 24)
ADIT	(2,301,002)	(per BCH-1, Schedule 3, Page 1, Line 32)
CWIP	363,989	(per BCH-1, Schedule 3, Page 1, Line 26)
Other Rate Base	260,864	(per BCH-1, Schedule 3, Page 1, Line 42)
Rate Base	$8,986,901	(thousands of dollars)

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

A. Schedule 7, Comparison of Detailed Rate Base, provides a detailed statement of the rate base components. Page 1 provides a comparison of the rate base components for the 2020 test year, to the 2019 plan year used in our most recent rate case. Page 2 provides the rate base components for the MYRP Forecast.

Schedule 9, Rate Base, CWIP and ADIT Summary, Page 1 of 4, shows a detailed average rate base by component for the 2020 test year for the Minnesota jurisdiction and Total Company, before and after making proposed test period adjustments. Page 2 shows the 2021 and 2022 plan year detailed average rate base by component for the Minnesota jurisdiction and Total Company. Page 3 shows the MYRP Forecast average Construction Work in Progress for the Minnesota jurisdiction and Total Company, before and after making proposed test period adjustments. Page 4 shows the MYRP Forecast for accumulated deferred income taxes for the Minnesota jurisdiction and Total Company, before and after making proposed test period adjustments.

Schedules 10a-10c, 2020-2022 Test/Plan Year Rate Base Adjustment Schedules, are a bridge schedule showing the 2020-2022 unadjusted rate base, each proposed rate base adjustment, and the resulting proposed 2020-2022 test/plan year rate base.

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 2020 test year. Such treatment is consistent with the method employed in the most recent Minnesota electric rate case.

Q. WHAT HISTORICAL BASE DID THE COMPANY USE AS A STARTING POINT TO DEVELOP THE PROJECTED NET PLANT BALANCES FOR THE BEGINNING OF THE 2020 TEST YEAR?

A. The historical base used for the beginning of the 2020 test year was the Company's actual net investment (Plant in Service less Accumulated Depreciation) on the Company's books and records as of June 30, 2019 plus the forecast for the remaining months of 2019.

Q. ON WHAT BASIS WERE NET PLANT BALANCES PROJECTED FOR THE END OF THE 2020 TEST YEAR?

A. The 2020 test year ending net plant balances were determined by applying the data contained in the 2020 capital budget to the above-described beginning test year balances, adjusted for retirements, depreciation, salvage and removal costs projected to occur during the 2020 test year.

Q. WHAT WAS THE AVERAGE NET UTILITY PLANT INCLUDED IN THE 2020 TEST YEAR RATE BASE?

A. The average net utility plant included in the 2020 test year rate base is $10.663 billion, as shown on Schedule 7, Comparison of Detailed Rate Base Components. This is comprised of an average plant balance of $19.958 billion as detailed on Schedule 7, minus an average depreciation reserve of $9.295 billion, also shown by component on Schedule 7.

B. Construction Work In Progress

Q. WHAT IS CONSTRUCTION WORK IN PROGRESS (CWIP)?

A. In Minnesota, construction work in progress (CWIP) is included as part of the revenue requirement calculation for base rates. CWIP is the accumulation of construction costs that directly relate to putting a fixed asset into use.

Q. HAS CWIP BEEN INCLUDED IN THE 2020 TEST YEAR RATE BASE?

A. Yes. CWIP is included in rate base with a corresponding offset of AFUDC added to operating income, except where the Company is allowed to earn a current return. The rate base amount reflects a simple average of projected CWIP beginning and ending 2020 test year balances. This is consistent with the method employed in Minnesota and approved by the Commission in the Company's last rate case and matches the use of an average rate base. The CWIP and AFUDC determinations for rate base are discussed in the Direct Testimony of Company witness Ms. Laurie J. Wold.

Q. HOW WERE THE 2020 TEST YEAR BEGINNING AND ENDING CWIP BALANCES DETERMINED?

A. The beginning balance for CWIP was the June 30, 2019 historical balance. The beginning CWIP balance was adjusted to reflect projected construction expenditures, AFUDC, and transfers to Plant in Service during the remainder of 2019 and in 2020 to obtain the beginning and ending 2020 test year CWIP balance. These projections were developed from the Company's 2020 capital budget.

C. Accumulated Deferred Income Taxes

Q. PLEASE DESCRIBE ACCUMULATED DEFERRED INCOME TAXES (ADIT).

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 generally 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 TO ARRIVE AT THE 2020-2022 MYRP RATE BASE?

A. As shown on Schedule 7, Comparison of Detailed Rate Base Components, $2.301 billion was deducted. This amount reflects a simple average of the projected beginning and ending 2020 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. Details related to ADIT are provided in Schedule 9, Rate Base, CWIP and ADIT Summary, on Page 4 of 4.

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

A. The Commission's Order in Docket No. E,G999/CI-17-895 requires that the Company amortize its protected excess ADIT as early as IRS provisions allow (using the Average Rate Assumption Method, or ARAM), and amortize unprotected excess ADIT over ten years. This ADIT is included in the amount shown on Schedule 7, Comparison of Detailed Rate Base Components, Page 1. A summary of the TCJA's effect on the deferred taxes associated with plant assets of a regulated activity is discussed in the Direct Testimony of Ms. Wold. Support for the unprotected excess ADIT can be found in Volume 4 MYRP Workpapers, Section III Rate Base (Plant), Tab P2-3.

D. Pre-Funded AFUDC

Q. WHAT IS PRE-FUNDED AFUDC?

A. In Minnesota, AFUDC is included as part of the revenue requirement calculation for base rates. Specifically, during construction, AFUDC is calculated and included in the CWIP balance and is also included in operating income as an offset to the revenue requirement. AFUDC 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, certain rate riders in Minnesota (*e.g.*, the TCR Rider and the Renewable Energy Standards Rider (RES)) include a current return on CWIP as part of the revenue requirement calculation for the rider. The capital projects associated with those riders do not include the accumulated (pre-funded) AFUDC as part of rate base. Pre-funded AFUDC is the Minnesota jurisdictional amount of AFUDC related to those rate riders.

Q. HOW IS PRE-FUNDED AFUDC TREATED?

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

Q. HOW DOES THE COMPANY ACCOUNT FOR PRE-FUNDED AFUDC?

A. Pre-funded AFUDC is recorded in FERC Account No. 253, Other Deferred Credits, during the construction process as AFUDC is incurred, separated by rate jurisdiction within this FERC account. Pre-funded AFUDC is related to projects recovering a current return on CWIP from customers in Minnesota and wholesale transmission customers who pay our FERC-regulated Midcontinent Independent System Operator (MISO) Attachment O and Schedule 26 rates. Once the associated asset is placed into service, the Pre-Funded AFUDC balance is amortized over the same time period as the associated asset.

Q. HOW HAVE YOU TREATED PRE-FUNDED AFUDC IN THE 2020-2022 MYRP?

A. All Minnesota jurisdictional Pre-funded AFUDC has been directly assigned to the Minnesota jurisdiction, according to the functional class of the associated asset for CWIP, Depreciation Reserve, Plant in Service and ADIT in rate base, and to depreciation and deferred taxes, and AFUDC on the income statement. Accumulated Pre-funded AFUDC is a reduction to rate base, with the amortization of the Pre-funded AFUDC balance being a reduction to depreciation expense. The deferred taxes associated with Pre-funded AFUDC create a deferred tax asset during construction that flows back as the book amortization is recognized. These Pre-funded AFUDC items are at a jurisdictional level; thus the offset is made once the rate base and the income statement are jurisdictionalized. The Pre-funded AFUDC recorded and budgeted associated with our MISO transmission tariff have been allocated to Minnesota, North Dakota and South Dakota jurisdictions based on 12 coincident peak demand. This allocation method is consistent with treatment of the underlying transmission assets and their associated expenses and revenues.

E. Other Rate Base

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

A. Other Rate Base is comprised primarily of Working Capital. It also includes certain unamortized balances that are the result of specific ratemaking amortizations, as discussed below 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 requirement (referred to as Cash Working Capital) is shown separately.

Q. How were 2020-2022 MYRP Materials and Supplies and Fuel Inventory requirements calculated?

A. The Materials and Supplies and Fuel Inventory amounts shown on Schedule 3 Page 1, Cost of Service Study Summary, are based on the 13-month average balances ending June 30, 2019, the most recent data available. The Materials and Supplies average balance included in the MYRP rate base equals $154 million. The MYRP average rate base amount for Fuel Inventory is $66 million.

Q. How were 2020-2022 MYRP Non-Plant Assets and Liabilities determined?

A. These balances as shown on Schedule 3 Page 1, Cost of Service Study Summary represent 2020-2022 estimates 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. The Non-Plant Assets and Liabilities average balance are included on Schedule 3, Cost of Service Study Summary Page 1, Line 37 for each year of the MYRP Forecast.

Q. How were 2020-2022 MYRP Prepayments and Other Working Capital items determined?

A. Prepayments and Other Working Capital, such as customer advances and deposits, are based on the actual 13-month average balances during the period ended June 30, 2019, as a proxy for the 2020-2022 MYRP. Our nuclear outage amortization is also included in Other Working Capital. The average rate base for nuclear outage amortization is based on the average of the beginning of year and end of year balances. The unamortized balances included in this section are based on the amortization schedules as described in Section IV. The Prepayments and Other Working Capital average balances are included on Schedule 3, Cost of Service Study Summary Page 1, Lines 38-40 for each year of the MYRP Forecast.

Q. HOW WERE THE MYRP FORECAST CASH WORKING CAPITAL REQUIREMENTS DETERMINED?

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

Q. WERE THE COMPONENTS OF THE MYRP Forecast CASH WORKING CAPITAL CALCULATED CONSISTENT WITH METHODS USED IN THE LAST RATE CASE?

A. Yes. The MYRP Forecast cash working capital has been calculated consistent with methods accepted in our most recent Minnesota electric rate case.

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 XCEL ENERGY'S LEAD/LAG STUDY BEEN UPDATED SINCE THE LAST ELECTRIC RATE CASE?

A. Yes. The Company has updated the lead/lag study for the calculation of the lead and lag days for all categories through year end 2018, using the methodology for calculating the lead/lag days consistent with the Company's prior electric and gas regulatory filings. The results of the updated lead/lag study for electric operations were incorporated into the Minnesota jurisdiction cash working capital calculations as shown on Schedule 3, Cost of Service Study Summary, Page 1.

Q. WHAT ARE THE MYRP FORECAST CASH WORKING CAPITAL AMOUNTS?

A. The amounts included as reduction in average rate base in the MYRP Forecast are based on the results of our lead lag study prepared consistently with previous rate cases. The resulting Cash Working Capital amounts are as follows:

- 2020 Test Year: ($119.1 million),
- 2021 Plan Year: ($127.0 million),
- 2022 Plan Year: ($140.9 million).

Q. HAS THERE BEEN A CHANGE IN THE TEST-YEAR CASH WORKING CAPITAL AMOUNT SINCE THE LAST RATE CASE?

A. Yes. The $119.1 million reduction in test year Cash Working Capital requirement is an $8.0 million greater reduction than the amount of the reduction in the test year in the last rate case ($111.1 million).

Q. WHAT IS THE SOURCE OF THE CHANGE IN CASH WORKING CAPITAL?

A. The change in Cash Working Capital from the 2016 level is primarily due to the net changes in the average expense lead and revenue lag days between the two periods. Average revenue lag days decreased to 39.66 in 2020 from 41.58 in 2016, meaning the Company's revenues are being collected on average 1.92 days quicker in 2020 than in 2016. Conversely, the Company's average expense lead days decreased to 55.61 in 2020 from 56.34 in 2016, meaning that the Company's cash outlay for paying expenses has been shortened by an average of 0.73 days. Overall, cash inflows from revenue collections exceed the longer time frame for disbursing cash, giving rise to a negative cash working capital balance to be included in rate base.

Q. WHAT IS THE SIGNIFICANCE OF NEGATIVE CASH WORKING CAPITAL?

A. A negative cash working capital indicates that overall revenue collections occur sooner than the date when the associated costs of service are paid. In other words, on average, more cash requirements are being provided by customers and vendors. The negative cash working capital reduces rate base to compensate customers for funds provided to meet cash working capital requirements. It should be noted that changes in the revenues or expenses could cause the cash working capital calculation to be changed. The Company will update the 2020-2022 MYRP COSS accordingly.

V. INCOME STATEMENT

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

A. In this section, I will support the reasonableness of the Company's proposed MYRP Forecast income statements. I begin by providing the overall income statement calculations and identify their components, then walk through each of the MYRP Forecast components of the income statements in turn.

Q. ARE THE COMPANY'S PROPOSED MYRP FORECAST INCOME STATEMENTS REASONABLE FOR DETERMINING FINAL RATES IN THIS PROCEEDING?

A. Yes. The proposed MYRP Forecast income statements for the Company's Minnesota jurisdiction electric operations were developed on sound ratemaking principles in a manner similar to prior Company electric rate cases.

Q. PLEASE IDENTIFY THE MAJOR COMPONENTS OF THE PROJECTED INCOME STATEMENTS.

A. The following are the major components of the MYRP Forecast income statements:

- Revenues,
- Operating and Maintenance Expenses,
- Depreciation Expense,
- Taxes,
- AFUDC, and
- Interchange Agreement.

Q. PLEASE DESCRIBE THE SCHEDULES TO YOUR TESTIMONY THAT ARE RELATED TO THE INCOME STATEMENT.

A. Schedules 11a-11c, 2020-2022 Income Statement Adjustment Schedules, are bridge schedules that show the unadjusted income statement, each proposed income statement adjustment, and the resulting proposed income statement for each year of the MYRP Forecast. Schedules 11a-11c also include the revenue deficiency amount for each item included in this schedule.

Schedule 8, Comparison of Detailed Income Statement Components, provides a detailed statement of the income statement components. Page 1 provides a comparison of income statement components for the Company's last rate case filing to the 2020 test year assuming final rates. Page 2 provides the income statement components for the MYRP Forecast.

A. Revenues

Q. HOW DOES THE COMPANY PRESENT ITS PROJECTED SALES FOR THE MYRP FORECAST CONSIDERED?

A. The MYRP Forecast sales volumes are supported by the Direct Testimony of Ms. Marks. Ms. Marks discusses the bases for the Company's sales forecasts, including the use of normal weather to develop the Company's projected MYRP sales.

Q. DO RETAIL OPERATING REVENUES REFLECT THE PROJECTED LEVEL OF UNBILLED SALES VOLUMES IN THE MYRP 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 MYRP Forecast includes items such as revenues from sales to other utilities, certain revenues from wholesale trading activities, wholesale transmission revenues, 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 tariffed charges, a representative level was determined and included as part of the revenues in the cost of service study. Other operating revenues also include billings to NSPW under the Interchange Agreement.

Consistent with our previous rate cases, I have included an adjustment to use the three-year average (2017, 2018 and 2019 Bridge) for certain other revenues in the determination of the MYRP Forecast levels of Other Revenues. This adjustment accounts for variability and includes other unbudgeted revenue that the Company receives in an actual year that cannot be anticipated for budget purposes. I discuss this revenue adjustment and other adjustments to revenues in more detail in Section VII, Annual Adjustments to the MYRP Forecast.

Q. HAVE REVENUES AND EXPENSES ASSOCIATED WITH NSPM'S NON-REGULATED BUSINESS ACTIVITIES BEEN EXCLUDED FROM THE MYRP FORECAST COST OF SERVICE?

A. Yes, we have excluded the revenues and expenses associated with Commission-approved non-regulated business activities (i.e. customer-owned street lighting maintenance and Sherco steam sales to Liberty Paper) from the MYRP cost of service. Because these activities are recorded in below the line accounts, they were not included in the MYRP Forecast.

Q. HOW ARE REVENUES AND EXPENSES RELATED TO THE MISO SCHEDULES TREATED IN RATES?

A. Both revenues and expenses related to the MISO schedules are included in the determination of retail rates through either base rates, the FCA or the TCR Rider. Base rate recovery, for example, includes both the revenues received from MISO and the expense billings from MISO for Schedules 1 (Scheduling, System Control and Dispatch Service) and 2 (Reactive Supply and Voltage). The FCA, for example, includes Schedule 3 (Regulating Reserve). The TCR Rider includes recovery of Schedule 26 (Network Upgrade from Transmission Expansion Plan) and 26-A (Multi-Value Project Usage Rate) revenues and expenses. The TCR Rider also includes, for capital projects not regionally shared, an Open Access Transmission Tariff (OATT) Revenue Credit to estimate the revenue that will be collected for the project from wholesale transmission customers. The treatment of revenues and expenses related to the MISO schedules is consistent with their treatment in prior rate cases.

Q. WHAT ARE WHOLESALE MARGINS?

A. There are two categories of transactions that generate wholesale margins (revenues less costs): asset based transactions; and non-asset based transactions. Asset based transactions are comprised of short-term sales of excess energy or capacity from Company-owned generation assets or power purchase agreements (PPAs) executed to serve our native load customers. The Company executes these asset based transactions through bilateral agreements with specific wholesale customers and through sales directly into the MISO energy market. Sales into the MISO market account for the bulk of these transactions.

Non-asset based transactions are wholesale trading transactions undertaken to obtain margins from purchases and sales of energy or capacity unrelated to meeting the energy needs of our native load customers. The only transactions that qualify as non-asset based transactions are third-party supplied electricity or financial transactions that are not purchased to meet the needs of our retail customers and that are then resold to other utilities or market participants.

Q HOW HAVE ASSET BASED MARGINS BEEN TREATED IN PRIOR RATE CASES?

A. Because asset based margins are created by selling energy or capacity from generating facilities or PPAs paid for by customers, all asset based margins have been credited to customers. In each of our last three rate cases, the Commission approved passing the sales margins through to customers using the FCA.

Q. IS THE COMPANY RECOMMENDING ANY CHANGE TO THE TREATMENT OF ASSET BASED MARGINS?

A. No. The Company recommends the same treatment of crediting asset based energy sales margins to customers through the FCA going forward, which is reflected in an adjustment discussed in Section VII, Annual Adjustments to the MYRP Forecast.

Q. HOW HAVE NON-ASSET BASED MARGINS BEEN ADDRESSED IN PRIOR CASES?

A. In our last two rate cases: (i) 100 percent of the non-asset based trading margins were retained by the Company; and (ii) 100 percent of the fully allocated O&M costs and IT system-related costs associated with non-asset based trading margins were excluded from the test year and, thus, resulted in a decrease in test year operating expenses.

Q. HAS THE COMPANY CONDUCTED INCREMENTAL AND FULLY ALLOCATED COST STUDIES OF NON-ASSET BASED TRADING?

A. No. At one time, the Company advocated a contribution from non-asset based margins based on incremental cost. As a consequence, the Commission ordered the Company to prepare incremental and fully allocated cost studies to support the Company's position. However, the Company is already required to exclude the fully allocated non-asset based trading costs from test year expense, and because we requested the elimination of an incremental cost study in our previous electric rate case with no comment or objection, no incremental cost study was prepared for this proceeding.

Q. IS THE COMPANY RECOMMENDING ANY CHANGE TO THE TREATMENT OF NON-ASSET BASED MARGINS?

A. The only change in the treatment of non-asset based margins is the elimination of the incremental cost study. Consistent with past Commission decisions, we are making an adjustment to exclude costs equal to the fully allocated cost of non-asset based trading, as further explained in Volume 4 MYRP Workpapers, Section VIII Adjustments, Tab A30.

Q. UNDER THE COMPANY'S PROPOSALS FOR ASSET BASED MARGINS AND NON-ASSET BASE MARGINS, IS IT NECESSARY TO MAKE ANY TEST OR PLAN YEAR ADJUSTMENTS?

A. Yes, we make three adjustments. First, with respect to asset-based energy sales margins, the 2020-2022 budget base data includes all fuel costs and trading revenues. However, all asset-based energy sales margins are passed through to the customers in the FCA. The fuel clause revenue included in retail revenue does not include asset-based margins. Therefore, the Asset Margin Sharing adjustment also excludes asset-based energy sales revenues and expenses from the MYRP Forecast.

Second, the 2020-2022 budget base data does not reserve the non-asset based trading margin for the shareholders. Therefore, the Non-Asset Margin Retention adjustment removes these revenues and expenses from the test and plan years.

Lastly, the Non-Asset Trading O&M Credit adjustment credits the operating expenses in the income statement for the fully allocated O&M and IT-related costs of non-asset based trading activity. The MYRP Forecast adjustments are also included in Section VII, Annual Adjustments to the MYRP Forecast.

B. Operating and Maintenance Expenses

Q. HOW DOES THE COMPANY CALCULATE OPERATING EXPENSES?

A. The Company's operating expenses can be expressed using the breakdown on Pages 30-31 of the "Electric Utility Cost Allocation Manual" of the National Association of Regulatory Utility Commissioners (NARUC) as follows:

Operation and Maintenance Expense (including fuel) (Operating Exp)
+ Depreciation Expense (Depreciation)
+ Miscellaneous Amortization Expense (Amortization)
+ Taxes other than Income Taxes (Other Taxes)
+ Income Taxes (Income Tax)
= Total Expenses

In this case, the calculation is provided in Table 6 below:

Table 6

Operating Expenses

	Item	2020 Test Year Amount ($000s)	2021 Plan Year Amount ($000s)	2022 Plan Year Amount ($000s)	Exhibit__ (BCH-1), Sch. 3 Reference
	Operating Expense	$ 2,313,678	$ 2,365,673	$ 2,381,602	Page 2, Line 74
plus	Depreciation	683,392	719,524	760,859	Page 2, Line 76
plus	Amortization	43,948	43,475	44,757	Page 2, Line 77
plus	Other Taxes	134,178	38,204	33,630	Page 2, Line 88
plus	Income Tax	(6,184)	59,576	56,478	Page 3, Line 134
equals	Total Expense	$ 3,169,012	$ 3,226,453	$ 3,277,326	Page 3, Line 138

Q. WHAT ARE THE PRINCIPLE O&M EXPENSE CATEGORIES?

A. The principle expense categories are:

- Fuel & Purchased Energy,
- Power Production,
- Regional Markets,
- Transmission Interchange,
- Transmission,
- Distribution,
- Customer Accounting,
- Customer Service & Information,
- Sales, Economic Development and Other,
- Administrative and General.

Q. HOW ARE FUEL AND PURCHASED ENERGY COSTS TREATED?

A. These fuel and purchased energy costs are collected through the FCA. Those costs are fully offset by revenues from the FCA. Therefore, these costs have no impact on the 2020 test year revenue deficiency.

Q. HAS THIS CHANGED SINCE THE LAST RATE CASE?

A. Yes, while the level of fuel revenues and expenses are consistent with the last rate case, the Company is no longer providing a base cost of energy filing with this rate case, consistent with the Commission's October 17, 2019 determination in Docket No. E999/CI-03-802. In recognition of that proceeding we have provided financial schedules that reflect a cost of service with and without fuel revenues and expenses. Where comparisons are made with prior years we continue to present those financial schedules with fuel revenues and expenses to allow comparison.

Q. WHAT ARE POWER PRODUCTION COSTS AND HOW ARE THEY DETERMINED?

A. Power production costs are primarily the costs of operating our generating facilities. These costs are budgeted through development of a production budget prepared to serve the combined energy and demand requirements of the NSP System (used 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 costs. Please see the Direct Testimony of Mr. Capra for additional details.

Q. HOW DOES XCEL ENERGY DEVELOP ITS TEST YEAR TRANSMISSION EXPENSE?

A. Transmission expenses are the O&M costs associated with operating and maintaining our system transmission facilities. These costs are budgeted through development of a transmission budget prepared to serve the NSP System (*i.e.*, for both NSPM and NSPW). These costs and their development are detailed in Mr. Benson's Direct Testimony.

Q. HOW DOES XCEL ENERGY DEVELOP ITS TEST YEAR DISTRIBUTION EXPENSE?

A. Distribution expenses are the O&M costs associated with operating and maintaining our Minnesota distribution facilities. These costs are developed through a distribution budget prepared for both the NSPM electric and gas utilities. These costs and their development are detailed in the Direct Testimony of Ms. Bloch. The allocation of these costs to the electric utility and then to the Minnesota jurisdiction is addressed in Section VI of my Direct Testimony.

Q. HOW DOES XCEL ENERGY DEVELOP ITS TEST YEAR CUSTOMER SERVICE EXPENSE?

A Customer Service O&M cost is associated with providing meter reading, billing, credit and collections, bad debt expense, contact center and operational support services. These costs are developed through the Customer Care budget prepared for both the NSPM electric and gas utilities. These costs and their development are detailed in the Direct Testimony of Company witness Mr. Christopher C. Cardenas. The allocation of these costs to the electric utility and then to the Minnesota jurisdiction is addressed in Section VI of my Direct Testimony. As Mr. Cardenas explains, our bad debt expense is affected by the level of commodity sales (retail sales). Therefore, changes in the sales forecast affect the bad debt expense. As a result of updating the sales forecast after the 2020 budget was developed, a change in the bad debt expense is needed. I discuss that adjustment in Section VII of my Direct Testimony.

Q. WHAT COSTS ARE INCLUDED IN ADMINISTRATIVE AND GENERAL (A&G) EXPENSE?

A. A&G expense includes IT, compensation, office supplies and expenses and consulting services for officers, executives, and other Company employees properly chargeable to utility operations and not chargeable directly to a particular operating function. Also included in A&G expense are property insurance, insurance and other costs related to injury or damage claims made by employees or others, employee pensions and benefits, regulatory expenses, general advertising expense, utility rental expense not properly chargeable directly to a particular operating function and maintenance costs assignable to the customer accounts, sales and A&G functions.

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 made a conscious decision to move all lobbying costs to below the line accounting, FERC account 426.4, Expenditures For Certain Civic, Political and Related Activities. The Company prepares the unadjusted expenses for the test year using queries that restrict the data to only above-the-line accounts (FERC Accounts 500 through 935). Thus, no adjustment to the cost of service for lobbying costs is required, as these below the line amounts are not used in our development of the test year cost of service.[5] We have also excluded the portion of organizational dues associated with lobbying activities. Company witness Mr. Gary J. O'Hara addresses our efforts to identify and remove lobbying expenses in his Direct Testimony.[6]

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[5] As discussed by Company witness Mr. Gary J. O'Hara, the Company discovered that the lobbying labor costs budgeted for State Public Affairs did not align with State Public Affairs' actual forecasted labor costs for purposes of the Company's calculation of the Minnesota cost of service. This misalignment was not discovered until after the cost of service was developed. The Company will make an appropriate adjustment in Rebuttal Testimony.

[6] Charitable contributions, economic development contributions, and Chamber of Commerce dues are other below-the-line expenses that are moved above the line, in part, through adjustments described in Section VII.

C. Depreciation Expense

Q. WHAT IS THE BASIS OF THE DEPRECIATION RATES AND EXPENSE USED IN THE 2020-2022 MYRP?

A. Depreciation expense for the 2020 test year reflects the Company's approved 2019 Average Remaining Life filing (Docket No. E, G002/D-19-161) and the results of the Annual Update of Remaining Lives and Depreciation Rates for Transmission, Distribution and General Accounts (Docket No. E,G002/D-18-523).

Ms. Wold discusses the Company's depreciation expense in her Direct Testimony.

D. Taxes

Q. WHAT TAX EXPENSES ARE INCLUDED IN THE 2020 TEST YEAR INCOME STATEMENT?

A. We have line items for Property; Income Taxes including Deferred Income Tax, Investment Tax Credits and Federal and State Income Tax; and Payroll. The State and Federal income taxes are calculated in Schedule 3, Cost of Service Study Summary for 2020 test year, Page 2 of 4.

Q. HOW ARE PROPERTY TAXES DETERMINED FOR THE JURISDICTION?

A. Property taxes are determined on a NSPM Total Company basis. The functions are then allocated to the Company's regulatory jurisdictions using the demand allocator for electric production and transmission, the gas design day allocator for gas production, and transmission and distribution is direct assigned by state for both electric and gas. Please see Volume 4, Tab P-6, Property Tax for more details.

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. The Company continues to follow the resolution of "Tax Normalization and Allowance for Net Operating Losses" from the last three rate cases, which was reflected in Exhibit 105 in Docket No. E002/GR-10-971. Specifically, the Company will continue 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. The annual reporting process which incorporates actual revenues, deductions and cost of capital will continue to be the vehicle to track the utilization and balances and annually refund any utilization that has not been applied in base rates.

Had this rate treatment not been approved by the Commission, the 2020 test year revenue requirement would be the same. However, if utilization of carried-forward deductions and credits took place outside of a rate case test year, then customers would not receive refunds for the revenue requirement value. Therefore this treatment ensures customers are protected in the event of changes in the utilization of tax deductions and credits.

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 during a time of setup. 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 that first 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 NSPM Electric Utility Minnesota 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 2020 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 rate refund or reduction to base rates.

These balances related to unused credits and deductions are reported in the Company's May 1 Jurisdictional Annual Report, including the May 1, 2019 Jurisdictional Annual Report. Separate detailed reporting and the revenue requirement value associated with any utilization was most recently reported on June 14, 2019. 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 properties. Any change in rider recovery by the Commission will be incorporated in this process.

Q. DO THE DTAS AFFECT THE 2020-2022 MYRP REVENUE REQUIREMENTS?

A. Yes. The Company's 2020-2022 MYRP COSS includes a revenue requirement increase associated with PTCs carried forward from prior periods to the 2020 test year and 2020-2022 MYRP generation of federal tax credits to be carried forward based on the Company's 2020-2022 MYRP COSS. An accounting for the balances carried forward to the 2020 test year COSS, as well as the documented calculations supporting this revenue requirement increase, can be found in Exhibit___(BCH-1), Schedule 20, 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 2020-2022 MYRP 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 NSPM retail electric 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 2020 test year and any additional years considered by the Commission in the Company's multi-year rate proposal, 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. Production Tax Credits (PTCs) are per-kWh tax credits to income for electricity generated using qualified renewable energy resources.

Q. WHAT IS THE LEVEL OF PRODUCTION TAX CREDITS INCLUDED IN THE STATE AND FEDERAL INCOME TAX CALCULATION IN THE 2020 TEST YEAR?

A. As shown on Exhibit___(BCH-1), Schedule 18, Production Tax Credits, the MYRP Forecast assumes PTCs for the Company-owned wind farms as shown in Table 7 below.

Table 7

Production Tax Credits included in MYRP Forecast

(Amount in $000s)	2020	2021	2022
MN Jurisdictional PTC	$106,916	$94,548	$94,414
MN PTC Impact on Revenue Requirement	(150,041)	(132,685)	(132,496)
MN PTC Impact on Rev Req net of I/A	(124,467)	(110,070)	(109,913)

We expect production to begin at additional wind facilities in late in 2020 or 2021. Due to the anticipated in-service date of these projects, the Company is recommending that these projects be recovered through the RES Rider. I provide a discussion later in this Section of my Direct Testimony about how PTCs interact with the deferred tax asset calculations in the 2020 test year.

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE TREATMENT OF PTCS BETWEEN TEST YEARS?

A. In addition to the PTCs included in the RES Rider, the Company continues to recommend that the RES Rider act as a true-up mechanism for the PTCs related to projects already in service and included in base rates as a part of the 2020 test year cost of service. We propose that the difference in the dollar value of actual PTCs generated and the amounts included in the test year be recorded to the RES Tracker account and either returned to, or recovered from, customers through the RES Rider. This approach meets our understanding of the current regulatory treatment for PTCs.

Q. PLEASE EXPLAIN THE EFFECT OF TAX TREATMENT OF PTCS AND THE REQUIRED REVENUE LEVEL NECESSARY TO COVER THE CHANGE IN OPERATING INCOME.

A. PTCs create a direct reduction (credit) to income tax expense causing a corresponding increase to operating income. Every dollar change in operating income needs a revenue conversion factor to be applied to determine the pre-tax revenue level necessary to achieve the operating income change. The revenue conversion factor calculation is included in Volume 3, Tab B of the Other Supplemental Information; and composite income tax rates are included in Volume 3, Tab C, Schedule C-5, of the Operating Income Schedules.

Q. WHAT IS THE REDUCTION IN REVENUE REQUIREMENTS FOR PTCS REFLECTED IN THE 2020 TEST YEAR FINANCIAL STATEMENTS?

A. The State of Minnesota jurisdictional revenue requirement impact of ($106.9 million) of PTCs after applying the 1.403351 revenue conversion factor is ($150.0 million) or ($124.5 million) net of Interchange Agreement billings to NSPW. Support for these calculations is shown on Schedule 18, Production Tax Credits.

E. AFUDC

Q. WHAT IS AFUDC, AND WHAT IS ITS FUNCTION IN THE INCOME STATEMENT?

A. As previously noted, AFUDC is the cost of financing during the period a capital investment is included in CWIP. Once an asset is placed in service, the total cost to construct including accumulated AFUDC is recovered through depreciation expense. Ms. Wold's Direct Testimony discusses the role AFUDC plays in allowing utilities to recover their cost of financing. In the income statement, AFUDC is used to offset expenses, thus increasing total operating income, and reducing the revenue requirement. This provides a direct offset to the return requirement associated with the inclusion of CWIP in rate base. Please see Section IV. Rate Base, for a detailed discussion of the relationship between CWIP and AFUDC and a discussion of Pre-Funded AFUDC.

F. Interchange Agreement

Q. PLEASE DESCRIBE THE INTERCHANGE AGREEMENT BETWEEN THE COMPANY AND NSPW.

A. The Company and NSPW operate a single integrated electric generation and transmission system and a single electrical "local balancing authority area." This integrated NSP System jointly serves the electric customers and loads of the Company and NSPW. However, the specific generators and transmission facilities making up the NSP 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 NSP System between the Company and NSPW.

Q. PLEASE DESCRIBE THE COSTS AND REVENUES 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, 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 the 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 transmission services or 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, which are 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 budgeted 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 MYRP Forecast Interchange Revenue and Interchange Expenses have been calculated using 2020-2022 Company and NSPW budget information. This is consistent with the treatment of Interchange Revenues and Interchange Expenses in our last three rate cases.

Q. PLEASE DESCRIBE THE INTERCHANGE AGREEMENT OFF-SET TREATMENT BEING EMPLOYED IN THE MYRP FORECAST COSS.

A. As discussed earlier, in general, the Interchange Agreement is designed to share system-related production and transmission cost between the two operating companies, NSPM and NSPW. The intent of this sharing is to represent these two company systems as a single joint operation. To equalize the costs across this joint system, each operating company bills the other operating company for their share of the joint costs in general using energy requirements as the basis for variable cost sharing and peak demand as the basis for sharing capital related and other fixed costs.

Q. WHAT SPECIFIC COMPONENTS ARE IMPACTED BY THIS SHARING IN THE 2020 TEST YEAR COSS?

A. The NSPM billings to NSPW for the sharing of NSPM costs appear as other revenues in the MYRP Forecast cost of service. The NSPW billings to NSPM for the sharing of NSPW costs appear as either production or transmission expenses in the MYRP Forecast cost of service. Also, any adjustments being proposed in the case that pertain to production or transmission are developed using the same mechanics.

VI. UTILITY AND JURISDICTIONAL ALLOCATIONS

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

A. In this section I will:

- explain, at a high level, why it is necessary for the Company to allocate costs among its affiliates and between the jurisdictions in which it does business;
- describe the utility and jurisdictional allocations that are used in determining the revenue requirement;
- explain the circumstances of the elimination of the separate Wholesale Jurisdiction, the circumstances that led to the loss of full service wholesale customers, and the effect of those events, including the results of the Company's Wholesale Customer Study.

Q. WHY IS IT NECESSARY TO ASSIGN OR ALLOCATE COSTS BETWEEN NSPM AND ITS AFFILIATES?

A. Whenever services or facilities are shared between NSPM and an affiliate, it is necessary that the appropriate costs related to those services or facilities be assigned or allocated to the appropriate entity. Company witness Ms. Melissa L. Schmidt, in her Direct Testimony, explains the allocations for services and facilities shared between NSPM and an affiliate. The cost assignment and allocation principles are unchanged from those used by the Company in the most recent Minnesota electric rate case. Additional information regarding this process and the reason for selecting a particular allocator is also included in the Cost Assignment and Allocation Manual (CAAM) submitted with this application as Ms. Schmidt's Exhibit___(MLS-1), Schedule 3.

Q. IS IT NECESSARY TO ASSIGN OR ALLOCATE COSTS BETWEEN NSPM'S ELECTRIC AND GAS UTILITIES?

A. Yes. NSPM operates both an electric utility and a gas utility. Therefore, it is necessary that the appropriate costs related to those services or facilities be assigned or allocated to the appropriate utility.

Q. IS IT NECESSARY TO ASSIGN OR ALLOCATE COSTS BETWEEN JURISDICTIONS?

A. Yes. The Company operates in three jurisdictions: Minnesota, North Dakota and South Dakota. Thus, it is necessary to allocate or assign costs appropriately between jurisdictions. Previously, costs were allocated or assigned to four jurisdictions: Minnesota, North Dakota, South Dakota and Wholesale. Beginning in 2014, however, the Company has no full requirements wholesale customers. Therefore, since 2014, costs are allocated between the Company's three retail jurisdictions.

Q. HOW ARE COSTS ASSIGNED AND ALLOCATED?

A. 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 the Minnesota jurisdiction electric utility operations where appropriate or allocated based on cost causation.

Detailed records are maintained on a functional basis (*i.e.* Production, Transmission, Distribution, etc.). 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.

Generally, all production plant is allocated to jurisdiction using the jurisdictional demand allocator, with the exception of wind projects, which are allocated using the jurisdictional energy allocator. In addition, production costs are shared with NSPW under the terms of the Interchange Agreement. The Interchange Agreement tariff approved by FERC specifically requires fixed production assets to be allocated between NSPM and NSPW based on demand.

Fixed production O&M expense is allocated using the jurisdictional demand allocator. In addition, fixed production O&M expense is shared with NSPW under the terms of the Interchange Agreement. The Interchange Agreement requires these costs to be allocated between NSPM and NSPW based on demand.

All variable production O&M expense is allocated to jurisdiction using the jurisdictional energy allocator. In addition, variable production O&M expense is shared with NSPW under the terms of the Interchange Agreement.

The Interchange Agreement requires these costs to be allocated between NSPM and NSPW based on energy.

Ms. Schmidt further explains assignment and allocation of costs in her Direct Testimony.

Q. HOW ARE THESE ALLOCATION FACTORS DEVELOPED?

A. A summary and description of the allocation factors used to allocate expenses and capital items to the Minnesota jurisdictional electric operations income statement and rate base is contained in Volume 3, Required Information, II Required Financial Information, 3E Rate Base Jurisdictional Allocation Factors and 4F Operating Income Jurisdictional Allocation Factors. Plant investments are accounted for in the manner prescribed by the FERC Uniform System of Accounts. Ms. Schmidt also further explains the development of allocation factors in her Direct Testimony.

Q. HOW ARE FUEL AND PURCHASED POWER COSTS ALLOCATED?

A. Fuel and purchased energy costs are allocated to each jurisdiction using the jurisdictional energy allocator. Purchased demand costs are allocated to each jurisdiction using the jurisdictional demand allocator. In addition, fuel and purchased power costs are shared with NSPW under the terms of the Interchange Agreement. The Interchange Agreement requires fuel and purchased energy costs to be allocated between NSPM and NSPW based on energy. Purchased demand costs are allocated between NSPM and NSPW using demand.

Q. HOW ARE COMPENSATION- AND BENEFIT-RELATED RATE CASE ADJUSTMENTS ALLOCATED?

A. Compensation and benefit related rate case adjustments are allocated to jurisdictions using a weighted allocator based on all expenses in FERC 926 Employee Pensions and Benefits. Expenses in FERC 926 were allocated following the Cost Assignment and Allocation Manual (CAAM) submitted with this application as Schedule 3 to Ms. Schmidt's Direct Testimony. An additional allocator was then created by determining each jurisdiction's portion of the Total NSPM expenses. The data used to calculate this allocator can be found in Volume 4 MYRP Workpapers, Section VII Budget Allocators, Tab B-4.

Q. WHAT IS THE WHOLESALE CUSTOMER STUDY?

A. The Wholesale Customer Study shows all wholesale customers being served by the Company (including, but not limited to, full requirements, partial requirements, and market based wholesale customers), types of service being provided to each wholesale customer, costs and revenues associated with each wholesale customer, and a clear showing either that wholesale costs are allocated out of the retail rate case or that the revenues are included in the retail rate case, for all services provided to wholesale customers.

Q. DOES THE WHOLESALE CUSTOMER STUDY EXPLAIN WHY THE COMPANY NO LONGER ALLOCATES COSTS TO A WHOLESALE JURISDICTION?

A. Yes. Exhibit___(BCH-1) Schedule 14, Wholesale Customers Study, explains that all of our partial requirements and energy only wholesale customers are provided services pursuant to bilateral agreements, and also explains the treatment of costs and revenues related to services provided to those customers.

Q. WHAT SERVICES DOES THE COMPANY ANTICIPATE PROVIDING TO PARTIAL REQUIREMENTS WHOLESALE CUSTOMERS DURING THE MYRP FORECAST?

A. During the MYRP Forecast, the Company expects to provide services to wholesale customers in the following categories: asset based energy sales, asset based capacity sales, non-asset based energy and capacity sales, and other wholesale transactions (including interfacing and scheduling services, energy services agreements, and pass through charges).

Services to wholesale customers include interfacing between the customer and MISO, including providing balancing services. Revenues from these customers for services and asset based capacity are included in Other Revenues (*e.g.*, for balancing services). Sales of asset based energy are treated as asset based margins and passed through the fuel clause. We also provide some non-asset based services to these customers (energy and capacity sales using financial instruments). The margins from non-asset based transactions as well as the fully allocated embedded costs related those activities are treated as below the line activities not included in the retail revenue requirement.

Attachment A to Schedule 14, Wholesale Customer Study provides a list of the types of services provided, and the ratemaking treatment for each type of service. Attachment B to Schedule 14, Wholesale Customer Study provides a wholesale customer summary including all current agreements by customer and the expected revenues for the years 2020 to 2022.

Q. DOES THE WHOLESALE CUSTOMER STUDY DEMONSTRATE THAT THE REVENUES ARE INCLUDED IN THE RETAIL RATE CASE?

A. Yes. After reviewing the services provided to our wholesale customers and the transactions associated with those services, the Company concludes that the ratemaking treatment of these transactions is consistent with past regulatory practice and the requirements of the Commission. Based on the treatment of these transactions, the Company believes that costs and revenues associated with wholesale customers are reflected properly in the test year.

VII. ANNUAL ADJUSTMENTS TO THE MYRP

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 MYRP Forecast revenue requirement. These adjustments were identified during our review of the 2020 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 MYRP Forecast. I also identify where another Company witness provides information to explain and support the adjustment.

Q. HOW ARE THESE ADJUSTMENTS PRESENTED IN YOUR TESTIMONY?

A. First, 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), 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 2020-2022 MYRP ADJUSTMENTS.

A. The following adjustments were made to rate base and the income statement where applicable. Rate base adjustments are shown on Schedules 10a-10c, Rate Base Adjustment Schedule. Income statement (revenue requirement) adjustments are shown on Schedules 11a-11c, 2020-2022 Income Statement Adjustment Schedule. As a general note, all revenue requirements shown on Schedules 11a-11c, are net of Interchange Agreement billings, where applicable, and capital related revenue requirements are shown calculated at the last authorized rate of return. Exhibit___(BCH-1), Schedule 12 MYRP Adjustment Summary provides adjustment amounts for the MYRP. Precedential Adjustments are set forth in Table 8 below.

Rate Case Adjustments

1) CIP Incentive
2) CIP Approved Program Costs
3) Interchange ROE
4) Incentive Compensation
5) Mankato Energy Center

6) Pension: Active Healthcare
7) Pension: Deferred Expense
8) Pension: Discount Rate Expense
9) Pension: Non-Qualified Expense
10) Pension: Retiree Medical Discount Rate Expense
11) Trading – Asset Based Margin
12) Trading – Non-Asset Based Margin
13) Trading – Non-Asset Based Administration
14) Transmission ROE

<u>Amortizations</u>

15) Aurora Deferral
16) LED Street Lighting Amortization
17) NOL Tax Reform Regulatory Amortization
18) Prairie Island EPU Deferred Costs
19) Rate Case Expense
20) Sherco 3 Depreciation

<u>Rider Removals</u>

21) Renewable Connect Removal and Avoided Capacity
22) Windsource Removal and Avoided Capacity
23) RES Rider
24) TCR Rider

<u>Secondary Cost of Service Calculations</u>

25) ADIT Pro-Rate – IRS Required
26) Cash Working Capital
27) Change in Cost of Capital
28) Net Operating Loss

A. Precedential Adjustments

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

A. Table 8 below is a list of Precedential Adjustments and their associated revenue requirement impact, based on past rate case precedent and Commission policy:

Table 8

Precedential Adjustments

Adjustment	2020 Test Year	2021 Plan Year	2022 Plan Year	Workpaper Reference
NSPM-Advertising	($2,846,381)	($2,912,580)	($2,967,208)	WP A-1
NSPM-Assn Dues	(734,495)	(724,005)	(723,460)	WP A-2
NSPM-Aviation	(2,051,482)	(2,094,034)	(2,139,338)	WP A-3
NSPM-Chamber of Commerce Dues	214,391	215,975	217,580	WP A-4
NSPM-Customer Deposits - A&G Expense	18,870	18,870	18,870	WP A-5
NSPM-Donations	1,851,065	1,851,564	1,852,349	WP A-6
NSPM-Econ Dev Donations	50,660	51,144	51,632	WP A-7
NSPM-Econ Develop	(56,203)	(56,203)	(56,203)	WP A-8
NSPM-Employee Expenses	(1,485,915)	(1,505,456)	(1,454,796)	WP A-9
NSPM-Foundation Admin	(113,729)	(115,300)	(116,960)	WP A-10
NSPM-Investor Relations	(358,045)	(362,548)	(364,736)	WP A-11
NSPM-Monticello EPU No Return	(11,636,431)	(10,390,232)	(9,242,691)	WP A-12
NSPM-Nobles Disallowed Assets	(191,073)	(177,039)	(163,345)	WP A-13
NSPM-Nuclear Retention Removal	(15,818)	(15,818)		WP A-14
NSPM-Other Revenue to 3 Year Average Adj	(2,193,405)	(2,255,012)	(2,807,078)	WP A-15
Sub-Total Precedential	($19,547,993)	($18,470,674)	($17,895,384)	

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 two electric rate cases

(Docket Nos. E002/GR-13-868 and E002/GR-15-826). 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 Table 8 above. This organization is intended to facilitate the review of and full support for each adjustment within the identified workpaper.

Q. WHAT IMPACT DO THESE PRECEDENTIAL ADJUSTMENTS HAVE ON THE DEFICIENCY?

A. Regulatory treatment of these precedential adjustments combined with the incentive compensation adjustments discussed below decrease our 2020 deficiency by approximately $35 million as shown in Table 9 below. The Company expects to incur these costs over the three years, so the cumulative cost to the Company is $100 million over the three-year MYRP.

Table 9

Regulatory Disallowances

Adjustment	2020 Test Year	2021 Plan Year	2022 Plan Year	Total
Total Precedential	($19,547,993)	($18,470,674)	($17,895,384)	($55,914,050)
Total Incentive	(15,255,273)	(16,182,118)	(17,045,714)	(48,483,105)
Total Disallowances	($34,803,265)	($34,652,792)	($34,941,098)	($104,397,155)

Q. HOW IS THE COMPANY INCORPORATING THESE ADJUSTMENTS INTO THE MYRP FORECAST?

A. These 15 precedential adjustments are combined in one column matching the Total row in Table 8 above to Schedules 11a–11c, 2020-2022 Income

Statement Adjustment Schedule. In total, these precedential adjustments represent a decrease in our rate request compared to our budgeted costs. The detail of the precedential adjustments in bridge schedule format can be seen in Exhibit___(BCH-1), Schedule 13, Precedential Adjustment Detail. In addition, as noted above, each respective workpaper referenced above contains a detail description of the adjustment, including the past precedent and related Commission Orders or Policy Statements.

Q. WITH RESPECT TO THE ECONOMIC DEVELOPMENT INCLUDED IN THE PRECEDENTIAL ADJUSTMENTS HAS THE COMPANY PERFORMED A COST BENEFIT ANALYSIS TO DETERMINE THAT THE BENEFITS OF THE ECONOMIC DEVELOPMENT PROGRAMS EXCEED THEIR COST TO RETAIL CUSTOMERS?

A. Yes. We completed a cost-benefit analysis supporting the inclusion of economic development costs in the MYRP Forecast. Exhibit___(BCH-1), Schedule 16, Economic Development Cost-Benefit Analysis, Attachments A and B provide the potential revenue and cost impacts of the addition of one commercial/industrial customer to NSPM's electric system due to economic development programs. The results indicate that the investments made by the Company to support economic development in our community have the potential to provide value to customers as soon as the first year.

B. Rate Case Adjustments

1) CIP Incentive

Q. PLEASE DESCRIBE THE CIP INCENTIVE ADJUSTMENT.

A. The CIP performance incentive is designed to compensate the Company for lost sales due to Company conservation efforts. The annual projected CIP performance incentive margin is included in the Other Revenue budget. The CIP performance margin is intended as an incentive to the Company and represents budgeted level in anticipation of achieving the CIP goals. An adjustment is necessary to remove the estimated performance margin from the MYRP Forecast. Failure to include this adjustment would flow the annual CIP performance incentive to customers by overstating operating revenues in the MYRP Forecast and therefore understating the revenue deficiency for the test year.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 41, column 10,
- Schedule 12, page 1, row 21, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A17.

2) CIP Approved Program Costs

Q. PLEASE DESCRIBE THE CIP APPROVED PROGRAM LEVELS ADJUSTMENT.

A. The MYRP Forecast CIP expenses and corresponding revenues have been set at the 2020 level of $102.37 million as proposed in Docket E,G002/CIP-16-115.

Because we make corresponding adjustments to both revenue and expense, this adjustment has no impact on the MYRP Forecast deficiency, as shown on:

- Schedule 11, page 1, row 41, column 9,

- Schedule 12, page 1, row 20, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A16.

I note that the decision of the Deputy Commissioner of the Minnesota Department of Commerce in Docket No. E,G002/CIP-16-115 authorizing a higher level of CIP expenditures is expected to be issued November 12, 2019. Obviously this timing did not allow the Company to incorporate the approved levels in this initial rate case filing. If necessary, the Company will propose an adjustment in Rebuttal Testimony to modify the CIP expenditures and offsetting revenues to reflect the final authorized level in the test year.

3) Interchange ROE

Q. PLEASE DESCRIBE THE INTERCHANGE ROE ADJUSTMENT.

A. We have adjusted the 2020-2022 MYRP interchange billings between NSPM and NSPW to reflect a proposed change to the Interchange Agreement ROE. On October 2, 2019, the NSP Companies filed with FERC revisions to the "Restated Agreement to Coordinate Planning and Operations and Interchange Power and Energy between Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin)," proposing to reduce the rate of return on common equity from 11.47 percent to 10.4 percent, effective January 1, 2020. The proposed changes are pending FERC acceptance.

This adjustment reflects the impact of the Interchange Agreement ROE change and increases MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 41, column 11,
- Schedule 12, page 1, row 22, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A18.

If FERC modifies the Interchange Agreement ROE to a level that is different from the NSP Companies' proposal, the Company will update the MYRP revenue requirement in Rebuttal Testimony to reflect the final accepted Interchange Agreement ROE.

4) Incentive Compensation

Q. PLEASE DESCRIBE THE INCENTIVE COMPENSATION ADJUSTMENT.

A. We have adjusted MYRP Forecast costs to exclude the budgeted costs of: 1) the long-term portion of the incentive compensation, other than incentive compensation related to environmental goals; 2) any non-corporate incentive plan costs; and 3) all Annual Incentive Plan amounts above 20 percent of each individual's base pay. Company witness Ms. Ruth K. Lowenthal discusses incentive compensation in her Direct Testimony.

This adjustment decreases MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 41, column 12,
- Schedule 12, page 1, row 23-25, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A19-A21.

5) Mankato Energy Center

Q. PLEASE DESCRIBE THE MANKATO ENERGY CENTER ADJUSTMENT.

A. The 2020-2022 budget developed in July 2019 assumed NSPM regulatory ownership of the Mankato Energy Center (MEC), including components of capital and O&M expenses. Based on the Commission's decision in Docket IP6949, E002/PA-18-702, these MEC-related capital and O&M expenses need to be removed, and the PPA costs need to be reinstated. This adjustment changes the 2020-2022 MYRP budget to reflect the Mankato Energy Center purchases as a PPA.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 41, column 5,
- Schedule 11, page 1, row 41, column 13,
- Schedule 12, page 1, row 26-27, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A22-A23.

6) Active Health Care Expense

Q. PLEASE DESCRIBE THE ACTIVE HEALTH CARE EXPENSE ADJUSTMENT.

A. The per-book amounts for active healthcare in the 2020-2022 budget include estimates due to a lag between when healthcare is provided and when the Company receives a bill for that care. This adjustment changes the per-book amounts in the MYRP Forecast so they reflect the actual incurred claim amounts during that period. Please see the Direct Testimony of Mr. Richard R. Schrubbe for a more information.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 41, column 14,
- Schedule 12, page 1, row 28, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A24.

7) Deferred Pension Expense

Q. PLEASE DESCRIBE THE DEFERRED PENSION EXPENSE ADJUSTMENT.

A. This adjustment reflects the annual amount of the three-year amortization of the XES Plan cap cumulative deferred balance. The cumulative deferred balance is discussed in the Direct Testimony of Mr. Schrubbe.

This adjustment impacts MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 41, column 15,
- Schedule 12, page 1, row 29, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A25.

8) Pension Discount Rate Expense

Q. PLEASE DESCRIBE THE PENSION DISCOUNT RATE EXPENSE ADJUSTMENT.

A. This adjustment reflects the Company's recalculation of its MYRP Forecast pension costs using a five-year average discount rate. The Company determined the five-year rolling average discount rate consistent with Order Point 7 in Docket No. E002/GR-13-868. Mr. Schrubbe discusses the pension discount rate in his Direct Testimony.

This adjustment impacts MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 41, column 16,
- Schedule 12, page 1, row 30, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A26.

9) Non-Qualified Pension Expense

Q. PLEASE DESCRIBE THE NON-QUALIFIED PENSION EXPENSE ADJUSTMENT.

A. This adjustment excludes from the MYRP Forecast all non-qualified pension expenses related to the Company's Supplemental Executive Retirement Plan (SERP) and Restoration Plan. Non-qualified pension expenses are discussed in the Direct Testimony of Ms. Lowenthal. Our treatment of SERP and restoration costs in this case is consistent with treatment of these costs in our last rate case, Docket No. E002/GR-15-826. As discussed further by Ms. Lowenthal, we are making the adjustment for Restoration Plan costs to reduce the number of disputed issues in this case.

This adjustment impacts MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 41, column 17,
- Schedule 12, page 1, row 31, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A27.

10) Retiree Medical Discount Rate Expense

Q. PLEASE DESCRIBE THE RETIREE MEDICAL DISCOUNT RATE PENSION EXPENSE ADJUSTMENT.

A. The Commission's Order in Docket No. E002/GR-13-868 states the discount rate used to calculate retiree medical benefit costs for ratemaking purposes shall be set to equal the five-year average of the FAS 106-based discount rates. An adjustment is necessary to reflect the use of the five-year average discount rate to calculate retiree medical benefits and reflect the appropriate expense level in the MYRP Forecast. Mr. Schrubbe discusses retiree medical benefits and the discount rate in his Direct Testimony.

This adjustment impacts MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 41, column 18,
- Schedule 12, page 1, row 32, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A28.

11) Trading – Asset Based Margin

Q. PLEASE DESCRIBE THE ASSET BASED MARGIN ADJUSTMENT.

A. Consistent with previous rate cases, the adjustment to Asset Based Margins excludes the budgeted asset based energy sales margins from the test year. As I previously explained, asset based energy sales margins are passed through to customers through the FCA. Accordingly, this adjustment ensures no double counting occurs between base rates and the FCA.

This adjustment impacts MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 41, column 19,
- Schedule 12, page 1, row 33, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A29.

This impact is offset by the amount of actual asset based margins credited to the fuel cost revenue requirement on a going forward basis in the FCA.

12) Trading – Non-Asset Based Margin

Q. PLEASE DESCRIBE THE NON-ASSET BASED MARGIN ADJUSTMENT.

A. Consistent with our process to develop test and plan year base rates, the adjustment to Non-Asset Based Margins excludes the non-asset based trading margins from the test year so that the Company retains all margins resulting from non-asset based trading activity. As discussed above, the Company excludes from the test year the fully allocated costs of performing activities associated with achieving these trades.

This adjustment impacts MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 41, column 21,
- Schedule 12, page 1, row 34, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A30.

13) Trading – Non-Asset Based Administration

Q. PLEASE DESCRIBE THE NON-ASSET TRADING ADJUSTMENT RELATED TO ADMINISTRATION.

A. This adjustment excludes the fully allocated non-asset based trading O&M and associated IT costs from the test year deficiency based on a cost study. The cost study measures the fully allocated non-asset based trading costs included in the 2020-2022 capital and O&M budget and is provided as Exhibit___(BCH-1), Schedule 17, Non-Asset Based Trading Cost Study.

This adjustment impacts MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 41, column 20,
- Schedule 12, page 1, row 35, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A31.

14) Transmission ROE

Q. PLEASE DESCRIBE THE TRANSMISSION ROE ADJUSTMENT.

A. In his Direct Testimony, Mr. Benson describes the MISO ROE complaints and the potential test year impact on transmission revenues and expenses of any final decision from FERC related to the November 2013 and February 2015 MISO ROE Complaints. The Company believes a determination at FERC on this matter should not impact the retail jurisdiction, and the cost of capital should be treated consistently across our rate base; therefore, we are proposing this adjustment to calculate the net transmission revenue credit using the ROE approved by the Commission in this case. For purposes of this filing, the adjustment was prepared based on the last authorized ROE of

9.06 percent for the TCR.[7] In final compliance, the Company will make an adjustment to reflect the final authorized ROE in this case.

This adjustment includes the impact on Attachment O, GG and MM from the MISO Transmission Formula Rate which will be partially offset in the TCR Rider removal of RECB revenue and expenses discussed in Sections VII and VIII of my testimony. This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 41, column 22,
- Schedule 12, page 1, row 36, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A32.

C. Amortizations

15) Aurora Deferral

Q. PLEASE DESCRIBE THE AURORA DEFERRAL EXPENSE AMORTIZATION.

A. The Commission's Order in Docket No. E-002/M-15-330 approved the power purchase agreement between Xcel Energy and Aurora Distributed Solar, LLC. This resource was disputed by the South Dakota Public Utilities Commission (SDPUC) in Docket EL16-037 and resulted in recovery limited to an energy proxy price (derived from the system average cost of fuel and purchased power), with no capacity component. The Company is therefore requesting authorization to recover the difference between the contracted

[7] In Docket No. E002/M-17-797 the Minnesota Public Utilities Commission ordered the following: Xcel Energy must "use an ROE of 9.06 percent in all electric dockets filed by the Company that require an ROE until the Commission issues an Order in the Company's next rate case authorizing a different

PPA and the proxy price through this case. Mr. Chamberlain discusses this request in his Direct Testimony. We are requesting recovery of these costs over the two-year period from 2020-2021, along with the ability to pass this cost on a going forward basis to MN customers through the FCA beginning January 1, 2022.

Q. PLEASE DESCRIBE HOW THE AURORA DEFERRAL EXPENSE AMORTIZATION ADJUSTMENT WAS CALCULATED.

A. This adjustment reflects 31 months of actual and 29 months of budgeted PPA costs in excess of the energy proxy price referenced above from January 1, 2017, the date the South Dakota Public Utilities Commission denied recovery, to January 1, 2022, the date the Company requests to shift recovery to the FCA. The total accumulated balance over the five years is then amortized over 24 months.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 41, column 6,
- Schedule 11, page 1, row 41, column 23,
- Schedule 12, page 1, row 39, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A33.

ROE." September 27, 2019 ORDER AUTHORIZING RIDER RECOVERY, SETTING RETURN ON EQUITY, AND SETTING FILING REQUIREMENTS, p. 8.

16) LED Street Lighting Amortization

Q. PLEASE DESCRIBE THE LED STREET LIGHTING AMORTIZATION.

A. The Commission's Order in Docket No. E002/GR-15-826 approved deferral of the LED Street Lighting revenue requirements. The Company is therefore requesting authorization to recover a total of $0.503 million in LED Street Lighting costs over the MYRP Forecast.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 41, column 7,
- Schedule 11, page 1, row 41, column 24,
- Schedule 12, page 1, row 40, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A34.

17) NOL Tax Reform Regulatory Amortization

Q. PLEASE DESCRIBE THE NOL TAX REFORM REGULATORY AMORTIZATION.

A. The Commission's Order in Docket No. E,G999/CI-17-895 approved the Company's proposed amortization level included in the TCJA refund calculation. This is being amortized over 23 years.

The adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 41, column 8,
- Schedule 11, page 1, row 41, column 25,

- Schedule 12, page 1, row 41, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A35.

18) Prairie Island EPU Deferred Costs

Q. PLEASE EXPLAIN THE ADJUSTMENT NEEDED TO RECOVER THE PRAIRIE ISLAND EXTENDED POWER UPRATE (EPU) DEFERRED COSTS.

A. The Commission's Order in Docket No. E002/GR-13-868 approved the recovery of the abandoned Prairie Island EPU project costs over the remaining life of the plant through an amortization expense. The Order also approved including this unrecovered investment in rate base, but limited the return on rate base related to this project to the weighted cost of debt.

The amortization and rate of return adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 41, column 9,
- Schedule 11, page 1, row 41, column 26,
- Schedule 12, page 1, row 42, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A36.

Q. PLEASE DESCRIBE THE PRAIRIE ISLAND EPU ADJUSTMENTS INCLUDED IN THE 2020-2022 MYRP COSS IN MORE DETAIL.

A. First, the various rate base and income statement components related to the amortization of this deferred cost are input as an adjustment to the cost of service. This results in the calculation of the overall revenue requirement associated with this project. Embedded in these calculations is a computation of return on rate base at the overall weighted cost of capital (debt and equity).

To adjust for the ordered weighted cost of debt return requirement, the Company computes the revenue requirements associated with the weighted cost of equity and includes the result of this calculation as Other Revenues to reduce the deficiency by this amount. Because this adjustment includes a return in the calculation, this adjustment will require a recalculation if return component weighted costs are adjusted during this case.

19) Rate Case Expense

Q. PLEASE DESCRIBE THE RATE CASE EXPENSE AMORTIZATION.

A. The Company is requesting authorization to recover a total of $5.382 million in rate case costs over the MYRP Forecast. We are requesting recovery of these costs over the three-year period 2020-2022, consistent with our Multi-Year Rate Plan.

Q. PLEASE DESCRIBE HOW RATE CASE EXPENSE WAS ESTIMATED.

A. The rate case expense budget was developed by first reviewing actual expenses incurred in our 2015 electric rate case. We built the 2020 rate case budget based upon a combination of our plans for outside experts, expected regulatory and legal fees and estimates for administrative costs such as required notices.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 41, column 27,

- Schedule 12, page 1, row 43, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A37.

20) Sherco 3 Depreciation

Q. PLEASE DESCRIBE THE SHERCO 3 DEPRECIATION DEFERRAL AMORTIZATION.

A. The Commission's Order in Docket No. E002/GR-12-961 required the Company to defer the depreciation expense incurred for Sherco 3 during the extended repair outage following the 2011 catastrophic event and amortize it over the remaining life of the plant.

The adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 41, column 10,
- Schedule 11, page 1, row 41, column 28,
- Schedule 12, page 1, row 44, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A38.

D. Rider Removals

21) Renewable Connect Removal and Avoided Capacity

Q. PLEASE DESCRIBE THE RENEWABLE CONNECT (R*C) REMOVAL AND AVOIDED CAPACITY ADJUSTMENT.

A. The Renewable*Connect program is a stand-alone retail service program with discrete revenues, purchase power contracts and operating expenses. We have excluded all Renewable*Connect revenues and associated expenses from our MYRP Forecast revenue requirements determination.

Renewable*Connect is a voluntary renewable energy program that gives customers an option to purchase renewable energy to meet all of their energy needs. Customers can choose to subscribe to a five or ten year term or on a month-to-month basis. A customer subscribing to Renewable*Connect is charged the Renewable*Connect price in lieu of the fuel clause pricing, which is based on the Company's current mix of energy resources.

Including Renewable*Connect as part of a utility's resource mix means that the utility avoided building or purchasing from other sources. The kWh cost of renewable energy purchased by a utility includes a capacity factor or value which would otherwise have been included in the utility's base rates and paid by all customers because all customers benefit from the capacity. This capacity credit is subtracted from the Renewable*Connect rate because it is a cost that should be shared by all customers, rather than only by Renewable*Connect customers. The Direct Testimony of Company witness Mr. Michael A. Peppin further supports the development of the Renewable*Connect avoided capacity credit.

The net of these adjustments impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 41, column 29,
- Schedule 12, page 1, row 47, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A39.

22) Windsource Removal and Avoided Capacity

Q. PLEASE DESCRIBE THE WINDSOURCE REMOVAL AND AVOIDED CAPACITY ADJUSTMENT.

A. The Windsource program is a stand-alone retail service program with discrete revenues, purchase power contracts and operating expenses. We have excluded all Windsource revenues and associated expenses from our MYRP Forecast revenue requirements determination.

Including wind energy generation as part of a utility's resource mix means that the utility avoided building or purchasing from other sources. The kWh cost of wind energy purchased by a utility includes a capacity factor or value which would otherwise have been included in the utility's base rates and paid by all customers because all customers benefit from the capacity. This capacity credit is subtracted from the Windsource rate because it is a cost that should be shared by all customers, rather than only by Windsource customers. The Direct Testimony of Company witness Mr. Michael A. Peppin further supports the development of the Windsource avoided capacity credit.

The net of these adjustments impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 41, column 32,
- Schedule 12, page 1, row 50, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A42.

23) RES Rider

Q. IS THE COMPANY PROPOSING CONTINUED USE OF THE RES RIDER DURING THE MYRP?

A. Yes. As I describe in detail in Section VIII, Costs Recovered in Riders, we propose continued use of the RES Rider during the MYRP for the projects that will not be placed in service as of December 31, 2019.

Q. PLEASE DESCRIBE THE RES RIDER REMOVAL ADJUSTMENT.

A. The RES Rider removal adjustment removes all costs and PTCs from the test year jurisdictional cost of service for the projects that we propose will stay in the rider after the implementation of final rates in this case. The RES Rider test year adjustment ensures no double recovery of these costs.

For PTCs related to energy production at other Company-owned wind farms, currently and proposed to be included in base rates, we propose to continue the true-up to actual PTCs in the RES Rider. These wind farms include Borders Wind Farm, Nobles Wind Farm, Pleasant Valley Wind Farm, Courtenay Wind Farm, Foxtail Wind Farm, Blazing Star I Wind Farm and Lake Benton Wind Farm. Finally, should the Company sell any Renewable Energy Credits (RECs), the proceeds from those sales would be shared with customers through the RES Rider.

Q. WHAT COSTS ARE INCLUDED IN THE RES RATE RIDER REMOVAL ADJUSTMENT?

A. This adjustment includes project costs and PTCs for the Blazing Star II Wind Farm, Freeborn Wind Farm, Crowned Ridge Wind Farm, Dakota Range

Wind Farm, Community Wind North Wind Farm, Jeffers Wind Farm and Mower Wind Farm, and RES Rider present revenue associated with these items that are proposed to be included in the RES Rider after the implementation of final rates. Costs or revenues associated with the PTC true-up and RECs sales occur only on an actual basis and, as such, require no test year adjustment.

This adjustment decreases the MYRP Forecast rate base by $549.960 million in 2020, as well as $942.039 million and $920.073 million in years 2021 and 2022 respectively. The adjustment has a net zero impact on the MYRP Forecast revenue requirements, as we expect full recovery in the RES rider. Support for these amounts can be found on:

- Schedule 10, page 1, row 41, column 11,
- Schedule 11, page 1, row 41, column 30,
- Schedule 12, page 1, row 48, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A40.

24) TCR Rider

Q. IS THE COMPANY PROPOSING CONTINUED USE OF THE TCR RIDER DURING THE MYRP?

A. Yes. As I describe in detail in Section VIII, Costs Recovered in Riders, we propose continued use of the TCR Rider during the MYRP for the projects that will not be placed in service as of December 31, 2019 and MISO Regional Expansion Criteria and Benefits (RECB) Schedule 26 and 26A revenues net of expenses.

Q. PLEASE DESCRIBE THE TCR RIDER REMOVAL ADJUSTMENT.

A. The TCR Rider removal adjustment removes all costs and revenues from the MYRP Forecast jurisdictional cost of service for the Advanced Distribution Management System (ADMS) and Huntley-Wilmarth projects, as well as MISO RECB Schedule 26 and 26A net revenues. In our TCR Rider filing, we proposed to include these project costs and revenues in the TCR Rider, and to continue cost recovery for these projects in the rider after the implementation of final rates in this case. The TCR Rider MYRP Forecast adjustment ensures no double recovery of these costs.

This adjustment decreases the MYRP Forecast rate base by $43.772 million in 2020, as well as $66.423 million and $74.773 million in years 2021 and 2022 respectively. The adjustment has a net zero impact on the MYRP Forecast revenue requirements, as we expect full recovery in the TCR Rider. Support for these amounts can be found on:

- Schedule 10, page 1, row 41, column 12,
- Schedule 11, page 1, row 41, column 31,
- Schedule 12, page 1, row 49, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A41.

Q. IS THE TCR RIDER REMOVAL BASED ON THE SAME DATA AS WAS USED IN THE 2019-2020 TCR RIDER FILING?

A. Yes, the same vintage of data was used for both the rate case test year and our TCR Rider filing. However, we note the two filings calculate revenue requirements using different rate base averaging methodologies, and certain inputs in the rider are required to use historically-approved values. Therefore, even though the underlying data is the same, small variances exist in the revenue requirement calculations between the two filings.

E. Secondary Cost of Service Calculations

25) ADIT Pro-Rate – IRS Required

Q. PLEASE DESCRIBE THE ADIT PRO-RATE 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 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. Given that the Company's MYRP 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 pro-ration 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 pro-rate method to only the forecast entries to this balance. During final validation on the ADIT pro-rate calculation, we identified that the pro-rate 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. Support for this calculation is included in Exhibit___(BCH-1), Schedule 19, ADIT Pro-

Rate. The IRS requirements for this adjustment are described in more detail in the Direct Testimony of Ms. Wold.

The adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 41, column 13,
- Schedule 11, page 1, row 41, column 33,
- Schedule 12, page 1, row 53, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A43.

26) 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. The adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 41, column 14,
- Schedule 11, page 1, row 41, column 34,
- Schedule 12, page 1, row 54, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A44.

27) Change in Cost of Capital

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

A. The change in the cost of capital adjustment is the effect of the changes in the overall cost of capital between the cost of capital (also referred to as the overall rate of return, or ROR) being requested in this case for each year of the MYRP and the effective cost of capital authorized in Docket No. E002/GR-15-826. Table 10 below provides the requested rate of return in this case,[8] and the difference in the rate of return for each year of the MYRP forecast relative to the effective 2019 rate of return of 7.08 percent authorized in Docket No. E002/GR-15-826.

Table 10

Proposed Rate of Return

	2020 Test Year	2021 Plan Year	2022 Plan Year
Proposed Rate of Return	7.42%	7.42%	7.44%
Difference relative to 7.08%	0.34%	0.34%	0.36%

On Schedules 11a-11c, 2020-2022 Income Statement Adjustment Schedule, the revenue deficiencies for the base data and all other adjustments are calculated at the 7.08 percent overall cost of capital. This adjustment

[8] The amounts presented in Table 10 above represent our requested ROR, but they do not match the ROR included in the final rate financial schedules in this filing due to a bond offering after the cost of service was generated. As I note in Section F below, the Company has made this change for interim rates and will adjust for this change in rebuttal testimony.

calculates the required operating income resulting from the change in the overall cost of capital applied to the requested rate base.

We calculated the revenue deficiencies in this manner so that changes, if any, in the overall cost of capital that occurs during the duration of the rate case do not affect the revenue requirements for each adjustment. The adjustment reflects both the change in the stated ROE of 9.20 percent in our last rate case to 10.20 percent (for final rates only) as well as the changes in short-term and long-term debt.

The impact of these adjustments on the MYRP Forecast revenue requirements is shown on:

- Schedule 11, page 1, row 41, column 35,
- Volume 4, Section VIII Adjustments, Tab A46,
- Schedules 11, 2020-2022 Income Statement Adjustment Schedule, Page 3, Column 34.

28) Net Operating Loss

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

A. The NSPM income tax determination was in a net operating loss (NOL) position through 2018. 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 tax credits that have been deferred and tracked for use in future periods. The Company worked with the Department on this issue, which resulted in a process for reporting these deferred balances and returning to customers the revenue requirement reduction associated with the utilization of these deferred balances in the form of a refund or as a reduction to base rates.

Net Operating Losses, 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 NET OPERATING LOSSES IN THIS CASE?

A. No. The Company was able to utilize the remainder of the deductions previously deferred.

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 2020-2022 MYRP, but due to the amount of federal tax credits earned during the year, the DTA is increasing in each year of the MYRP. 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.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 41, column 16,
- Schedule 11, page 1, row 41, column 36,
- Schedule 12, page 1, row 55, columns 5 through 7,
- Schedule 20, Net Operating Loss,
- Volume 4, Section VIII Adjustments, Tab A45.

F. Rebuttal Adjustments

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION?

A. In this section, I provide details related to three adjustments we identified during our final quality assurance reviews performed just prior to this filing. These adjustments reflect small changes we believe necessary that we identified after we finalized our cost of service and rate design that we were not able to incorporate due to timing constraints. Consistent with prior rate cases, we propose to incorporate these adjustments into the MYRP Forecast revenue requirement when we file Rebuttal Testimony.

29) Cost of Capital

Q. PLEASE DESCRIBE THE REBUTTAL ADJUSTMENT RELATED TO COST OF CAPITAL.

A. As discussed previously in my testimony, the Company issued a bond after the cost of service was generated, which resulted in a decrease to the cost of capital. This change will reduce the overall deficiency. This change is reflected in our interim rate revenue deficiency in our Interim Rate Petition, Schedule B, Part 3 of 3, page 1. Our cost of service will be corrected in Rebuttal for final rates.

30) Railroad Island

Q. PLEASE DESCRIBE THE REBUTTAL ADJUSTMENT RELATED TO THE RAILROAD ISLAND SOLAR GARDEN.

A. The Company was completing validations on capital expenditures included in the rate case and determined that costs for this project was inadvertently included. This change will reduce our 2020 test year deficiency by $0.044 million. This change is reflected in our interim rate revenue deficiency, and will be corrected in Rebuttal Testimony for final rates.

31) ADIT Pro-Rate for IRS

Q. PLEASE DESCRIBE THE REBUTTAL ADJUSTMENT RELATED TO ADIT PRO-RATE FOR IRS.

A. As discussed above, the Company was completing validation on the ADIT pro-rate calculation and identified that the pro-rate factor used in our model had inadvertently included a double averaging of the factor. This change will increase the overall deficiency by the amounts shown in Table 11 below. Our interim rate petition has been corrected to include the correct pro-rate factor, and we will correct the factor in Rebuttal Testimony for final rates. Support for this adjustment can be found in Volume 4, MYRP Workpapers, Section VIII Adjustments, Tab A43.

Table 11

2020-2022 ADIT Pro-Rate ($ in millions)

2020 Test Year	2021 Plan Year	2022 Plan Year	Total
($0.440)	$0.031	$0.726	$0.317

32) Lobbying Expense

Q. PLEASE DESCRIBE THE REBUTTAL ADJUSTMENT RELATED TO LOBBYING EXPENSE.

A. The Company was completing final validation and discovered that $0.178 million of lobbying labor was included in our 2020 test year budget. An adjustment will be made to reduce the overall deficiency. This change is reflected in our interim rate revenue deficiency, and will be corrected in Rebuttal for final rates.

33) Fleet Capital Additions

Q. PLEASE DESCRIBE THE REBUTTAL ADJUSTMENT RELATED TO FLEET CAPITAL ADDITIONS.

A. After the cost of service was completed, we discovered that the Fleet capital additions budgeted for Energy Supply and Nuclear for 2020-2022 did not have closing patterns to incorporate these capital additions in the Company's calculation of the Minnesota cost of service. We will include these additions in an adjustment made in Rebuttal Testimony. This change will increase the overall deficiency. This change is not included in interim rates, but will be corrected in Rebuttal Testimony for final rates.

34) FERC Audits (Potential Adjustment)

Q. PLEASE DESCRIBE THE POTENTIAL REBUTTAL ADJUSTMENT RELATED TO THE FERC AUDITS.

A. As discussed in the Direct Testimony of Ms. Schmidt, the Company is currently evaluating the impacts of the Xcel Energy Services Inc. FERC audit findings but expects any impact to the MYRP Forecast (if there is any impact) to be immaterial.

The FERC audit findings related to the NSPM FERC audit were incorporated into the transmission revenue and expense MYRP Forecast included in the rate case, to the extent they impacted the transmission formula development. The audit findings would have no financial impact on other rate base, so no Rebuttal adjustment is anticipated.

35) Bonus Tax Depreciation (Potential Adjustment)

Q. PLEASE DESCRIBE THE POTENTIAL REBUTTAL ADJUSTMENT RELATED TO BONUS TAX DEPRECIATION.

A. The MYRP Forecast was prepared in a manner consistent with the tax guidance available at the time of preparation and filing of our 2018 tax return. The 2018 tax return was filed on September 12, 2019. Based on the guidance available, no bonus depreciation beyond December 31, 2017 was included in the filing. Subsequent to the filing of our return, the United States Treasury and the IRS released final and proposed regulations on 100 percent bonus depreciation and phase down of previous bonus depreciation, respectively. The Company is working to determine how, if at all, the new guidance impacts the MYRP Forecast and in Rebuttal will propose any adjustment that may be needed to reflect the new guidance, but does not believe it to be material to our cost of service. We will include these adjustments in our Rebuttal Testimony.

VIII. COSTS RECOVERED IN RIDERS

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

A. In this section, I present our proposed treatment of costs recovered in riders during the MYRP period, including riders that we propose to continue to use and costs we propose to move to base rates. I provide detailed information supporting the adjustments to the MYRP Forecast that I presented in Section VII of my testimony.

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

A. The Company currently uses six cost recovery riders:

- Renewable Energy Standards (RES) Rider,
- Transmission Cost Recovery (TCR) Rider,
- Renewable Development Fund (RDF) Rider,
- Conservation Improvement Program (CIP) Rider,
- Windsource Rider,
- Renewable Connect Rider, and
- Fuel Clause Adjustment Rider (FCA).

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

A. As discussed and supported in the Direct Testimony of Mr. Chamberlain, we propose to:

- Continue use of the RES Rider for recovery of costs for the Blazing Star II, Freeborn, Crowned Ridge, Dakota Range, Community Wind

North, Jeffers and Mower Wind Farms and the associated PTCs, the PTC true-up for other Company-owned wind projects, and sharing with customers potential proceeds related to any Renewable Energy Credits the Company may sell in the future after the implementation of final rates in this case. All current and proposed rider projects and revenue credits will be collected through the RES Rider during the interim rate period.

- Continue use of the TCR Rider, with costs for ADMS and Huntley Wilmarth, and MISO RECB Schedule 26 and 26A net revenues to continue to be included in the rider after implementation of final rates in this case. All current and proposed rider projects and revenue credits will be collected through the RES Rider during the interim rate period.
- Continue use of the RDF Rider, CIP Rider, Windsource Rider, Renewable Connect Rider, and the FCA in their current forms.

In the following subsections of my testimony, I will address our proposed rate case treatment for each of these riders in detail, and discuss how the Company ensures there is no double recovery of these costs.

Q. WHAT IS THE COMPANY'S BASE RATE REVENUE REQUIREMENT EXCLUSIVE OF RIDER ROLL-INS?

A. Our proposed total revenue requirement in 2020, 2021, and 2022, including our proposed increase in base rates, is approximately \$2.4 billion in 2020, \$2.5 billion in 2021 and \$2.6 billion in 2022, as shown in Table 12 below.

Table 12

Total Cost Recovery Including Riders

	$ in Thousands		
Recovery Method	**2020 Test Year**	**2021 Plan Year**	**2022 Plan Year**
Present Revenues	$3,121,140	$3,080,944	$3,069,438
Cumulative Rate Increase	201,427	347,795	466,104
Proposed Revenues	3,322,567	3,428,739	3,535,542
Less: Rider Revenue included in present revenue			
TCR Rider	88,375	85,369	82,638
CIP Rider	15,868	16,367	16,351
FCA Rider	796,051	796,051	796,051
RDF Rider	34,361	33,888	37,139
RES Rider	27,082	21,069	16,340
Total Rider Revenue included in present revenue	961,737	952,743	948,519
Net Base Rate Revenue Requirement	**2,360,830**	**2,475,996**	**2,587,023**

Rate rider recovery estimates are preliminary, are subject to change, and are also subject to the Commission's decision in individual rate rider dockets. We provide this information so that the Commission, parties, and our customers can understand the combined impact of our requests.

A. RES Rider

Q. WHAT IS THE RES RIDER?

A. The RES Rider is authorized by Minn. Stat. § 216B.1645, subd. 2a for the recovery of a utility's investments, expenses, or costs associated with facilities constructed, owned, or operated by a utility to satisfy the Minnesota Renewable Energy Standard.

Q. WHAT COSTS ARE CURRENTLY INCLUDED IN THE RES RIDER?

A. The Commission's Order in Docket No. E002/M-17-818 approved our 2017 and 2018 RES Rider request to recover the costs of the following projects in the RES Rider:

- Courtenay Wind Farm,
- Foxtail Wind Farm,
- Blazing Star I Wind Farm,
- Lake Benton Wind Farm,
- Blazing Star II Wind Farm,
- Freeborn Wind Farm,
- Crowned Ridge Wind Farm,
- PTCs for all wind farms above,
- PTC true up for wind farms included in base, and
- REC sales proceeds.

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE RES RIDER DURING THE MULTI-YEAR RATE PLAN?

A. As described earlier, we propose to:

- Move Courtenay Wind Farm, Foxtail Wind Farm, Blazing Star I Wind Farm and Lake Benton Wind Farm projects from RES Rider recovery to base rate recovery coincident with implementation of final rates in this rate case;
- Continue including Costs and Production Tax Credits of the Blazing Star II Wind Farm, Freeborn Wind Farm and Crowned Ridge Wind Farm in the RES Rider;

- Begin recovery of costs and refunds for PTCs on Dakota Range Wind Farm;
- In the RES Rider, true-up actual PTCs related to energy production at Borders Wind Farm, Nobles Wind Farm, Pleasant Valley Wind Farm, Courtenay Wind Farm, Foxtail Wind Farm, Blazing Star I Wind Farm and Lake Benton Wind Farm compared to the amount included in base rates; and
- Include in the RES Rider customers' share of potential proceeds related to any Renewable Energy Credits the Company may sell in the future.

These costs are fully supported in our 2019 and 2020 RES Rider petition being prepared concurrently with the preparation of my Direct Testimony.

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S REQUEST FOR RECOVERY OF THE WIND PROJECTS GOING INTO SERVICE IN 2020 AND BEYOND IN THE RES RIDER.

A. As described by Mr. Chamberlain, the Company proposes to recover all wind farms going into service in 2020 and beyond through the RES Rider. We propose to recover the capital-related revenue requirements and property taxes as well as incremental operating and maintenance expenses. We also propose to include all of the PTCs associated with these projects in the RES Rider. Therefore, we have not included any PTCs for these projects in the 2020-2022 MYRP as a part of our 2020-2022 MYRP.

Q. HOW IS THE RES RIDER TREATED WITH RESPECT TO PTCS IN THE 2020-2022 MYRP?

A. The Company requests PTC treatment consistent with the previously approved process. Specifically, we request that:

1) A new baseline PTC will be set in this rate case. We have included PTC amounts shown in Table 7 above as the base amount in the 2020-2022 MYRP. See Schedule 18, Production Tax Credits. These PTCs are generated from the Nobles, Pleasant Valley, Border, Courtenay, Foxtail, Blazing Star I and Lake Benton Winds facilities which are included in the 2020-2022 MYRP.
2) The difference between actual and baseline PTCs be recorded in the RES Tracker account.
3) The difference will be either refunded to, or recovered from, customers as established in future RES Rider filings.

Because we propose that the true-up between the level of PTCs included in base rates through this MYRP and the actual amount of PTCs earned in the respective period would occur through the RES Rider, we do not anticipate a need to address this issue in the base rate revenue requirement in the final compliance filing.

Q. WHAT ADJUSTMENT HAVE YOU MADE TO ENSURE NO DOUBLE RECOVERY OF COSTS RECOVERED IN THE RES RIDER AFTER THE IMPLEMENTATION OF FINAL RATES IN THIS CASE?

A. The project costs and revenues associated with the projects remaining in the RES Rider have been removed from our 2020-2022 MYRP. A review is also done for each RES filing to ensure that no costs included in base rates are included in the RES filing. I provide information related to the 2020-2022

MYRP adjustment that ensures no double recovery of these costs in Section VII.D. Rider Removals, RES Rider Adjustment 23.

B. TCR Rider

Q. WHAT IS THE TCR RIDER?

A. The TCR Rider is authorized by Minn. Stat. § 216B.16, subd. 7b to allow the recovery of Minnesota jurisdictional costs related to transmission and grid modernization investments and for MISO charges incurred for projects for which MISO assigns regional costs under Schedule 26 and Schedule 26A of its Tariff.

Q. WHAT COSTS ARE CURRENTLY INCLUDED IN THE TCR RIDER?

A. The Commission's Order in Docket No. E002/M-17-797 approved our 2017 and 2018 TCR Rider request to recover the following projects in the TCR Rider:

- ADMS,
- CapX2020 Brookings,
- CapX2020 Fargo,
- CapX2020 La Crosse,
- Big Stone – Brookings,
- La Crosse – Madison, and
- MISO RECB Schedule 26 and 26A net revenue.

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE TCR RIDER DURING THE MULTI-YEAR RATE PLAN?

A. As described earlier, we propose to:

- Move the three CapX2020 La Crosse projects, CapX2020 Brookings, CapX2020 Fargo, Big Stone–Brookings, and La Crosse-Madison projects from TCR Rider recovery to base rate recovery coincident with implementation of final rates in this rate case;
- Continue recovery of the ADMS project in the TCR Rider;
- Begin recovery of the Huntley–Wilmarth project in the TCR Rider effective January 1, 2019. This request will be included 2019 and 2020 TCR Rider filing, which will follow the filing of this rate case; and
- Continue recovery of MISO RECB Schedule 26 and 26A net revenue in the TCR Rider.

These costs are fully supported in our 2019 and 2020 TCR petition, which is being prepared concurrently with the preparation of my Direct Testimony.

Q. PLEASE DESCRIBE THE PROJECTS THAT WILL REMAIN IN THE TCR RIDER AFTER THE IMPLEMENTATION OF FINAL RATES.

A. The Company is requesting continued recovery of the ADMS project, and to begin recovery of the Huntley–Wilmarth project through the TCR Rider. We propose to recover these projects through the TCR Rider because these are large qualifying projects that are not yet fully in service. We are also requesting to continue recovery of the MISO RECB Schedule 26 and 26A net revenues through the TCR Rider.

Q. WHAT ADJUSTMENT HAVE YOU MADE TO ENSURE NO DOUBLE RECOVERY OF PROJECTS CONTINUING RECOVERY IN THE TCR RIDER AFTER THE IMPLEMENTATION OF FINAL RATES IN THIS CASE?

A. The project costs and revenues remaining in the TCR Rider have been removed from our 2020-2022 MYRP. A review is also done for each TCR filing to ensure that no costs included in base, are included in the TCR filing. I provide information related to the 2020-2022 MYRP adjustment that ensures no double recovery of these costs in Section VII.D. Rider Removals, TCR Rider Adjustment 24.

C. TCR and RES Rider Roll-In

Q. YOU NOTED YOU ARE PROPOSING TO MOVE PROJECTS TO BASE RATES AT THE CONCLUSION OF THIS RATE CASE. PLEASE DESCRIBE HOW THESE PROJECTS WILL BE ROLLED IN TO BASE RATES.

A. As noted above, we propose to move projects from the TCR and RES riders to base rates at the conclusion of this case because it reduces the Interim Rate increase and helps eliminate any potential for double recovery of costs. Coincident with the implementation of final rates in this rate case, the project costs will be removed from the TCR and RES Riders for the remaining months of the year and final rates will be designed to recover the costs of these projects. This approach is consistent with the method used in Docket No. E002/GR-10-971, where we moved the Metropolitan Emission Reduction Project (MERP) costs recovered through the Environmental Improvement Rider (EIR) and the Nobles Wind, Grand Meadow Wind and Wind2Battery projects recovered through the RES Rider into base rates when final rates were implemented in that case.

More specifically, the TCR and RES rate riders will be updated to exclude costs for these projects from the TCR and RES Riders for the remaining months of the year following implementation. The TCR and RES present revenues will be excluded from the 2021 plan year and final rates will be designed to recover the final revenue requirement approved by the Commission, including the final revenue requirement for these projects. The interim rate refund will not be affected for these projects, as any over/under recovery during the Interim Rate period related to these projects will remain in the TCR or RES rider.

Q. WHAT DOES THE COMPANY PROPOSE TO INCLUDE IN ITS FINAL RATE COMPLIANCE TO SUPPORT MOVEMENT OF THESE PROJECTS FROM THE TCR RIDER TO BASE RATES?

A. We propose to submit a TCR and RES Rider compliance reports with Final Rate compliance. This report will clearly identify the revenue requirements removed from the TCR and RES Riders, the revenue recovered from customers for the projects moving to base rates during the Interim Rate period, and the development of the revised TCR and RES Rider adjustment factors. The Company anticipates this process will be similar to the process used to move recovery of CIP costs from the CIP Rider to base rates.

Q. HOW ARE THE PROJECTS THAT WILL MOVE TO BASE RATES TREATED DURING THE INTERIM RATE PERIOD?

A. During the interim rate period, the Company proposes that the identified projects continue recovery through the TCR or RES Riders, along with the other costs that we are proposing to continue to recover through the TCR and RES Riders after implementation of final rates.

Q. IF YOU ARE PROPOSING TO INCLUDE THE PROJECTS IN THE TCR AND RES RIDERS DURING THE INTERIM RATE PERIOD, HOW WILL YOU ENSURE NO DOUBLE RECOVERY OF THESE PROJECT COSTS OCCURS DURING THIS TIME?

A. Because we are proposing to continue recovery of these projects through the TCR and RES Riders during the interim period and move these projects into base rates at the end of this case. The 2020 test year also includes the project costs in the test year cost of service as well as the project revenues (from the TCR Rider) in present revenue. Thus, an interim rate adjustment is necessary to ensure no double recovery of these costs during the interim rate period. Accordingly, our 2020 and 2021 Interim Rate requests each include an adjustment to remove the projects identified to roll into base rates and present revenue and revenue requirements from the development of Interim Rates.

Q. PLEASE PROVIDE ADDITIONAL DETAIL RELATED TO THE INTERIM RATE ADJUSTMENT FOR THE TCR AND RES RIDER COSTS.

A. The Interim Rate Adjustment removes the project costs and revenue requirements included in the 2020 test year and 2021 plan year from the Interim Cost of Service. This adjustment decreases the Interim Cost of Service rate base and revenue deficiency by the amounts shown in table 13 below.

Table 13

Rider Removals from Interim Rates ($ in millions)

	Decrease in Rate Base		Decrease in Revenue Requirement	
	2020	2021	2020	2021
TCR Rider	$610.507	$587.378	$5.141	$4.946
RES Rider	577.286	515.166	4.861	4.338
TOTAL Rider Removal	$1,187.793	$1,102.544	$10.002	$9.284

The TCR and RES Rider removal for Interim Rates results in a reduction to our Interim Rate request primarily because the present revenue from the TCR and RES Rider revenue requirements are calculated at the last authorized rate of return rather than the rate of return requested in this case. Additional detail on these adjustments can be found in Volume 1, Notice of Change in Rates and Interim Rate Petition, Interim Rate Supporting Schedules and Workpapers.

Q. DO YOU PROVIDE ANY OTHER INFORMATION RELATED TO TREATMENT OF TCR AND RES RIDER COSTS AND PROJECTS DURING THE MULTI-YEAR RATE PLAN PERIOD?

A. Yes. Exhibit___(BCH-1), Schedule 22, Rider Roll-in Timeline, provides a timeline illustrating how projects will be rolled in to base rates or will remain in the TCR and RES Riders during the course of the multi-year rate plan.

D. RDF Rider

Q. WHAT COSTS ARE RECOVERED THROUGH THE RDF RIDER?

A. Commission-approved RDF costs pursuant to Minn. Stat. §§ 116C.779 and 216B.1645, subd. 2 are recovered from retail customers through the RDF Rider.

Q. HOW IS THE RDF RIDER TREATED IN THE MYRP FORECAST?

A. Both revenue and amortization expense for the RDF Rider are included in the MYRP Forecast. The amount of each is equal and, therefore, does not contribute to the MYRP Forecast deficiency. Any true-up of the revenues and costs will occur in the RDF Rider, such that there will be no need to address a change in revenue requirement in the final compliance filing.

E. CIP Rider

Q. WHAT COSTS ARE RECOVERED THROUGH THE CIP RIDER?

A. The CIP Rider is designed to recover conservation and demand-side management program costs that are incremental to the level collected in base rates. Base electric rates are designed to include conservation and demand-side management cost at an authorized level approved by the Deputy Commissioner of the Minnesota Department of Commerce, Division of Energy Resources for a given test year. The CIP Rider collects any incremental conservation and demand-side management costs above the authorized level in final base rates.

Q. HOW IS THE CIP RIDER TREATED IN THE MYRP FORECAST?

A. As discussed in Section VII, Annual Adjustments to the Test Year, the CIP Rider amount in the case is at the level needed to assure that the CIP revenue (Base and Rider) is equal to the expense in the MYRP Forecast. With the total amount of CIP expense and CIP revenue equal, the overall CIP program does not contribute to the test year deficiency.

F. Windsource Rider

Q. WHAT COSTS ARE RECOVERED THROUGH THE WINDSOURCE RIDER?

A. Costs related to the Windsource program, a stand-alone retail service program with discrete revenues, purchase power contracts and operating expenses, are recovered through the Windsource Rider.

Q. HOW IS THE WINDSOURCE RIDER TREATED IN THE MYRP FORECAST?

A. All revenue and expense related to the Windsource program is excluded from the MYRP Forecast. The Windsource rider removal adjustment shown in column 32 of Exhibit___(BCH-1), Schedules 11a-11c, 2020-2022 Income Statement Adjustment Schedules reflects the removal of the Windsource related expenses and revenue included in base data, and does not impact the deficiency. Any true up of the revenues and costs incurred during the MYRP Forecast will occur in the Windsource Rider and, therefore, there will be no need to address a change in revenue requirement in the final compliance filing. Further information is provided in Section VII, Annual Adjustments to the Test Year.

G. Renewable*Connect Rider

Q. WHAT COSTS ARE RECOVERED THROUGH THE RENEWABLE*CONNECT RIDER?

A. Costs related to the Renewable*Connect program, a stand-alone retail service program with discrete revenues, purchase power contracts and operating expenses, are recovered through the Renewable*Connect Rider.

Q. HOW IS THE RENEWABLE*CONNECT RIDER TREATED IN THE MYRP FORECAST?

A. All revenue and expense related to the Renewable*Connect program is excluded from the MYRP Forecast. The Renewable*Connect Rider removal adjustment shown in column 29 of Schedules 11a-11c, 2020-2022 Income Statement Adjustment Schedule reflects the removal of the Renewable*Connect-related expenses and revenue included in base data, and does not impact the deficiency. Any true-up of the revenues and costs incurred during the MYRP Forecast will occur in the Renewable*Connect Rider, such that there will be no need to address a change in revenue requirement in the final compliance filing. Further information is provided in Section VII, Annual Adjustments to the Test Year.

H. Fuel Clause Adjustment (FCA)

Q. WHAT COSTS ARE RECOVERED THROUGH THE FCA?

A. Fuel and purchased energy are recovered from customers through the FCA.

Q. HOW IS THE FCA TREATED IN THE MYRP FORECAST?

A. Both revenue and fuel expenses recovered through the FCA are included in the MYRP Forecast, and the total amount of each is equal. Any true-up of the revenues and costs during the MYRP Forecast will occur in the FCA and, therefore, there will be no need to address a change in revenue requirement in the final compliance filing. I provide a reconciliation of fuel costs and revenues in the Cost of Service in Schedule 21, Fuel Reconciliation. As required by the Commission in its October 17, 2019 decision in Docket No. E999/CI-03-802 (although no Order has yet been issued as of the finalization of my Direct Testimony), this schedule illustrates that fuel costs are equal to fuel costs to be recovered through the FCA and thus the Company's proposed base rates do not include any amount of FCA costs.

I. Electric Vehicle Program Tracker

Q. PLEASE DESCRIBE THE STATUS OF THE ELECTRIC VEHICLE TRACKER AND DEFERRAL.

A. In its June 22, 2015, Order in Docket No. E002/M-15-111, the Commission approved the Company using a tracker account to defer costs associated with electric vehicle (EV) rate education and outreach activities. Consistent with Minn. Stat. § 216B.1614, subd. 2(2), the Company attributes costs to the tracker associated with providing general EV information, as well as EV rate-specific information. Additionally, in granting approval for several EV pilots in its July 17, 2019 Order in Docket No. E002/M-18-643, the Commission approved deferred accounting for Xcel Energy's O&M and depreciation expenses related to the capital assets that are placed in service for these pilots. This deferred accounting applied to expenses incurred between the date of the Commission's Order (July 17, 2019) and January 1, 2020.

Q. WHAT IS THE COMPANY'S PROPOSED TREATMENT OF EV PILOT COSTS DURING THE MYRP?

A. The Company proposes to incorporate the balance in the EV tracker and the final deferral balance related to Docket No. E002/18-643 into a three-year amortization over the MYRP to ensure that all expenses incurred up until January 1, 2020 are included in base rates. The total amount of these costs will be known at the time of Rebuttal Testimony (which is anticipated to be due after the conclusion of calendar year 2020), and will therefore be updated at that time.

As noted in the Direct Testimony of Ms. Bloch, certain O&M expenses related to the EV pilots approved in Docket No. E002/M-18-643 and proposed in the Company's June 2019 Transportation Electrification Plan (Docket No. E999/CI-17-879) are not yet included in the rate case. Going forward, the Company proposes to either continue use of the EV tracker account that was established in Docket No. E002/M-15-111 to track these costs for future recovery or, if that option is not preferred, include these expenses in O&M expenses as a Rebuttal Testimony adjustment. This omitted O&M amounts to: (1) $2.3 million (2020); (2) $2.7 million (2021); and (3) $2.3 million (2022).

IX. COMPLIANCE WITH PRIOR COMMISSION ORDERS

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

A. The Completeness Checklist included in the Direct Testimony of Mr. Chamberlain as Exhibit___(GPC-1), Schedule 2 documents how our rate case filing includes information required by Rule or prior Commission Orders, and provides specific references to the testimony of Company witnesses that addresses each requirement. In this section of my testimony, I identify and provide information related to specific requirements from prior Commission Orders that have not been addressed elsewhere in my testimony.

A. General Rate Case – Docket No. E002/GR-12-961

1) Mapping to FERC Form 1

Order Point 47 from Docket E002/GR-12-961 stated:

> Expanding upon the information filed under Minnesota Rules 7825.4000(B) and 7825.4100(B), direct the Company to include in its initial filing of its next rate case balance sheet and income statement reconciliations between its FERC Form 1 and its general ledger accounts for each of the three most recent calendar years relative to the rate case test year. The schedules provided should be produced in like manner as requested and illustrated in the Department's Information Request 128-Revised, marked in the record as Exhibit 163, DOC Attachment ACB-15.

These requirements have been met. The mapping to FERC Form 1 is located in Volume 3, Required Information, Section IV, Other Required Information, Tab 5, GAAP/FERC/COSS Comparison. There we provide accounting of the NSPM Total Company for 2015 to 2018. For each year, we provide the GAAP financial statements reconciled to the FERC Form 1. We then provide the FERC Form 1 reconciled to the Minnesota Jurisdictional Annual Report Total Company amounts.

2) Changes Between Actuals and MYRP Forecast

Order Point 47 also requests explanations for deviations ten percent or greater (+/- 10 percent) "between actuals and [the Company's] test-year request." Explanations of operating expense variations of +/-5 percent and +/-$500,000 are provided for 2018 actuals compared to the 2020 budget by FERC account in Volume 6, Budget Documentation, Variance Analysis. Explanations of variations of +/-10 percent on rate base items are provided with the schedules in Volume 3, Required Information, Section IV, Other Required Information, Tab 5, GAAP/FERC/COSS Comparison

3) Financial Labeling

In the Revenue Requirement Rebuttal Testimony in Docket E002/GR-12-961, the Company agreed to make efforts to label all costs and revenues to the relevant financial source: Xcel Energy Services, Inc.; NSP System; NSP-Minnesota or NSPM (Total Company – electric and gas utilities); NSPM Electric; and State of Minnesota Electric Jurisdiction. We have made a good faith effort to satisfy that commitment.

For reference, following is a list of the labels used and the definitions of each.

- Xcel Energy or XEI: The entire enterprise – XES, NSPM, NSPW, SPS, PSCo, and affiliate companies.
- XES: Xcel Energy Services: Xcel Energy's service company that provides services across all Xcel Energy affiliate companies.
- NSPM (Total Company): Northern States Power Company-Minnesota, providing service to electric and gas customers in Minnesota, North Dakota, and South Dakota.

- NSPW (Total Company): Northern States Power Company-Wisconsin, providing service to electric and gas customers in Wisconsin and Michigan.
- NSP System: The combined NSPM and NSPW electric production and transmission system.
- NSPM Electric: Northern States Power Company, including the portion allocated or direct assigned to the electric utility.
- State of Minnesota: Items physically located in the State of Minnesota such as distribution facilities or property taxes assessed by the State.
- State of Minnesota Electric Jurisdiction: Amounts direct assigned or allocated to the electric utility and to the State of Minnesota. Interchange Agreement billings to and from NSPW are reflected in revenues and expenses, respectively.
- State of Minnesota Electric Jurisdiction net of Interchange Agreement billings to NSPW or State of Minnesota Electric Jurisdiction, net of Interchange: The net amount allocated to the cost of service for electric customers in the State of Minnesota. The portion of the item billed to NSPW through the Interchange Agreement has been netted against the item to show the net impact to Minnesota electric customers.

Other Company witnesses provide amounts in their testimonies from several applicable financial sources. To the extent practicable, they have also provided the State of Minnesota jurisdictional amount. The jurisdictional amounts were developed under my guidance and are consistent with development of allocators as explained in the Cost Assignment and Allocation Manual presented by Ms. Schmidt as Schedule 3 to her Direct Testimony, and in Schedule 3, Cost of Service Study Summary to my Direct Testimony. In order to provide further context, an index to these financial sources is included as Exhibit___(BCH-1), Schedule 5, Labeling of Financial Sources.

4) Wholesale Customer Study

With respect to the costs and revenues related to services provided to wholesale customers, the Company and Department agreed as follows:

> The Company will provide as a compliance filing in future rate cases a wholesale customer study which shows all wholesale customers being served by the Company (including, but not limited to, full requirements, partial requirements, and market based wholesale customers), types of service being provided to each wholesale customer, costs and revenues associated with each wholesale customer, and a clear showing either that wholesale costs are allocated out of the retail rate case or that the revenues are included in the retail rate case, for all services provided to wholesale customers.[9]

Schedule 14, Wholesale Customer Study, provides the required information. The study does not address wholesale transmission revenues. Wholesale transmission revenues and associated costs are discussed in the Direct Testimony of Mr. Benson.

B. Decommissioning

A discussion of the Company's compliance history and the status of pending dockets with respect to nuclear decommissioning and the use of Department

[9] May 22, 2013 Issues List Page 19 in Docket No E002/GR-12-961.

of Energy payments is contained in Section VII. Triennial Nuclear Decommissioning Costs, of Ms. Wold's Direct Testimony.

C. Other Compliance Requirements

1) Incentive Compensation Refunds

In Docket No. E002/GR-10-971, the Commission required Xcel Energy to continue to refund all incentive compensation payments earned according to the Xcel Energy incentive compensation plan and recoverable in rates under the Order, but not paid. For 2018 (paid in March 2019), incentive plan payouts were at a level that required the Company to refund customers $1.8 million, as reported in our annual incentive compensation compliance filing in Docket Nos. E002/GR-92-1185, G002/GR-92-1186, and E,G002/M-19-376 on May 31, 2019. Our last rate case, which was based on a 2016 test year and escalated to a 2018 plan year, included the budgeted incentive compensation costs accrued in 2018 and payable in March 2019, after excluding certain costs (*e.g.*, executive long term incentive).

The 2020 test year includes the budgeted incentive compensation costs accrued in 2020 and payable in March 2021, after excluding certain costs (*e.g.*, executive long term incentive), which I identified in Section VII. B.4, Annual Adjustments to Test Year. As in the past, if the Company does not pay a level of incentive compensation at least equal to the amount of expense recovered in rates, the Company agrees to track and refund the difference to customers.

2) Non-Asset Based Trading Activities–Fully Allocated Cost Study and Incremental Cost Study

In Docket No. E002/GR-10-971, the Company was directed to file in its next rate case both an incremental and fully allocated cost study of its non-asset based trading activities. In Direct Testimony in Docket E002/GR-15-826, we requested that only a fully-allocated cost study be submitted in future rate cases, as the incremental study is not used to determine the level of costs to charge to this activity. No opposition was raised in those proceedings. Therefore, only the fully allocated cost study is provided with this testimony as Schedule 17, Non-Asset Based Trading Cost Study.

3) Nuclear Fuel Outage Costs

In Docket No. E002/GR-08-1065, the Company was directed to include an analysis of nuclear plant outage costs as shown in Exhibit 86 to the hearing record. The required information is included in Volume 4, Section VIII Adjustments, Tab P4-1. Volume 4 also includes schedules in support of the 2021 and 2022 Plan Year nuclear fuel outage costs. These schedules provide a determination of the Minnesota retail jurisdiction revenue requirements associated with the Nuclear Outage Deferral and Amortization method, as well as a comparison to the Direct Expense method for the MYRP Forecast.

4) Capacity Cost Report

In Docket No. E002/GR-08-1065, the Commission ordered the Company to describe NSP System short-term and long-term capacity costs by contract. The required information is attached as Exhibit___(BCH-1) Schedule 15, Capacity Cost Study, which is Trade Secret. The methodology for budgeting capacity costs for the 2020-2022 MYRP is similar to that described by Mr. David G. Horneck in his Direct Testimony from Docket No. E002/GR-10-971. Contracts with which NSPM has long-term obligations to purchase capacity remain the same as described in that docket. The Company anticipates that it can meet the expected Midcontinent Independent System Operator (MISO) capacity planning reserve requirements for the 2020 planning year from its current generation and long term purchased capacity contracts. Therefore, the Company does not expect to purchase short term capacity contracts for the 2020 test year.

5) Lobbyist Compensation

In Docket No. E002/GR-10-971, we agreed to include a report of the total compensation for employees engaged in lobbying with an explanation of the costs included and excluded in the rate request. This information is provided in the Direct Testimony of Mr. O'Hara.

6) North Dakota Income Tax Credits

In Docket No. E-002/M-15-805, the Company was instructed to share non-Minnesota state tax credits as follows:

> Northern States Power Company d/b/a Xcel Energy shall credit its Minnesota ratepayers for their proportionate share of used North Dakota Investment Tax Credits associated with the Courtenay Wind project, based on the pro-rata share of the costs of the Courtenay Wind project that is charged to Minnesota ratepayers.

The North Dakota state credit for North Dakota-located wind generation is the only non-Minnesota state credit utilized by NSPM. Due to the size of the credits available relative to the North Dakota state taxable income, it is anticipated that the utilization of these credits will be limited by taxable income and not specifically known until North Dakota state tax returns are filed. The potential for credits are primarily the result of the Border, Courtenay and Foxtail Wind Farms. Pursuant to the Commission's April 11, 2017 Order in Docket No. E002/M-17-818, we will include North Dakota investment tax credits (NDITCs) associated with the wind farms mentioned above in our calculation of the revenue requirements in the RES rider.

7) Capital True-Up

Continuing the capital true-up reporting from our last rate case, the Company will submit an annual compliance filing during the MYRP that calculates the prior-year actual plant-related base rate revenue requirements. This compliance filing will compare the actual capital-related revenue requirements (actuals) to the capital forecast revenue requirements (forecast), consistent with the 2018 Capital True-Up Report submitted on May 1, 2019 under Docket No. E002/GR-15-826.

8) Recurring Compliance Reporting Requirements

The following compliance requirements are of a recurring nature reported upon in each rate case:

a) Edison Electric Institute Spare Transformer Sharing Agreement

The Commission's Order in Docket No. E002/PA-06-1662 required the Company to report any sales or purchases of transformers made under the EEI Spare Transformer Sharing Agreement in its next rate case. Over the life of the program there have been no triggering events to initiate a transformer sale or purchase under the program. Therefore, Xcel Energy has not sold or purchased any transformers under this agreement.

b) Minnesota Emissions Allowance

In Docket No. E002/M-94-13, the Commission ordered deferred accounting for revenues from the sale of certain emission allowances until the Company's next general rate case, where the effects of then-new changes to the FERC Uniform System of Accounts could be examined. The Company has continued the deferral over several rate cases, but the accumulated unamortized deferred balance of emission sales is less than $4,000. Due to the small level in this account that has been accumulating since 2010 when the deferral was last resolved, combined with the limited market for these allowances, the Company is proposing to discontinue the deferral of emission allowances with no adjustment in this proceeding. Thus, there is no adjustment included in this filing.

c) Advantage Service (a/k/a HomeSmart)

In Docket No. E002/GR-91-1, the Company was directed to require NSP Advantage Service (now branded as Xcel Energy HomeSmart) to: 1) pay a return on the use of the Company's billing services asset; 2) compensate the Company for its personnel's referral time; and 3) compensate the Company for use of its mailing lists. The Company has complied with these requirements.

d) Liberty Paper

In Docket No. E002/M-93-1253, the Commission ordered the Company to segregate the cost of constructing a steam pipeline from Sherco to Liberty Paper, Inc. from utility rate base, and to record operating and maintenance expenses to non-utility operations. The Company has complied with these requirements.

e) Tax Benefit Transfer Leases

In Docket No. G002/GR-97-1606, the Company was directed to treat Tax Benefit Transfer (TBT) leases consistent with prior Commission approved methodology. There are no TBTs included in the MYRP.

f) Sale of Renewable Energy Credits

In Docket No. E002/GR-08-1065, the Company was directed to flow revenues from the sale of Renewable Energy Credits (RECs) through the RES Rider. A petition to pass certain RECs to customers using the FCA was approved by the Commission in Docket No. E002/M-12-1132. The Commission ordered the proceeds from the sale of RECs be returned to customers through the RES Rider unless the Commission makes a specific determination to allow a sharing of the proceeds. The Company has complied with this requirement.

g) Competitive Bidding

In Docket No. E002/M-95-174 the Company was permitted to offer Company-owned generation to compete against other provider offerings. The Company is required to track capacity-related non-performance penalties on NSP Generation projects for return to customers. We have incurred no such penalties.

X. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. I recommend that the Commission determine an overall 2020 retail revenue requirement of $3.3 billion and 2020 revenue deficiency of $201 million for the Company's Minnesota jurisdictional electric operation, determined by the cost of service for the 2020 test year. I also recommend a revenue deficiency for each year of the MYRP as follows:

Table 14

2020-2022 Revenue Requests

Minnesota Jurisdictional Costs Net of Interchange ($s in millions)

MYRP Year	2020	2021	2022
Amount, cumulative	$201.4	$347.8	$466.1
Amount, incremental	$201.4	$146.4	$118.3
Average % increase, incremental *	6.5%	4.8%	3.9%

* The average percent increase, incremental is calculated using the incremental revenue request over the forecasted present revenues in each applicable year.

Lastly, I also recommend the Commission grant a 2020 interim rate increase of $122.0 million, and an additional 2021 interim rate increase of $144.0 million, for the Company's Minnesota jurisdictional operation.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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 Minnesota Public Utilities Commission, the South Dakota Public Utilities Commission, and the North Dakota Public Service Commission, and the Federal Energy Regulatory Commission.

Prior Testimony

North Dakota - Advance Determination of Prudence for Dakota Range III Case N. PU-18-430
FERC – Interchange Agreement Annual Update, Docket No. ER19-1340-000, effective January 2019

Energy-Related Employment History

Xcel Energy – Minneapolis, MN

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

Education

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

SUMMARY OF REVENUE REQUIREMENTS
($000's)

Line	Description	Adjusted Proposed Test Year 2020	Adjusted Proposed Plan Year 2021	Adjusted Proposed Plan Year 2022
1	Average Rate Base	$8,986,901	$9,309,544	$9,805,740
2	Operating Income (Before AFUDC)	$497,145	$414,729	$366,852
3	Allowance for Funds Used During Construction	$28,846	$31,000	$33,500
4	Total Available for Return (Line 2 + Line 3 + Rounding)	$525,991	$445,729	$400,352
5	Overall Rate of Return (Line 4 / Line 1)	5.85%	4.79%	4.08%
6	Required Rate of Return	7.45%	7.45%	7.47%
7	Operating Income Requirement (Line 1 x Line 6)	$669,524	$693,561	$732,489
8	Income Deficiency (Line 7 - Line 4)	$143,533	$247,832	$332,137
9	Gross Revenue Conversion Factor	1.40335	1.40335	1.40335
10	Revenue Deficiency (Line 8 x Line 9)	$201,427	$347,795	$466,104
11	Retail Related Revenue Under Present Rates	$3,121,140	$3,080,944	$3,069,438
12	Revenue Requirements Under Proposed Rates	$3,322,566	$3,428,739	$3,535,542
13	Percentage Increase Needed in Overall Revenue (Line 10 / Line 11)	6.45%	11.29%	15.19%
14	Retail Related Revenue Under Present Rates EXCLUDING FUEL	$2,325,085	$2,284,889	$2,273,383
15	Percentage Increase Needed Excluding Fuel (Line 10 / Line 14)	8.66%	15.22%	20.50%

COST OF SERVICE SUMMARY for 2020-2022 MYRP FORECAST
($000s)

Line No.		Minnesota Electric Jurisdiction 2020 Test Year	2021 Plan Year	2022 Plan Year
1	**Composite Income Tax Rate**			
2	State Tax Rate	9.80%	9.80%	9.80%
3	Federal Statuatory Tax Rate	21.00%	21.00%	21.00%
4	Federal Effective Tax Rate	18.94%	18.94%	18.94%
5	**Composite Tax Rate**	**28.74%**	**28.74%**	**28.74%**
6	Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.403351	1.403351	1.403351
7				
8	**Weighted Cost of Capital**			
9	Active Rates and Ratios Version	Proposed	Proposed	Proposed
10	Cost of Short Term Debt	2.97%	2.99%	3.04%
11	Cost of Long Term Debt	4.42%	4.44%	4.48%
12	Cost of Common Equity	10.20%	10.20%	10.20%
13	Ratio of Short Term Debt	0.87%	1.22%	1.08%
14	Ratio of Long Term Debt	46.63%	46.28%	46.42%
15	Ratio of Common Equity	52.50%	52.50%	52.50%
16	Weighted Cost of STD	0.03%	0.04%	0.03%
17	Weighted Cost of LTD	2.06%	2.05%	2.08%
18	Weighted Cost of Debt	2.09%	2.09%	2.11%
19	Weighted Cost of Equity	5.36%	5.36%	5.36%
20	**Required Rate of Return**	**7.45%**	**7.45%**	**7.47%**
21				
22	**Rate Base**			
23	Plant Investment	19,958,469	20,817,953	21,700,191
24	Depreciation Reserve	9,295,420	10,004,539	10,641,880
25	Net Utility Plant	10,663,050	10,813,415	11,058,311
26	CWIP	363,989	417,804	507,890
27				
28	Accumulated Deferred Taxes	2,657,733	2,677,245	2,670,102
29	DTA - NOL Average Balance	(0)	(0)	(0)
31	DTA - Federal Tax Credit Average Balance	(356,731)	(489,606)	(654,397)
32	Total Accum Deferred Taxes	2,301,002	2,187,638	2,015,705
33				
34	Cash Working Capital	(119,149)	(127,030)	(140,888)
35	Materials and Supplies	153,932	153,932	153,932
36	Fuel Inventory	65,875	65,875	65,875
37	Non-plant Assets and Liabilities	60,475	81,070	90,346
38	Customer Advances	(9,797)	(9,797)	(9,797)
39	Customer Deposits	(54,826)	(54,826)	(54,826)
40	Prepaids and Other	68,747	67,952	68,129
41	Regulatory Amortizations	95,608	88,788	82,473
42	Total Other Rate Base Items	260,864	265,964	255,244
43				
44	**Total Rate Base**	**8,986,901**	**9,309,544**	**9,805,740**
45				

COST OF SERVICE SUMMARY for 2020-2022 MYRP FORECAST
($000s)

Line No.		Minnesota Electric Jurisdiction		
		2020 Test Year	2021 Plan Year	2022 Plan Year
46	**Operating Revenues**			
47	Retail	3,120,645	3,080,450	3,068,944
48	Interdepartmental	494	494	494
49	Other Operating Rev - Non-Retail	545,018	560,238	574,740
50	**Total Operating Revenues**	**3,666,158**	**3,641,182**	**3,644,178**
51				
52	**Expenses**			
53	Operating Expenses:			
54	Fuel	937,629	937,984	937,289
55	Deferred Fuel			
56	Variable IA Production Fuel			
57	Purchased Energy - Windsource	0	0	0
58	Fuel & Purchased Energy Total	937,629	937,984	937,289
59	Production - Fixed	419,439	431,090	430,921
60	Production - Fixed IA Investment			
61	Production - Fixed IA O&M	32,191	39,885	40,363
62	Production - Variable	6,023	6,338	6,704
63	Production - Variable IA O&M	16,285	15,635	16,433
64	Production - Purchased Demand	130,789	135,602	143,342
65	Production Total	604,726	628,551	637,764
66	Regional Markets	10,571	10,576	10,664
67	Transmission IA	107,247	112,621	119,784
68	Transmission	137,802	137,076	139,239
69	Distribution	114,249	132,140	127,086
70	Customer Accounting	48,973	48,931	43,907
71	Customer Service & Information	105,520	105,532	105,572
72	Sales, Econ Dvlp & Other	(6)	(5)	(5)
73	Administrative & General	246,966	252,269	260,301
74	**Total Operating Expenses**	**2,313,678**	**2,365,673**	**2,381,602**
75				
76	Depreciation	683,392	719,524	760,859
77	Amortization	43,948	43,475	44,757
78				
79	**Taxes:**			
80	Property Taxes	178,357	183,524	197,091
81	ITC Amortization	(1,223)	(1,223)	(1,222)
82	Deferred Taxes	23,496	590	(32,132)
83	Deferred Taxes - NOL			
84	Less State Tax Credits deferred			
85	Less Federal Tax Credits deferred	(93,712)	(172,039)	(157,543)
86	Deferred Income Tax & ITC	(71,438)	(172,672)	(190,897)
87	Payroll & Other Taxes	27,259	27,352	27,435
88	**Total Taxes Other Than Income**	**134,178**	**38,204**	**33,630**
89				

COST OF SERVICE SUMMARY for 2020-2022 MYRP FORECAST
($000s)

Line No.		Minnesota Electric Jurisdiction		
		2020 Test Year	2021 Plan Year	2022 Plan Year
90	**Income Before Taxes**			
91	Total Operating Revenues	3,666,158	3,641,182	3,644,178
92	less: Total Operating Expenses	2,313,678	2,365,673	2,381,602
93	Book Depreciation	683,392	719,524	760,859
94	Amortization	43,948	43,475	44,757
95	Taxes Other than Income	134,178	38,204	33,630
96	**Total Before Tax Book Income**	490,962	474,306	423,330
97				
98	**Tax Additions**			
99	Book Depreciation	683,392	719,524	760,859
100	Deferred Income Taxes and ITC	(71,438)	(172,672)	(190,897)
101	Nuclear Fuel Burn (ex. D&D)	105,136	102,794	107,318
102	Nuclear Outage Accounting	43,158	41,788	41,215
103	Avoided Tax Interest	10,700	12,433	15,172
104	Other Book Additions	5,656	5,656	5,656
105	**Total Tax Additions**	776,603	709,523	739,323
106				
107	**Tax Deductions**			
108	Total Rate Base	8,986,901	9,309,544	9,805,740
109	Weighted Cost of Debt	2.09%	2.09%	2.11%
110	Debt Interest Expense	187,826	194,569	206,901
111	Nuclear Outage Accounting	29,284	54,072	29,285
112	Tax Depreciation and Removals	997,042	930,357	886,793
113	NOL Utilized / (Generated)			
114	Other Tax / Book Timing Differences	11,855	3,725	(12,176)
115	**Total Tax Deductions**	**1,226,007**	**1,182,723**	**1,110,803**
116				
117	**State Taxes**			
118	State Taxable Income	41,558	1,106	51,850
119	State Income Tax Rate	9.80%	9.80%	9.80%
120	State Taxes before Credits	4,073	108	5,081
121	Less State Tax Credits applied	(1,195)	(1,195)	(1,195)
122	**Total State Income Taxes**	2,877	(1,087)	3,886
123				
124	**Federal Taxes**			
125	Federal Sec 199 Production Deduction			
126	Federal Taxable Income	38,680	2,193	47,964
127	Federal Income Tax Rate	21.00%	21.00%	21.00%
128	Federal Tax before Credits	8,123	461	10,072
129	Less Federal Tax Credits	(17,184)	60,203	42,520
130	**Total Federal Income Taxes**	(9,061)	60,663	52,592
131				
132	**Total Taxes**			
133	Total Taxes Other than Income	134,178	38,204	33,630
134	Total Federal and State Income Taxes	(6,184)	59,576	56,478
135	**Total Taxes**	127,994	97,781	90,108
136				
137	**Total Operating Revenues**	**3,666,158**	**3,641,182**	**3,644,178**
138	**Total Expenses**	**3,169,012**	**3,226,453**	**3,277,326**
139				
140	AFDC Debt	9,050	11,245	12,320
141	AFDC Equity	19,796	19,755	21,180
142				
143	**Net Income**	**525,991**	**445,729**	**400,352**

COST OF SERVICE SUMMARY for 2020-2022 MYRP FORECAST
($000s)

Line No.		Minnesota Electric Jurisdiction 2020 Test Year	2021 Plan Year	2022 Plan Year
144				
145	**Rate of Return (ROR)**			
146	Total Operating Income	525,991	445,729	400,352
147	Total Rate Base	8,986,901	9,309,544	9,805,740
148	**ROR (Operating Income / Rate Base)**	5.85%	4.79%	4.08%
149				
150	**Return on Equity (ROE)**			
151	Net Operating Income	525,991	445,729	400,352
152	Debt Interest (Rate Base * Weighted Cost of Debt)	(187,826)	(194,569)	(206,901)
153	Earnings Available for Common	338,165	251,160	193,451
154	Equity Rate Base (Rate Base * Equity Ratio)	4,718,123	4,887,511	5,148,014
155	**ROE (earnings for Common / Equity)**	7.17%	5.14%	3.76%
156				
157	**Revenue Deficiency**			
158	Required Operating Income (Rate Base * Required Return)	669,524	693,561	732,489
159	Net Operating Income	525,991	445,729	400,352
160	**Operating Income Deficiency**	143,533	247,832	332,137
161				
162	Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.403351	1.403351	1.403351
163	**Revenue Deficiency (Income Deficiency * Conversion Factor)**	**201,427**	**347,795**	**466,104**
164				
165	**Total Revenue Requirements**			
166	Total Retail Revenues	3,121,140	3,080,944	3,069,438
167	Revenue Deficiency	201,427	347,795	466,104
168	Total Revenue Requirements	3,322,566	3,428,739	3,535,542
169				
170				
171	**Excluding Fuel Clause Expense and Revenue**			
172	Base Cost of Energy	796,055	796,055	796,055
173	Line 137 - Total Operating Revenue	2,870,103	2,845,127	2,848,123
174	Line 138 - Total Operating Expense	2,372,958	2,430,398	2,481,271
175	Line 143 - Net Income	525,991	445,729	400,352
176	Change	0	0	0

CASH WORKING CAPITAL

Line No.	Summary Cash Working Capital		Lead/Lag Days	Minnesota Electric Jurisdiction 2020 Test Year Dollars	2020 Test Year Dollar x Days	2021 Plan Year Dollars	2021 Plan Year Dollar x Days	2022 Plan Year Dollars	2022 Plan Year Dollar x Days
1	**Fuel Expenses**								
2	Coal and Rail Transport		18.40	228,698	4,208,036	228,698	4,208,036	228,698	4,208,036
3	Gas for Generation		39.39	88,560	3,488,373	88,560	3,488,373	88,560	3,488,373
4	Oil		10.83	40	437	40	437	40	437
5	Nuclear and EOL			104,427	-	104,624	-	104,834	-
6	**Subtotal Fuel Expenses**			**421,725**	**7,696,845**	**421,922**	**7,696,845**	**422,132**	**7,696,845**
7	**Purchased Power**								
8	Purchases		39.59	631,643	25,006,744	636,456	25,197,288	644,196	25,503,700
9	Interchange		37.29	161,157	6,009,537	173,782	6,480,348	182,503	6,805,550
10	**SubTotal Purchased Power**			**792,800**	**31,016,281**	**810,238**	**31,677,636**	**826,699**	**32,309,250**
11	**Labor and Related**								
12	Regular Payroll		11.74	362,651	4,257,520	373,994	4,390,685	372,284	4,370,615
13	Incentive		250.47	14,759	3,696,575	15,201	3,807,473	15,657	3,921,695
14	Pension and Benefits		37.29	77,314	2,883,038	78,336	2,921,144	79,517	2,965,176
15	**SubTotal Labor and Related**			**454,723**	**10,837,133**	**467,531**	**11,119,302**	**467,458**	**11,257,486**
				-	-	-	-	-	-
16	All Other Operating Expenses		43.89	735,400	32,276,716	771,869	33,877,309	776,931	34,099,522
17	Property taxes		354.80	179,102	63,545,422	187,066	66,371,046	202,475	71,838,111
18	Employer's Payroll Taxes		31.05	27,259	846,380	27,352	849,267	27,435	851,869
19	Gross Earnings Tax		58.80	67,116	3,946,413	67,116	3,946,413	67,116	3,946,413
20	Federal Income Tax		34.50	(32,651)	(1,126,465)	(64,122)	(2,212,221)	(76,415)	(2,636,323)
21	State Income Tax		30.25	(8,687)	(262,795)	(31,507)	(953,087)	(20,373)	(616,296)
22	State Sales Tax Customer Billings		35.14	151,865	5,336,532	151,865	5,336,532	151,865	5,336,532
23	**Total Expenses**	A		**2,788,651**	**154,112,463**	**2,809,329**	**157,709,043**	**2,845,323**	**164,083,409**
24	Net Annual Expense			55.26	422,226	56.14	432,080	57.67	449,544
25	**Revenues**								
26	Retail Revenue		41.01	3,182,153	130,500,088	3,136,708	128,636,382	3,116,261	127,797,877
27	Late Payment		-	5,687		5,687		5,687	
28	Interdepartmental		-	494		494		494	
29	Misc Services		41.01	3,593	147,355	3,933	161,273	3,286	134,745
30	Rentals		(104.24)	4,982	(519,288)	5,006	(521,817)	5,006	(521,817)
31	Interchange		37.29	393,977	14,691,411	414,576	15,459,549	427,409	15,938,075
32	Retail Rev Lag Days		41.01	18,376	753,593	17,049	699,197	16,312	668,959
33	MISO		14.00	6,421	89,897	6,428	89,987	6,434	90,075
34	Wholesale Lag Days		28.63	202,231	5,789,877	204,100	5,843,389	211,973	6,068,788
35	**Total Revenues**	B		**3,817,914**	**151,452,933**	**3,793,981**	**150,367,961**	**3,792,862**	**150,176,701**
36	Net Annual Amount			39.67	414,940	39.63	411,967	39.59	411,443
37	Expense/Revenue Factor	C = A/B			73.041%		74.047%		75.018%
38	Allocated Revenue Amount	D = B * C			303,077		305,049		308,656
39	**Net Cash Working Capital**	E = D - A			**(119,149)**		**(127,030)**		**(140,888)**

LABELING OF FINANCIAL SOURCES

Xcel Energy or XEI
The entire enterprise – XES, NSPM, NSPW, SPS, PSCo, and affiliate companies.

XES: Xcel Energy Services
Xcel Energy's service company that provides services across all Xcel Energy affiliate companies.

NSPM (Total Company)
Northern States Power Company-Minnesota providing service to electric and gas customers in Minnesota, North Dakota, and South Dakota.

NSPW (Total Company)
Northern States Power Company-Wisconsin providing service to electric and gas customers in Wisconsin and Michigan.

NSP System
The combined NSPM and NSPW electric production and transmission system.

NSPM Electric
Northern States Power Company, including the portion allocated or direct assigned to the electric utility.

State of Minnesota
Items physically located in the State of Minnesota, such as distribution facilities or property taxes assessed by the State.

State of Minnesota Electric Jurisdiction
Amounts direct assigned or allocated to the electric utility and to the State of Minnesota. Interchange Agreement billings to and from NSPW are reflected in revenues and expenses, respectively.

State of Minnesota Electric Jurisdiction net of Interchange Agreement billings to NSPW
Or, State of Minnesota Electric Jurisdiction, net of Interchange
The net amount allocated to the cost of service for electric customers in the State of Minnesota. The portion of the item billed to NSPW through the Interchange Agreement has been netted against the item to show the net impact to Minnesota electric customers.

Notes:

1. Jurisdictional numbers will be provided where practicable.
2. The table below shows the typical financial basis from which the allocations are being made, unless otherwise specified.

Order	Topic	Witness	Financial Source
1	Policy / MYRP Policy	Chamberlain	NSPM Electric
2	MYRP	Liberkowski	State of MN Electric Jurisdiction
3	Performance Based Rates (PBR)	Ryan	N/A
4	Revenue Requirements	Halama	State of MN Electric Jurisdiction
5	Capital Structure	Soong	NSPM (Total Company)
6	Return on Equity	Reed	State of MN Electric Jurisdiction
7	Budgeting	Robinson	NSPM Electric
8	Cost Allocations	Schmidt	NSPM Electric
9	Sales Forecast	Marks	NSPM Electric
10	Nuclear Operations	O'Connor	NSPM Electric
11	Transmission	Benson	NSPM Electric
12	Energy Supply	Capra	NSPM Electric
13	Distribution	Bloch	NSPM Electric / State of MN Electric Jurisdiction
14	Business Systems	Harkness	NSPM (Total Company)
15	Customer Experience (AGIS Policy)	Gersack	NSPM (Total Company)
16	AGIS Costs/Benefits	Ravikrishna	NSPM (Total Company)
17	Insurance	Miller	XEI and NSPM (Total Company)
18	Compensation and Benefits	Lowenthal	Xcel Energy, NSPM (Total Company), and NSPM Electric
19	Pension	Schrubbe	State of MN Electric Jurisdiction
20	Pension Investments	Inglis	N/A
21	Employee Expenses	O'Hara	NSPM (Total Company)
22	Depreciation	Wold	NSPM Electric
23	Property Tax	Arend	NSPM (Total Company)
24	Customer Care/Bad Debt	Cardenas	NSPM Electric
25	CCOSS	Peppin	State of MN Electric Jurisdiction
26	Rate Design	Huso	State of MN Electric Jurisdiction
27	Decoupling	Huber	N/A

DETAILED CASE DRIVERS

Test Year Drivers - Revenue Requirements - Incremental
Amounts in millions
Increase / (Decrease)

Line No.	Description	2020 TY to 2019 MYRP Adjusted	2021 TY to 2020 TY Adjusted	2022 TY to 2021 TY Adjusted	3-Year MYRP Adjusted
	Capital and Capital Related				
1	Nuclear	$55.2	$3.0	$4.9	$63.1
2	Steam	(18.3)	2.6	4.4	(11.4)
3	Wind	77.0	4.6	(1.1)	80.5
4	All Other Production	2.9	3.8	2.6	9.3
5	Transmission	60.8	1.3	9.5	71.6
6	Distribution	22.8	19.9	32.2	74.9
7	General and Intangible	18.8	11.8	11.9	42.6
8	DTA (Federal Credits & NOL)	5.8	9.2	11.5	26.5
9	Other Rate Base	1.0	0.0	(0.8)	0.2
10	Cost of Capital	66.8	2.4	3.7	72.9
11	TOTAL Capital and Capital Related	$292.7	$58.7	$78.8	$430.3
12	Amortizations	$5.4	($0.0)	($2.0)	$3.5
	Taxes				
13	Taxes - Other	($5.7)	$6.8	$14.8	$16.0
14	PTCs	(67.1)	(0.9)	(3.2)	(71.2)
15	TCJA Impact	(107.5)	-	-	(107.5)
16	Property Tax	(20.4)	5.2	13.6	(1.7)
17	Payroll Tax	(2.6)	0.1	0.1	(2.5)
18	TOTAL Taxes	($203.3)	$11.2	$25.3	($166.9)
	Operating Expense				
19	Nuclear	($60.3)	$6.9	$2.3	($51.1)
20	Steam	(36.3)	3.2	(6.2)	(39.3)
21	Wind	7.1	1.8	3.8	12.7
22	Purchased Demand	2.3	4.8	7.7	14.8
23	All Other Production	7.7	7.1	1.6	16.4
24	Transmission	(1.7)	(1.6)	0.1	(3.1)
25	Transmission Interchange	(22.9)	5.4	7.2	(10.4)
26	Distribution	3.1	17.9	(5.1)	15.9
27	Regional Markets	3.3	0.0	0.1	3.4
28	Customer Accounting / Info / Service	(1.7)	(0.0)	(5.0)	(6.7)
29	A&G	22.5	5.3	8.0	35.9
30	TOTAL O&M	($76.9)	$50.8	$14.5	($11.6)
	Margins				
31	Sales Change	$94.3	$33.4	$7.3	$135.0
32	TCJA Refunds	107.5	-	-	107.5
34	Other Revenue	(18.3)	(7.7)	(5.7)	(31.7)
35	TOTAL Margins	$183.4	$25.7	$1.7	$210.8
36	TOTAL Net Incremental Deficiency	$201.4	$146.4	$118.3	$466.1

COMPARISON OF DETAILED RATE BASE COMPONENTS
Test Year Ending December 31, 2020
($000s)

Line No.	Description	General Rate Case Filing Docket No. E002/GR-15-826 (A)	General Rate Case Filing Docket No. E002/GR-19-564 Final Rates (B)	Change (C) = (B) - (A)
	Electric Plant as Booked			
1	Production	$10,060,608	$11,115,442	$1,054,834
2	Transmission	2,397,725	3,268,599	870,874
3	Distribution	3,658,370	3,883,261	224,891
4	General	888,530	940,887	52,357
5	Common	781,187	750,280	(30,907)
6	TOTAL Utility Plant in Service	$17,786,420	$19,958,469	2,172,049
	Reserve for Depreciation			
7	Production	$6,015,790	$6,326,757	$310,967
8	Transmission	619,062	728,387	109,325
9	Distribution	1,391,483	1,446,041	54,558
10	General	451,746	459,973	8,227
11	Common	412,713	334,261	(78,452)
12	TOTAL Reserve for Depreciation	$8,890,795	$9,295,420	$404,625
	Net Utility Plant in Service			
13	Production	$4,044,818	$4,788,685	$743,867
14	Transmission	$1,778,663	2,540,212	761,549
15	Distribution	$2,266,887	2,437,219	170,332
16	General	$436,784	480,914	44,130
17	Common	$368,473	416,019	47,546
18	Net Utility Plant in Service	$8,895,625	$10,663,050	$1,767,424
19	Utility Plant Held for Future Use	$0	$0	$0
20	Construction Work in Progress	$380,350	$363,989	($16,362)
21	Less: Accumulated Deferred Income Taxes	$2,302,072	$2,301,002	($1,071)
22	Cash Working Capital	($111,130)	($119,149)	($8,019)
	Other Rate Base Items:			
23	Materials and Supplies	$135,797	$153,932	$18,134
24	Fuel Inventory	73,476	65,875	(7,601)
25	Non-Plant Assets & Liabilities	27,456	60,475	33,018
26	Customer Advances	(5,562)	(9,797)	(4,235)
27	Interest on Customer Deposits	(28,127)	(54,826)	(26,698)
28	Prepaids and Other	85,941	68,747	(17,194)
29	Regulatory Amortizations	$50,579	95,608	45,029
30	Total Other Rate Base Items	$339,561	$380,013	$40,453
31	Total Average Rate Base	$7,202,334	$8,986,901	$1,784,567

RATE BASE SCHEDULES
Detailed Rate Base Components
($000s)

Line No.	Description	2020 Test Year Adjusted (1)	2021 Plan Year Adjusted (1)	2022 Plan Year Adjusted (1)
	Electric Plant as Booked			
1	Production	$11,115,442	$11,481,125	$11,673,805
2	Transmission	3,268,599	3,359,259	3,490,183
3	Distribution	3,883,261	4,136,381	4,500,875
4	General	940,887	1,010,202	1,080,459
5	Common	750,280	830,985	954,870
6	TOTAL Utility Plant in Service	$19,958,469	$20,817,953	$21,700,191
	Reserve for Depreciation			
7	Production	$6,326,757	$6,774,974	$7,136,281
8	Transmission	728,387	787,936	848,684
9	Distribution	1,446,041	1,519,172	1,597,559
10	General	459,973	520,017	582,722
11	Common	334,261	402,441	476,634
12	TOTAL Reserve for Depreciation	$9,295,420	$10,004,539	$10,641,880
	Net Utility Plant in Service			
13	Production	$4,788,685	$4,706,151	$4,537,524
14	Transmission	2,540,212	2,571,324	2,641,499
15	Distribution	2,437,219	2,617,209	2,903,316
16	General	480,914	490,186	497,737
17	Common	416,019	428,545	478,235
18	Net Utility Plant in Service	$10,663,050	$10,813,415	$11,058,311
19	Utility Plant Held for Future Use	$0	$0	$0
20	Construction Work in Progress	$363,989	$417,804	$507,890
21	Less: Accumulated Deferred Income Taxes	$2,301,002	$2,187,638	$2,015,705
22	Cash Working Capital	($119,149)	($127,030)	($140,888)
	Other Rate Base Items:			
23	Materials and Supplies	$153,932	$153,932	$153,932
24	Fuel Inventory	65,875	65,875	65,875
25	Non-Plant Assets & Liabilities	60,475	81,070	90,346
26	Customer Advances	(9,797)	(9,797)	(9,797)
27	Interest on Customer Deposits	(54,826)	(54,826)	(54,826)
28	Prepaids and Other	68,747	67,952	68,129
29	Regulatory Amortizations	95,608	88,788	82,473
30	Total Other Rate Base Items	$380,013	$392,994	$396,132
31	Total Average Rate Base	$8,986,901	$9,309,544	$9,805,740

(1) Revenues and expenses for Transmission Cost Recovery (TCR) rider have been excluded.

STATEMENT OF OPERATING INCOME
2019 Final Compliance versus 2020 Test Year
($000s)

Line No.	Description	General Rate Case Filing E002/GR-15-826 Final Rates	General Rate Case Filing E002/GR-19-564 Test Year	Change
		(A)	(B)	(C) = (B) - (A)
	Operating Revenues			
1	Retail	3,051,778	3,120,645	$68,868
3	Interdepartmental	672	494	(178)
4	Other Operating	687,000	545,018	(141,982)
5	Gross Earnings Tax	0	0	0
6	**Total Operating Revenues**	$3,739,450	$3,666,158	($73,292)
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	$1,125,206	$937,629	($187,577)
8	Power Production	691,533	604,726	(86,807)
9	Transmission	243,697	255,621	11,924
10	Distribution	111,186	114,249	3,063
11	Customer Accounting	50,555	48,973	(1,582)
12	Customer Service & Information	95,067	105,520	10,454
13	Sales, Econ Dvlp & Other	69	(6)	(75)
14	Administrative & General	224,433	246,966	22,534
15	Total Operating Expenses	$2,541,744	$2,313,678	($228,065)
16	Depreciation	$568,522	$683,392	$114,870
17	Amortizations	21,871	43,948	22,077
	Taxes:			
18	Property	$198,796	$178,357	($20,439)
19	Gross Earnings	0	0	0
20	Deferred Income Tax & ITC	107,334	(71,438)	(178,772)
21	Federal & State Income Tax	(67,264)	(6,184)	61,081
22	Payroll & Other	29,896	27,259	(2,637)
23	Total Taxes	$268,761	$127,994	($140,767)
24	**Total Expenses**	$3,400,898	$3,169,012	($231,886)
25	AFUDC	$27,894	$28,846	$952
26	**Total Operating Income**	$366,445	$525,991	$159,546

Note: Revenues reflect calendar month sales.

STATEMENT OF OPERATING INCOME
2020 Test Year, 2021-2022 Plan Years
($000s)

Line No.	Description	2020 Test Year (A)	2021 Plan Year (B)	2022 Plan Year (C)
	Operating Revenues			
1	Retail	3,120,645	3,080,450	$3,068,944
3	Interdepartmental	494	494	494
4	Other Operating	545,018	560,238	574,740
5	Gross Earnings Tax	0	0	0
6	**Total Operating Revenues**	$3,666,158	$3,641,182	$3,644,178
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	$937,629	$937,984	$937,289
8	Power Production	604,726	628,551	637,764
9	Transmission	255,621	260,272	269,688
10	Distribution	114,249	132,140	127,086
11	Customer Accounting	48,973	48,931	43,907
12	Customer Service & Information	105,520	105,532	105,572
13	Sales, Econ Dvlp & Other	(6)	(5)	(5)
14	Administrative & General	246,966	252,269	260,301
15	Total Operating Expenses	$2,313,678	$2,365,673	$2,381,602
16	Depreciation	$683,392	$719,524	$760,859
17	Amortizations	43,948	43,475	44,757
	Taxes:			
18	Property	$178,357	$183,524	$197,091
19	Gross Earnings	0	0	0
20	Deferred Income Tax & ITC	(71,438)	(172,672)	(190,897)
21	Federal & State Income Tax	(6,184)	59,576	56,478
22	Payroll & Other	27,259	27,352	27,435
23	Total Taxes	$127,994	$97,781	$90,108
24	**Total Expenses**	$3,169,012	$3,226,453	$3,277,326
25	AFUDC	$28,846	$31,000	$33,500
26	**Total Operating Income**	$525,991	$445,729	$400,352

Note: Revenues reflect calendar month sales.

Northern States Power Company

RATE BASE SCHEDULES

Detailed Rate Base Components

($000s)

		Proposed Test Year 2020					
		Total Utility			Minnesota Jurisdiction		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Adjusted (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	Adjusted (F) (D) + (E)
	Electric Plant as Booked						
1	Production	$13,956,816	($1,084,037)	$12,872,778	$12,114,337	($998,895)	$11,115,442
2	Transmission	3,773,349	(12,781)	3,760,568	3,281,379	(12,781)	3,268,599
3	Distribution	4,439,012	0	4,439,012	3,883,261	0	3,883,261
4	General	1,101,039	(17,721)	1,083,317	958,608	(17,721)	940,887
5	Common	861,661	0	861,661	750,280	0	750,280
6	TOTAL Utility Plant in Service	$24,131,876	($1,114,539)	$23,017,336	$20,987,865	($1,029,396)	$19,958,469
	Reserve for Depreciation						
7	Production	$7,299,546	($18,846)	$7,280,700	$6,343,405	($16,647)	$6,326,757
8	Transmission	859,966	(10)	859,956	728,397	(10)	728,387
9	Distribution	1,632,155	0	1,632,155	1,446,041	0	1,446,041
10	General	529,865	(1,072)	528,793	461,045	(1,072)	459,973
11	Common	383,872	0	383,872	334,261	0	334,261
12	TOTAL Reserve for Depreciation	$10,705,404	($19,928)	$10,685,476	$9,313,149	($17,729)	$9,295,420
	Net Utility Plant in Service						
13	Production	$6,657,270	($1,065,191)	$5,592,079	$5,770,932	($982,248)	$4,788,685
14	Transmission	2,913,383	(12,771)	2,900,612	2,552,983	(12,771)	2,540,212
15	Distribution	2,806,857	0	2,806,857	2,437,219	0	2,437,219
16	General	571,173	(16,649)	554,525	497,562	(16,648)	480,914
17	Common	477,789	0	477,789	416,019	0	416,019
18	Net Utility Plant in Service	$13,426,471	($1,094,611)	$12,331,861	$11,674,717	($1,011,667)	$10,663,050
19	Utility Plant Held for Future Use	$0	$0	$0	$0	$0	$0
20	Construction Work in Progress	$597,512	($157,555)	$439,957	$521,530	($157,542)	$363,989
21	Less: Accumulated Deferred Income Taxes	$2,596,303	$19,561	$2,615,864	$2,283,455	$17,547	$2,301,002
22	Cash Working Capital	($145,597)	$12,391	($133,206)	($129,815)	$10,666	($119,149)
	Other Rate Base Items:						
23	Materials and Supplies	$176,908	$0	$176,908	$153,932	$0	$153,932
24	Fuel Inventory	75,984	0	75,984	65,875	0	65,875
25	Non-Plant Assets & Liabilities	72,003	0	72,003	60,475	0	60,475
26	Customer Advances	(11,777)	0	(11,777)	(9,797)	0	(9,797)
27	Interest on Customer Deposits	(54,994)	0	(54,994)	(54,826)	0	(54,826)
28	Prepaids and Other	79,092	0	79,092	68,747	0	68,747
29	Regulatory Amortizations	0	104,360	104,360	0	95,608	95,608
33	Total Other Rate Base Items	$337,216	$104,360	$441,577	$284,405	$95,608	$380,013
34	Total Average Rate Base	$11,619,300	($1,154,975)	$10,464,325	$10,067,382	($1,080,481)	$8,986,901

RATE BASE SCHEDULES
Detailed Rate Base Components
($000s)

		Adjusted (1) Plan Year 2021		Adjusted (1) Plan Year 2022	
Line No.	Description	Total Utility (A)	Minnesota Jurisdiction (B)	Total Utility (C)	Minnesota Jurisdiction (D)
	Electric Plant as Booked				
1	Production	$13,380,594	$11,481,125	$13,621,180	$11,673,805
2	Transmission	3,871,783	3,359,259	4,027,285	3,490,183
3	Distribution	4,707,724	4,136,381	5,104,737	4,500,875
4	General	1,165,338	1,010,202	1,246,268	1,080,459
5	Common	954,347	830,985	1,096,625	954,870
6	TOTAL Utility Plant in Service	$24,079,786	$20,817,953	$25,096,095	$21,700,191
	Reserve for Depreciation				
7	Production	$7,800,210	$6,774,974	$8,223,319	$7,136,281
8	Transmission	928,483	787,936	998,538	848,684
9	Distribution	1,715,984	1,519,172	1,805,026	1,597,559
10	General	598,133	520,017	670,608	582,722
11	Common	462,172	402,441	547,379	476,634
12	TOTAL Reserve for Depreciation	$11,504,982	$10,004,539	$12,244,870	$10,641,880
	Net Utility Plant in Service				
13	Production	$5,580,384	$4,706,151	$5,397,861	$4,537,524
14	Transmission	2,943,300	2,571,324	3,028,747	2,641,499
15	Distribution	2,991,741	2,617,209	3,299,711	2,903,316
16	General	567,205	490,186	575,660	497,737
17	Common	492,175	428,545	549,246	478,235
18	Net Utility Plant in Service	$12,574,804	$10,813,415	$12,851,225	$11,058,311
19	Utility Plant Held for Future Use	$0	$0	$0	$0
20	Construction Work in Progress	$483,557	$417,804	$579,001	$507,890
21	Less: Accumulated Deferred Income Taxes	$2,493,929	$2,187,638	$2,310,566	$2,015,705
22	Cash Working Capital	($141,786)	($127,030)	($157,026)	($140,888)
	Other Rate Base Items:				
23	Materials and Supplies	$176,908	$153,932	$176,908	$153,932
24	Fuel Inventory	75,984	65,875	75,984	65,875
25	Non-Plant Assets & Liabilities	94,015	81,070	103,791	90,346
26	Customer Advances	(11,777)	(9,797)	(11,777)	(9,797)
27	Interest on Customer Deposits	(54,994)	(54,826)	(54,994)	(54,826)
28	Prepaids and Other	78,189	67,952	78,396	68,129
29	Regulatory Amortizations	97,114	88,788	90,371	82,473
30	Total Other Rate Base Items	$455,439	$392,994	$458,680	$396,132
31	Total Average Rate Base	$10,878,085	$9,309,544	$11,421,314	$9,805,740

(1) Revenues and expenses for Transmission Cost Recovery (TCR) rider have been excluded.

COMPARISON OF DETAILED RATE BASE COMPONENTS: CWIP
Test Year Ending December 31, 2020
($000s)

Line No.	Description	Proposed Test Year 2020					
		Total Utility			Minnesota Jurisdiction *		
		Unadjusted (A)	Adjustments (B)	Total (A) + (B)	Unadjusted (D)	Adjustments (E)	Total (D) + (E)
	Construction Work in Progress						
1	Production	$396,032	($121,645)	$274,387	$343,148	($121,632)	$221,516
2	Transmission	77,174	(22,813)	54,361	67,081	(22,813)	44,269
3	Distribution	42,674	0	42,674	40,228	0	40,228
4	General	38,032	(13,097)	24,935	33,110	(13,097)	20,013
5	Common	43,599	0	43,599	37,964	0	37,964
6	TOTAL Construction Work In Progress	$597,512	($157,555)	$439,957	$521,530	($157,542)	$363,989

Line No.	Description	Plan Year 2021					
		Total Utility			Minnesota Jurisdiction *		
		Unadjusted (A)	Adjustments (B)	Total (A) + (B)	Unadjusted (D)	Adjustments (E)	Total (D) + (E)
	Construction Work in Progress						
7	Production	$269,424	($32,488)	$236,936	$233,855	($32,486)	$201,369
8	Transmission	105,259	(16,361)	88,899	91,578	(16,361)	75,217
9	Distribution	66,302	0	66,302	61,610	0	61,610
10	General	24,211	57	24,268	21,079	57	21,135
11	Common	67,152	0	67,152	58,472	0	58,472
12	TOTAL Construction Work In Progress	$532,349	($48,792)	$483,557	$466,594	($48,791)	$417,804

Line No.	Description	Plan Year 2022					
		Total Utility			Minnesota Jurisdiction *		
		Unadjusted (A)	Adjustments (B)	Total (A) + (B)	Unadjusted (D)	Adjustments (E)	Total (D) + (E)
	Construction Work in Progress						
13	Production	$271,567	($686)	$270,881	$236,223	($686)	$235,537
14	Transmission	132,258	0	132,258	115,059	0	115,059
15	Distribution	69,535	0	69,535	64,700	0	64,700
16	General	44,713	59	44,772	38,935	59	38,994
17	Common	61,555	0	61,555	53,599	0	53,599
18	TOTAL Construction Work In Progress	$579,629	($627)	$579,001	$508,517	($627)	$507,890

(*) See Volume 3, Rate Base Section, Schedule E for allocation factors.

COMPARISON OF DETAILED RATE BASE COMPONENTS: ADIT
Test Year Ending December 31, 2020
($000s)

		Proposed Test Year 2020					
		Total Utility			Minnesota Jurisdiction *		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Total (A) + (B)	Unadjusted (D)	Adjustments (E)	Total (D) + (E)
	Accumulated Deferred Income Taxes						
1	Production	$1,343,262	$5,189	$1,348,452	$1,164,648	$6,508	$1,171,157
2	Transmission	810,198	5,783	815,981	710,085	7,549	717,634
3	Distribution	694,763	(4,722)	690,041	610,533	(6,391)	604,142
4	General	88,746	(1,897)	86,849	78,058	(2,359)	75,699
5	Common	75,702	(249)	75,454	66,028	(326)	65,702
6	Net Operating Loss (NOL)	(442,699)	15,456	(427,243)	(369,297)	12,565	(356,731)
7	Non-Plant Related	26,330	0	26,330	23,399	0	23,399
8	TOTAL Accum Deferred Income Taxes	$2,596,303	$19,561	$2,615,864	$2,283,455	$17,547	$2,301,002

		Plan Year 2021					
		Total Utility			Minnesota Jurisdiction *		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Total (A) + (B)	Unadjusted (D)	Adjustments (E)	Total (D) + (E)
	Accumulated Deferred Income Taxes						
9	Production	$1,426,253	($51,082)	$1,375,171	$1,261,328	($74,098)	$1,187,230
10	Transmission	805,491	22,605	828,096	884,280	(156,136)	728,144
11	Distribution	697,516	(17,295)	680,222	475,003	120,343	595,346
12	General	90,459	(5,849)	84,610	48,365	25,192	73,558
13	Common	78,981	(4,430)	74,551	34,468	30,448	64,916
14	Net Operating Loss (NOL)	(613,490)	33,387	(580,103)	(517,285)	27,678	(489,606)
15	Non-Plant Related	31,382	0	31,382	28,051	0	28,051
16	TOTAL Accum Deferred Income Taxes	$2,516,592	($22,663)	$2,493,929	$2,214,211	($26,573)	$2,187,638

		Plan Year 2022					
		Total Utility			Minnesota Jurisdiction *		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Total (A) + (B)	Unadjusted (D)	Adjustments (E)	Total (D) + (E)
	Accumulated Deferred Income Taxes						
17	Production	$1,508,336	($131,176)	$1,377,160	$1,308,263	($129,244)	$1,179,019
18	Transmission	846,263	(7,618)	838,645	743,207	(6,020)	737,187
19	Distribution	670,646	2,403	673,049	587,311	1,747	589,058
20	General	85,644	(2,759)	82,885	74,826	(3,015)	71,812
21	Common	72,903	30	72,933	63,484	23	63,506
22	Net Operating Loss (NOL)	(807,234)	40,138	(767,096)	(687,629)	33,232	(654,397)
23	Non-Plant Related	32,990	0	32,990	29,519	0	29,519
24	TOTAL Accum Deferred Income Taxes	$2,409,547	($98,981)	$2,310,566	$2,118,982	($103,277)	$2,015,705

(*) See Volume 3, Rate Base Section, Schedule E for allocation factors.

Northern States Power Company

Docket No. E002/GR-19-564
Exhibit___(BCH-1), Schedule 10a

RATE BASE SCHEDULES
RATE BASE ADJUSTMENT SCHEDULES
2020 Unadjusted Test Year versus Final Adjusted Test Year
($000s)

Line No.	Description	Base				Adjustment	Amortization					Rider Removals		Secondary Calculations				Total
		Unadjusted w/o NOL & 199 Unadjusted	ADIT Prorate for IRS	Unadjusted NOL & 199	Total Unadjusted	Mankato Energy	Aurora	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Sherco 3 Depr Deferral	Rider: RES	Rider: TCR	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss	
	Work Paper Reference					WP A-22	WP A-33	WP A-34	WP A-35	WP A-36	WP A-38	WP A-40	WP A-41	WP A-43	WP A-44	WP A-46	WP A-45	
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
1	Plant as booked																	
2	Production	12,114,337			12,114,337	(569,751)						(429,143)						11,115,442
3	Transmission	3,281,379			3,281,379							(10,929)	(1,851)					3,268,599
4	Distribution	3,883,261			3,883,261													3,883,261
5	General	958,608			958,608								(17,721)					940,887
6	Common	750,280			750,280													750,280
7	Total Utility Plant in Service	20,987,865			20,987,865	(569,751)						(440,073)	(19,573)					19,958,469
8																		
9	Reserve for Depreciation																	
10	Production	6,343,405			6,343,405	(14,716)						(1,931)						6,326,757
11	Transmission	728,397			728,397							(10)						728,387
12	Distribution	1,446,041			1,446,041													1,446,041
13	General	461,045			461,045								(1,072)					459,973
14	Common	334,261			334,261													334,261
15	Total Reserve for Depreciation	9,313,149			9,313,149	(14,716)						(1,940)	(1,072)					9,295,420
16																		
17	Net Utility Plant																	
18	Production	5,770,932			5,770,932	(555,035)						(427,213)						4,788,685
19	Transmission	2,552,983			2,552,983							(10,920)	(1,851)					2,540,212
20	Distribution	2,437,219			2,437,219													2,437,219
21	General	497,563			497,563								(16,649)					480,914
22	Common	416,019			416,019													416,019
23	Net Utility Plant in Service	11,674,717			11,674,717	(555,035)						(438,132)	(18,500)					10,663,050
24																		
25	Utility Plant Held for Future Use																	
26																		
27	Construction Work in Progress	521,530			521,530	(88)						(131,463)	(25,991)					363,989
28																		
29	Less: Accumulated Deferred Income Taxes	2,521,395	(18,918)	(219,022)	2,283,455	(7,566)				16,310	2,977	(19,635)	(719)	13,615			12,565	2,301,002
30																		
31	Other Rate Base Items																	
32	Cash Working Capital	(129,815)			(129,815)										10,666			(119,149)
33	Materials and Supplies	153,932			153,932													153,932
34	Fuel Inventory	65,875			65,875													65,875
35	Non Plant Assets and Liabilities	60,475			60,475													60,475
36	Customer Advances	(9,797)			(9,797)													(9,797)
37	Customer Deposits	(54,826)			(54,826)													(54,826)
38	Prepayments	68,747			68,747													68,747
39	Regulatory Amortizations						1,488	419	46,509	39,896	7,295							95,608
40	Total Other Rate Base	154,590			154,590		1,488	419	46,509	39,896	7,295				10,666			260,864
41																		
42	Total Average Rate Base	9,829,442	18,918	219,022	10,067,382	(547,556)	1,488	419	46,509	23,587	4,319	(549,960)	(43,772)	(13,615)	10,666		(12,565)	8,986,901

Northern States Power Company

Docket No. E002/GR-19-564
Exhibit___(BCH-1), Schedule 10b

RATE BASE SCHEDULES
RATE BASE ADJUSTMENT SCHEDULES
2021 Unadjusted Test Year versus Final Adjusted 2021 Plan Year
($000s)

Line No.	Description	Base				Adjustment	Amortization					Rider Removals		Secondary Calculations				2021 Plan Year
		Unadjusted w/o NOL & 199 Unadjusted	ADIT Prorate for IRS	Unadjusted NOL & 199	Total Unadjusted	Mankato Energy	Aurora	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Sherco 3 Depr Deferral	Rider: RES	Rider: TCR	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss	
	Work Paper Reference					**WP A-22**	**WP A-33**	**WP A-34**	**WP A-35**	**WP A-36**	**WP A-38**	**WP A-40**	**WP A-41**	**WP A-43**	**WP A-44**	**WP A-46**	**WP A-45**	
1		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
2	Plant as booked																	
3	Production	13,030,270			13,030,270	(572,869)						(976,276)						11,481,125
4	Transmission	3,417,466			3,417,466							(31,312)	(26,894)					3,359,259
5	Distribution	4,136,381			4,136,381													4,136,381
6	General	1,044,195			1,044,195								(33,992)					1,010,202
7	Common	830,985			830,985													830,985
8	Total Utility Plant in Service	22,459,297			22,459,297	(572,869)						(1,007,589)	(60,887)					20,817,953
9																		
10	Reserve for Depreciation																	
11	Production	6,830,940			6,830,940	(33,129)						(22,837)						6,774,974
12	Transmission	788,218			788,218							(260)	(22)					787,936
13	Distribution	1,519,172			1,519,172													1,519,172
14	General	523,622			523,622								(3,605)					520,017
15	Common	402,441			402,441													402,441
16	Total Reserve for Depreciation	10,064,393			10,064,393	(33,129)						(23,097)	(3,628)					10,004,539
17																		
18	Net Utility Plant																	
19	Production	6,199,330			6,199,330	(539,740)						(953,439)						4,706,151
20	Transmission	2,629,248			2,629,248							(31,052)	(26,872)					2,571,324
21	Distribution	2,617,209			2,617,209													2,617,209
22	General	520,573			520,573								(30,387)					490,186
23	Common	428,545			428,545													428,545
24	Net Utility Plant in Service	12,394,904			12,394,904	(539,740)						(984,491)	(57,259)					10,813,415
25																		
26	Utility Plant Held for Future Use																	
27																		
28	Construction Work in Progress	466,594			466,594	(10)						(37,113)	(11,668)					417,804
29																		
30	Less: Accumulated Deferred Income Taxes	2,754,586	(23,090)	(517,285)	2,214,211	(13,551)				15,131	2,771	(79,565)	(2,504)	23,467			27,678	2,187,638
31																		
32	Other Rate Base Items																	
33	Cash Working Capital	(139,445)			(139,445)										12,415			(127,030)
34	Materials and Supplies	153,932			153,932													153,932
35	Fuel Inventory	65,875			65,875													65,875
36	Non Plant Assets and Liabilities	81,070			81,070													81,070
37	Customer Advances	(9,797)			(9,797)													(9,797)
38	Customer Deposits	(54,826)			(54,826)													(54,826)
39	Prepayments	67,952			67,952													67,952
40	Regulatory Amortizations						492	252	44,240	37,012	6,792							88,788
41	Total Other Rate Base	164,760			164,760		492	252	44,240	37,012	6,792				12,415			265,964
42																		
43	Total Average Rate Base	10,271,673	23,090	517,285	10,812,048	(526,198)	492	252	44,240	21,882	4,021	(942,039)	(66,423)	(23,467)	12,415		(27,678)	9,309,544

RATE BASE SCHEDULES
RATE BASE ADJUSTMENT SCHEDULES
2022 Unadjusted Test Year versus Final Adjusted 2022 Plan Year
($000s)

Line No.	Description	Base				Adjustment	Amortization					Rider Removals		Secondary Calculations				
		Unadjusted w/o NOL & 199 Unadjusted	ADIT Prorate for IRS	Unadjusted NOL & 199	Total Unadjusted	Mankato Energy	Aurora	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Sherco 3 Depr Deferral	Rider: RES	Rider: TCR	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss	2022 Plan Year
	Work Paper Reference					WP A-22	WP A-33	WP A-34	WP A-35	WP A-36	WP A-38	WP A-40	WP A-41	WP A-43	WP A-44	WP A-46	WP A-45	
1		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
2	Plant as booked																	
3	Production	13,342,206			13,342,206	(576,195)						(1,092,206)						11,673,805
4	Transmission	3,582,112			3,582,112							(40,767)	(51,162)					3,490,183
5	Distribution	4,500,875			4,500,875													4,500,875
6	General	1,116,125			1,116,125								(35,666)					1,080,459
7	Common	954,870			954,870													954,870
8	Total Utility Plant in Service	23,496,188			23,496,188	(576,195)						(1,132,973)	(86,829)					21,700,191
9																		
10	Reserve for Depreciation																	
11	Production	7,253,560			7,253,560	(51,628)						(65,650)						7,136,281
12	Transmission	850,218			850,218							(944)	(590)					848,684
13	Distribution	1,597,559			1,597,559													1,597,559
14	General	589,371			589,371								(6,649)					582,722
15	Common	476,634			476,634													476,634
16	Total Reserve for Depreciation	10,767,342			10,767,342	(51,628)						(66,594)	(7,239)					10,641,880
17																		
18	Net Utility Plant																	
19	Production	6,088,646			6,088,646	(524,567)						(1,026,556)						4,537,524
20	Transmission	2,731,894			2,731,894							(39,823)	(50,572)					2,641,499
21	Distribution	2,903,316			2,903,316													2,903,316
22	General	526,754			526,754								(29,018)					497,737
23	Common	478,235			478,235													478,235
24	Net Utility Plant in Service	12,728,846			12,728,846	(524,567)						(1,066,378)	(79,590)					11,058,311
25																		
26	Utility Plant Held for Future Use																	
27																		
28	Construction Work in Progress	508,517			508,517	(1)						(685)	59					507,890
29																		
30	Less: Accumulated Deferred Income Taxes	2,815,347	(8,736)	(687,629)	2,118,982	(18,741)				13,952	2,566	(146,990)	(4,758)	17,463			33,232	2,015,705
31																		
32	Other Rate Base Items																	
33	Cash Working Capital	(154,456)			(154,456)										13,568			(140,888)
34	Materials and Supplies	153,932			153,932													153,932
35	Fuel Inventory	65,875			65,875													65,875
36	Non Plant Assets and Liabilities	90,346			90,346													90,346
37	Customer Advances	(9,797)			(9,797)													(9,797)
38	Customer Deposits	(54,826)			(54,826)													(54,826)
39	Prepayments	68,129			68,129													68,129
40	Regulatory Amortizations							84	41,972	34,128	6,289							82,473
41	Total Other Rate Base	159,203			159,203			84	41,972	34,128	6,289				13,568			255,244
42																		
43	Total Average Rate Base	10,581,220	8,736	687,629	11,277,585	(505,827)		84	41,972	20,177	3,723	(920,073)	(74,773)	(17,463)	13,568		(33,232)	9,805,740

2020 TEST YEAR INCOME STATEMENT
ADJUSTMENT SCHEDULE

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
							WP-A1 - A15	WP-A16	WP-A17	WP-A18	WP-A19 - A21	WP-A22 - A23	WP-A24	WP-A25	WP-A26	WP-A27	WP-A28	WP-A29	WP-A30	WP-A31
			Unadjusted Secondary Calcs			Base	Precedential	Adjustment												
Line No.	NSPM - 11 Bridge by Report Label - Income Statement	Unadjusted	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Final Unadjusted	Precedential Adjustments	CIP Approved Program Levels	CIP Incentive	IA ROE	Incentive Compensation	Mankato Energy as PPA	Pension: Active Healthcare	Pension: Deferred Amort	Pension: Discount Rate	Pension: Non Qualified	Pension: Retiree Medical	Trading: Asset-Based Margin	Trading: Non Asset-Based Admin	Trading: Non Asset-Based Margin
1																				
2	Operating Revenues																			
3	Retail Revenue	3,197,649				3,197,649		(15,496)												
4	Interdepartmental	494				494														
5	Other Operating	765,610				765,610	14,021		15,033	(8,285)		(4,590)						(108,280)		(13,649)
6	Total Revenue	3,963,753				3,963,753	14,021	(15,496)	15,033	(8,285)		(4,590)						(108,280)		(13,649)
7																				
8	Expenses																			
9	Operating Expenses																			
10	Fuel & Purchased Energy	1,062,005				1,062,005												(103,457)		(6,918)
11	Power Production	563,360				563,360	(16)			(5,434)	(3,728)	50,713								
12	Transmission	354,649				354,649														
13	Distribution	114,249				114,249														
14	Customer Accounting	48,973				48,973														
15	Customer Service and Information	95,818				95,818		(15,496)	25,373											
16	Sales, Econ Dev, & Other						(6)													
17	Administrative and General	262,005				262,005	(5,474)				(11,527)		(1,524)	5,882	66	(875)	207		(1,793)	
18	Total Operating Expenses	2,501,059				2,501,059	(5,495)	(15,496)	25,373	(5,434)	(15,255)	50,713	(1,524)	5,882	66	(875)	207	(103,457)	(1,793)	(6,918)
19																				
20	Depreciation	707,973				707,973						(18,606)								
21	Amortization	34,361				34,361														
22																				
23	Taxes																			
24	Property	179,102				179,102														
25	Deferred Income Tax and ITC	74,987			(103,482)	(28,495)						(6,335)								
26	Federal and State Income Tax	(138,396)	(122)	840	102,066	(35,614)	5,618	(0)	(2,972)	(819)	4,385	(539)	438	(1,690)	(19)	252	(60)	(1,386)	515	(1,934)
27	Payroll and Other	27,290				27,290	(32)													
28	Total Taxes	142,983	(122)	840	(1,416)	142,283	5,587	(0)	(2,972)	(819)	4,385	(6,874)	438	(1,690)	(19)	252	(60)	(1,386)	515	(1,934)
29																				
30	Total Expenses	3,386,376	(122)	840	(1,416)	3,385,676	91	(15,496)	22,401	(6,253)	(10,871)	25,232	(1,086)	4,191	47	(624)	148	(104,844)	(1,278)	(8,853)
31																				
32	Allowance for Funds Used During Constru	28,853				28,853						(7)								
33																				
34	Net Income	606,231	122	(840)	1,416	606,930	13,930	(0)	(7,368)	(2,032)	10,871	(29,829)	1,086	(4,191)	(47)	624	(148)	(3,437)	1,278	(4,796)
35																				
36	Calculation of Revenue Requirements																			
37	Rate Base	9,959,257	18,918	(129,815)	219,022	10,067,382						(547,556)								
38	Required Operating Income	705,115	1,339	(9,191)	15,507	712,771						(38,767)								
39	Operating Income	606,231	122	(840)	1,416	606,930	13,930	(0)	(7,368)	(2,032)	10,871	(29,829)	1,086	(4,191)	(47)	624	(148)	(3,437)	1,278	(4,796)
40	Income Deficiency	98,884	1,217	(8,351)	14,090	105,840	(13,930)	0	7,368	2,032	(10,871)	(8,938)	(1,086)	4,191	47	(624)	148	3,437	(1,278)	4,796
41	**Revenue Deficiency**	**138,770**	**1,708**	**(11,720)**	**19,774**	**148,531**	**(19,548)**	**0**	**10,340**	**2,851**	**(15,255)**	**(12,543)**	**(1,524)**	**5,882**	**66**	**(875)**	**207**	**4,823**	**(1,793)**	**6,730**
42																				
43	Calculation of Income Taxes																			
44	Operating Revenue	3,963,753				3,963,753	14,021	(15,496)	15,033	(8,285)		(4,590)						(108,280)		(13,649)
45	-Operating Expense	2,501,059				2,501,059	(5,495)	(15,496)	25,373	(5,434)	(15,255)	50,713	(1,524)	5,882	66	(875)	207	(103,457)	(1,793)	(6,918)
46	-Amortization	34,361				34,361														
47	-Taxes Other then Income	281,379			(103,482)	177,897	(32)					(6,335)								
48	Operating Income Before Adjs	1,146,954			103,482	1,250,436	19,548	(0)	(10,340)	(2,851)	15,255	(48,968)	1,524	(5,882)	(66)	875	(207)	(4,823)	1,793	(6,730)
49	Additions to Income	248,212			(103,482)	144,730						(6,339)								
50	Deductions from Income	1,259,160				1,259,160						(41,111)								
51	Debt Synchonization	224,083	426	(2,921)	4,928	226,516						(12,320)								
52	State Taxable Income	(88,077)	(426)	2,921	(4,928)	(90,510)	19,548	(0)	(10,340)	(2,851)	15,255	(1,876)	1,524	(5,882)	(66)	875	(207)	(4,823)	1,793	(6,730)
53	State Income Tax Before Credits	(8,632)	(42)	286	(483)	(8,870)	1,916	(0)	(1,013)	(279)	1,495	(184)	149	(576)	(6)	86	(20)	(473)	176	(660)
54	State Tax Credits	(1,195)				(1,195)														
55	Federal Tax Deductions																			
56	Federal Taxable Income	(78,250)	(384)	2,635	(4,445)	(80,445)	17,632	(0)	(9,327)	(2,572)	13,760	(1,692)	1,375	(5,305)	(59)	790	(187)	(4,350)	1,617	(6,071)
57	Federal Income Tax Before Credits	(16,433)	(81)	553	(933)	(16,893)	3,703	(0)	(1,959)	(540)	2,890	(355)	289	(1,114)	(12)	166	(39)	(914)	340	(1,275)
58	Federal Tax Credits	(112,137)			103,482	(8,655)														
59	Total Income Taxes	(138,396)	(122)	840	102,066	(35,614)	5,618	(0)	(2,972)	(819)	4,385	(539)	438	(1,690)	(19)	252	(60)	(1,386)	515	(1,934)

2020 TEST YEAR INCOME STATEMENT
ADJUSTMENT SCHEDULE

1	2	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39
		WP-A32	WP-A33	WP-A34	WP-A35	WP-A36	WP-A37	WP-A38	WP-A39	WP-A40	WP-A41	WP-A42	WP-A43	WP-A44	WP-A46	WP-A45			
			Amortizations						Rider Removals				Secondary Calculations					Fuel Adjustment	
Line No.	NSPM - 11 Bridge by Report Label - Income Statement	Transmission ROE	Aurora	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Rate Case Expenses	Sherco 3 Depr Deferral	Renewable Connect	Rider: RES	Rider: TCR	Windsource	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss	Total	Remove FCA Revenue and Fuel Expense	Total Net of Fuel
1																			
2	Operating Revenues																		
3	Retail Revenue									(56,514)	(4,994)						3,120,645	(796,055)	2,324,590
4	Interdepartmental																494		494
5	Other Operating	(15,963)				1,750					(90,249)	(10,381)					545,018		545,018
6	Total Revenue	(15,963)				1,750				(56,514)	(95,243)	(10,381)					3,666,158	(796,055)	2,870,103
7																			
8	Expenses																		
9	Operating Expenses																		
10	Fuel & Purchased Energy								(6,395)			(7,605)					937,629	(796,055)	141,574
11	Power Production								1,339	(2,037)	(250)	779					604,726		604,726
12	Transmission	(10,346)									(88,683)						255,621		255,621
13	Distribution																114,249		114,249
14	Customer Accounting																48,973		48,973
15	Customer Service and Information								(25)			(150)					105,520		105,520
16	Sales, Econ Dev, & Other																(6)		(6)
17	Administrative and General																246,966		246,966
18	Total Operating Expenses	(10,346)							(5,081)	(2,037)	(88,933)	(6,976)					2,313,679	(796,055)	1,517,624
19																			
20	Depreciation									(3,879)	(2,095)						683,392		683,392
21	Amortization		1,970	168	2,269	2,884	1,794	503									43,948		43,948
22																			
23	Taxes																		
24	Property									(706)	(39)						178,357		178,357
25	Deferred Income Tax and ITC					(1,179)		(205)		(43,761)	(1,233)					9,770	(71,438)		(71,438)
26	Federal and State Income Tax	(1,614)	(576)	(51)	(301)	351	(516)	(28)	1,460	35,094	339	(979)	88	(69)	4,133	(9,689)	(6,184)		(6,184)
27	Payroll and Other																27,259		27,259
28	Total Taxes	(1,614)	(576)	(51)	(301)	(828)	(516)	(233)	1,460	(9,373)	(933)	(979)	88	(69)	4,133	81	127,994		127,994
29																			
30	Total Expenses	(11,960)	1,394	117	1,968	2,056	1,278	270	(3,621)	(15,289)	(91,961)	(7,955)	88	(69)	4,133	81	3,169,013	(796,055)	2,372,958
31																			
32	Allowance for Funds Used During Constru																28,846		28,846
33																			
34	Net Income	(4,002)	(1,394)	(117)	(1,968)	(305)	(1,278)	(270)	3,621	(41,225)	(3,281)	(2,426)	(88)	69	(4,133)	(81)	525,991		525,991
35																			
36	Calculation of Revenue Requirements																		
37	Rate Base		1,488	419	46,509	23,587		4,319		(549,960)	(43,772)		(13,615)	10,666		(12,565)	8,986,901		8,986,901
38	Required Operating Income		105	30	3,293	1,670		306		(38,937)	(3,099)		(964)	755	33,252	(890)	669,524		669,524
39	Operating Income	(4,002)	(1,394)	(117)	(1,968)	(305)	(1,278)	(270)	3,621	(41,225)	(3,281)	(2,426)	(88)	69	(4,133)	(81)	525,991		525,991
40	Income Deficiency	4,002	1,499	146	5,261	1,975	1,278	576	(3,621)	2,288	182	2,426	(876)	686	37,384	(808)	143,533		143,533
41	**Revenue Deficiency**	**5,616**	**2,104**	**206**	**7,383**	**2,772**	**1,794**	**808**	**(5,081)**	**3,211**	**256**	**3,405**	**(1,229)**	**963**	**52,463**	**(1,134)**	**201,427**		**201,427**
42																			
43	Calculation of Income Taxes																		
44	Operating Revenue	(15,963)				1,750				(56,514)	(95,243)	(10,381)					3,666,158		3,666,158
45	-Operating Expense	(10,346)							(5,081)	(2,037)	(88,933)	(6,976)					2,313,678		2,313,678
46	-Amortization		1,970	168	2,269	2,884	1,794	503									43,948		43,948
47	-Taxes Other then Income					(1,179)		(205)		(44,467)	(1,272)					9,770	134,178		134,178
48	Operating Income Before Adjs	(5,616)	(1,970)	(168)	(2,269)	45	(1,794)	(298)	5,081	(10,011)	(5,038)	(3,405)				(9,770)	1,174,354		1,174,354
49	Additions to Income				2,269	1,705		298		(57,579)	(1,644)					9,770	93,211		93,211
50	Deductions from Income									(172,995)	(6,874)						1,038,181		1,038,181
51	Debt Synchonization		33	9	1,046	531		97		(12,374)	(985)		(306)	240	(14,379)	(283)	187,826		187,826
52	State Taxable Income	(5,616)	(2,003)	(177)	(1,046)	1,220	(1,794)	(97)	5,081	117,780	1,178	(3,405)	306	(240)	14,379	283	41,558		41,558
53	State Income Tax Before Credits	(550)	(196)	(17)	(103)	120	(176)	(10)	498	11,542	115	(334)	30	(24)	1,409	28	4,073		4,073
54	State Tax Credits																(1,195)		(1,195)
55	Federal Tax Deductions																		
56	Federal Taxable Income	(5,066)	(1,807)	(160)	(944)	1,100	(1,618)	(88)	4,583	106,237	1,062	(3,071)	276	(216)	12,970	255	38,680		38,680
57	Federal Income Tax Before Credits	(1,064)	(379)	(34)	(198)	231	(340)	(18)	962	22,310	223	(645)	58	(45)	2,724	54	8,123		8,123
58	Federal Tax Credits									1,241						(9,770)	(17,184)		(17,184)
59	Total Income Taxes	(1,614)	(576)	(51)	(301)	351	(516)	(28)	1,460	35,094	339	(979)	88	(69)	4,133	(9,689)	(6,184)		(6,184)

2021 TEST YEAR INCOME STATEMENT
ADJUSTMENT SCHEDULE

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
							WP-A1 - A15	WP-A16	WP-A17	WP-A18	WP-A19 - A21	WP-A22 - A23	WP-A24	WP-A25	WP-A26	WP-A27	WP-A28	WP-A29	WP-A30	WP-A31
			Unadjusted Secondary Calcs			Base	Precedential	Adjustment												
Line No.	NSPM - 11 Bridge by Report Label - Income Statement	Unadjusted	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Final Unadjusted	Precedential Adjustments	CIP Approved Program Levels	CIP Incentive	IA ROE	Incentive Compensation	Mankato Energy as PPA	Pension: Active Healthcare	Pension: Deferred Amort	Pension: Discount Rate	Pension: Non Qualified	Pension: Retiree Medical	Trading: Asset-Based Margin	Trading: Non Asset-Based Admin	Trading: Non Asset-Based Margin
1																				
2	Operating Revenues																			
3	Retail Revenue	3,183,551				3,183,551		(46,844)												
4	Interdepartmental	494				494														
5	Other Operating	800,891				800,891	12,822		3,654	(9,521)		(4,045)						(108,280)		(13,649)
6	Total Revenue	3,984,937				3,984,937	12,822	(46,844)	3,654	(9,521)		(4,045)						(108,280)		(13,649)
7																				
8	Expenses																			
9	Operating Expenses																			
10	Fuel & Purchased Energy	1,062,360				1,062,360												(103,457)		(6,918)
11	Power Production	599,485				599,485	(16)			(5,641)	(3,867)	51,979								
12	Transmission	360,238				360,238														
13	Distribution	132,140				132,140														
14	Customer Accounting	48,931				48,931														
15	Customer Service and Information	138,556				138,556		(46,844)	13,994											
16	Sales, Econ Dev, & Other						(5)													
17	Administrative and General	268,528				268,528	(5,595)				(12,315)		(1,904)	5,882	66	(817)	206		(1,781)	
18	Total Operating Expenses	2,610,238				2,610,238	(5,616)	(46,844)	13,994	(5,641)	(16,182)	51,979	(1,904)	5,882	66	(817)	206	(103,457)	(1,781)	(6,918)
19																				
20	Depreciation	779,626				779,626						(18,650)								
21	Amortization	33,888				33,888														
22																				
23	Taxes																			
24	Property	187,066				187,066														
25	Deferred Income Tax and ITC	88,399			(187,794)	(99,396)						(5,633)								
26	Federal and State Income Tax	(267,987)	(149)	902	184,387	(82,848)	5,309	(0)	(2,972)	(1,115)	4,651	(1,601)	547	(1,690)	(19)	235	(59)	(1,386)	512	(1,934)
27	Payroll and Other	27,384				27,384	(32)													
28	Total Taxes	34,861	(149)	902	(3,407)	32,206	5,277	(0)	(2,972)	(1,115)	4,651	(7,234)	547	(1,690)	(19)	235	(59)	(1,386)	512	(1,934)
29																				
30	Total Expenses	3,458,613	(149)	902	(3,407)	3,455,958	(340)	(46,844)	11,022	(6,756)	(11,531)	26,095	(1,357)	4,191	47	(582)	147	(104,844)	(1,269)	(8,853)
31																				
32	Allowance for Funds Used During Constru	31,116				31,116						(115)								
33																				
34	Net Income	557,440	149	(902)	3,407	560,095	13,162	(0)	(7,368)	(2,765)	11,531	(30,255)	1,357	(4,191)	(47)	582	(147)	(3,437)	1,269	(4,796)
35																				
36	Calculation of Revenue Requirements																			
37	Rate Base	10,411,119	23,090	(139,445)	517,285	10,812,048						(526,198)								
38	Required Operating Income	737,107	1,635	(9,873)	36,624	765,493						(37,255)								
39	Operating Income	557,440	149	(902)	3,407	560,095	13,162	(0)	(7,368)	(2,765)	11,531	(30,255)	1,357	(4,191)	(47)	582	(147)	(3,437)	1,269	(4,796)
40	Income Deficiency	179,667	1,485	(8,971)	33,217	205,398	(13,162)	0	7,368	2,765	(11,531)	(6,999)	(1,357)	4,191	47	(582)	147	3,437	(1,269)	4,796
41	**Revenue Deficiency**	**252,137**	**2,085**	**(12,589)**	**46,614**	**288,246**	**(18,471)**	**0**	**10,340**	**3,880**	**(16,182)**	**(9,823)**	**(1,904)**	**5,882**	**66**	**(817)**	**206**	**4,823**	**(1,781)**	**6,730**
42																				
43	Calculation of Income Taxes																			
44	Operating Revenue	3,984,937				3,984,937	12,822	(46,844)	3,654	(9,521)		(4,045)						(108,280)		(13,649)
45	-Operating Expense	2,610,238				2,610,238	(5,616)	(46,844)	13,994	(5,641)	(16,182)	51,979	(1,904)	5,882	66	(817)	206	(103,457)	(1,781)	(6,918)
46	-Amortization	33,888				33,888														
47	-Taxes Other then Income	302,848			(187,794)	115,054	(32)					(5,633)								
48	Operating Income Before Adjs	1,037,962			187,794	1,225,757	18,471	(0)	(10,340)	(3,880)	16,182	(50,391)	1,904	(5,882)	(66)	817	(206)	(4,823)	1,781	(6,730)
49	Additions to Income	253,030			(187,794)	65,236						(5,706)								
50	Deductions from Income	1,367,087			(31,119)	1,335,968						(38,687)								
51	Debt Synchronization	234,250	520	(3,138)	11,639	243,271						(11,839)								
52	State Taxable Income	(310,344)	(520)	3,138	19,480	(288,246)	18,471	(0)	(10,340)	(3,880)	16,182	(5,571)	1,904	(5,882)	(66)	817	(206)	(4,823)	1,781	(6,730)
53	State Income Tax Before Credits	(30,414)	(51)	307	1,909	(28,248)	1,810	(0)	(1,013)	(380)	1,586	(546)	187	(576)	(6)	80	(20)	(473)	175	(660)
54	State Tax Credits	(1,195)			1,195															
55	Federal Tax Deductions																			
56	Federal Taxable Income	(278,735)	(469)	2,830	16,376	(259,998)	16,661	(0)	(9,327)	(3,499)	14,596	(5,025)	1,718	(5,305)	(59)	737	(186)	(4,350)	1,607	(6,071)
57	Federal Income Tax Before Credits	(58,534)	(98)	594	3,439	(54,600)	3,499	(0)	(1,959)	(735)	3,065	(1,055)	361	(1,114)	(12)	155	(39)	(914)	337	(1,275)
58	Federal Tax Credits	(177,844)			177,844															
59	Total Income Taxes	(267,987)	(149)	902	184,387	(82,848)	5,309	(0)	(2,972)	(1,115)	4,651	(1,601)	547	(1,690)	(19)	235	(59)	(1,386)	512	(1,934)

Northern States Power Company

Docket No. E002/GR-19-564
Exhibit___(BCH-1), Schedule 11b

2021 TEST YEAR INCOME STATEMENT ADJUSTMENT SCHEDULE

1	2	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39
		WP-A32	WP-A33	WP-A34	WP-A35	WP-A36	WP-A37	WP-A38	WP-A39	WP-A40	WP-A41	WP-A42	WP-A43	WP-A44	WP-A46	WP-A45			
			Amortizations						Rider Removals				Secondary Calculations					Fuel Adjustment	
Line No.	NSPM - 11 Bridge by Report Label - Income Statement	Transmission ROE	Aurora	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Rate Case Expenses	Sherco 3 Depr Deferral	Renewable Connect	Rider: RES	Rider: TCR	Windsource	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss	Total	Remove FCA Revenue and Fuel Expense	Total Net of Fuel
1																			
2	Operating Revenues																		
3	Retail Revenue									(52,116)	(4,142)						3,080,450	(796,055)	2,284,395
4	Interdepartmental																494		494
5	Other Operating	(16,336)				1,622					(96,541)	(10,381)					560,238		560,238
6	Total Revenue	(16,336)				1,622				(52,116)	(100,683)	(10,381)					3,641,181	(796,055)	2,845,126
7																			
8	Expenses																		
9	Operating Expenses																		
10	Fuel & Purchased Energy								(6,395)			(7,605)					937,984	(796,055)	141,929
11	Power Production								1,364	(15,102)	(429)	779					628,551		628,551
12	Transmission	(9,611)									(90,355)						260,272		260,272
13	Distribution																132,140		132,140
14	Customer Accounting																48,931		48,931
15	Customer Service and Information								(25)			(150)					105,532		105,532
16	Sales, Econ Dev, & Other																(5)		(5)
17	Administrative and General																252,269		252,269
18	Total Operating Expenses	(9,611)							(5,056)	(15,102)	(90,784)	(6,976)					2,365,673	(796,055)	1,569,618
19																			
20	Depreciation									(38,437)	(3,015)						719,524		719,524
21	Amortization		1,970	168	2,269	2,884	1,794	503									43,475		43,475
22																			
23	Taxes																		
24	Property									(2,977)	(564)						183,524		183,524
25	Deferred Income Tax and ITC					(1,179)		(205)		(79,576)	(2,438)					15,756	(172,672)		(172,672)
26	Federal and State Income Tax	(1,933)	(569)	(50)	(286)	325	(516)	(26)	1,453	154,591	1,099	(979)	152	(80)	4,281	(15,515)	59,576		59,576
27	Payroll and Other																27,352		27,352
28	Total Taxes	(1,933)	(569)	(50)	(286)	(854)	(516)	(231)	1,453	72,038	(1,904)	(979)	152	(80)	4,281	241	97,780		97,780
29																			
30	Total Expenses	(11,544)	1,400	118	1,983	2,030	1,278	272	(3,603)	18,499	(95,703)	(7,955)	152	(80)	4,281	241	3,226,452	(796,055)	2,430,397
31																			
32	Allowance for Funds Used During Constru																31,000		31,000
33																			
34	Net Income	(4,792)	(1,400)	(118)	(1,983)	(408)	(1,278)	(272)	3,603	(70,615)	(4,979)	(2,426)	(152)	80	(4,281)	(240)	445,730	-	445,730
35																			
36	Calculation of Revenue Requirements																		
37	Rate Base		492	252	44,240	21,882		4,021		(942,039)	(66,423)		(23,467)	12,415		(27,678)	9,309,544		9,309,544
38	Required Operating Income		35	18	3,132	1,549		285		(66,696)	(4,703)		(1,661)	879	34,445	(1,960)	693,561		693,561
39	Operating Income	(4,792)	(1,400)	(118)	(1,983)	(408)	(1,278)	(272)	3,603	(70,615)	(4,979)	(2,426)	(152)	80	(4,281)	(240)	445,730		445,730
40	Income Deficiency	4,792	1,435	136	5,115	1,957	1,278	557	(3,603)	3,919	276	2,426	(1,510)	799	38,727	(1,720)	247,831		247,831
41	**Revenue Deficiency**	**6,724**	**2,014**	**190**	**7,178**	**2,746**	**1,794**	**781**	**(5,056)**	**5,499**	**388**	**3,405**	**(2,119)**	**1,121**	**54,347**	**(2,413)**	**347,794**		**347,794**
42																			
43	Calculation of Income Taxes																		
44	Operating Revenue	(16,336)				1,622				(52,116)	(100,683)	(10,381)					3,641,181	(796,055)	2,845,126
45	-Operating Expense	(9,611)							(5,056)	(15,102)	(90,784)	(6,976)					2,365,673	(796,055)	1,569,618
46	-Amortization		1,970	168	2,269	2,884	1,794	503									43,475		43,475
47	-Taxes Other then Income					(1,179)		(205)		(82,553)	(3,003)					15,756	38,204		38,204
48	Operating Income Before Adjs	(6,724)	(1,970)	(168)	(2,269)	(83)	(1,794)	(298)	5,056	45,539	(6,896)	(3,405)				(15,756)	1,193,829		1,193,829
49	Additions to Income				2,269	1,705		298		(85,778)	(3,780)					15,756	(10,001)		(10,001)
50	Deductions from Income									(327,244)	(13,003)					31,119	988,153		988,153
51	Debt Synchronization		11	6	995	492		90		(21,196)	(1,495)		(528)	279	(14,895)	(623)	194,569		194,569
52	State Taxable Income	(6,724)	(1,981)	(173)	(995)	1,130	(1,794)	(90)	5,056	308,200	3,822	(3,405)	528	(279)	14,895	(30,496)	1,105		1,105
53	State Income Tax Before Credits	(659)	(194)	(17)	(98)	111	(176)	(9)	495	30,204	375	(334)	52	(27)	1,460	(2,989)	108		108
54	State Tax Credits															(1,195)	(1,195)		(1,195)
55	Federal Tax Deductions																		
56	Federal Taxable Income	(6,065)	(1,787)	(156)	(898)	1,019	(1,618)	(82)	4,561	277,997	3,448	(3,071)	476	(252)	13,436	(26,312)	2,192		2,192
57	Federal Income Tax Before Credits	(1,274)	(375)	(33)	(189)	214	(340)	(17)	958	58,379	724	(645)	100	(53)	2,821	(5,526)	460		460
58	Federal Tax Credits									66,008						(5,805)	60,203		60,203
59	Total Income Taxes	(1,933)	(569)	(50)	(286)	325	(516)	(26)	1,453	154,591	1,099	(979)	152	(80)	4,281	(15,515)	59,576		59,576

2022 TEST YEAR INCOME STATEMENT
ADJUSTMENT SCHEDULE

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
							WP-A1 - A15	WP-A16	WP-A17	WP-A18	WP-A19 - A21	WP-A22 - A23	WP-A24	WP-A25	WP-A26	WP-A27	WP-A28	WP-A29	WP-A30	WP-A31
			Unadjusted Secondary Calcs			Base	Precedential	Adjustment												
Line No.	NSPM - 11 Bridge by Report Label - Income Statement	Unadjusted	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Final Unadjusted	Precedential Adjustments	CIP Approved Program Levels	CIP Incentive	IA ROE	Incentive Compensation	Mankato Energy as PPA	Pension: Active Healthcare	Pension: Deferred Amort	Pension: Discount Rate	Pension: Non Qualified	Pension: Retiree Medical	Trading: Asset-Based Margin	Trading: Non Asset-Based Admin	Trading: Non Asset-Based Margin
1																				
2	Operating Revenues																			
3	Retail Revenue	3,165,850				3,165,850		(49,589)												
4	Interdepartmental	494				494														
5	Other Operating	825,186				825,186	12,213			(9,963)		(3,648)						(108,280)		(13,649)
6	Total Revenue	3,991,531				3,991,531	12,213	(49,589)		(9,963)		(3,648)						(108,280)		(13,649)
7																				
8	Expenses																			
9	Operating Expenses																			
10	Fuel & Purchased Energy	1,061,665				1,061,665												(103,457)		(6,918)
11	Power Production	610,736				610,736				(5,923)	(4,086)	52,945								
12	Transmission	370,336				370,336														
13	Distribution	127,086				127,086														
14	Customer Accounting	43,907				43,907														
15	Customer Service and Information	144,996				144,996		(49,589)	10,340											
16	Sales, Econ Dev, & Other						(5)													
17	Administrative and General	277,657				277,657	(5,645)				(12,959)		(2,335)	5,882	66	(748)	206		(1,820)	
18	Total Operating Expenses	2,636,383				2,636,383	(5,650)	(49,589)	10,340	(5,923)	(17,046)	52,945	(2,335)	5,882	66	(748)	206	(103,457)	(1,820)	(6,918)
19																				
20	Depreciation	832,484				832,484						(18,840)								
21	Amortization	37,139				37,139														
22																				
23	Taxes																			
24	Property	202,475				202,475														
25	Deferred Income Tax and ITC	30,677			(162,293)	(131,615)						(4,748)								
26	Federal and State Income Tax	(252,058)	(56)	999	157,892	(93,208)	5,143		(2,972)	(1,161)	4,899	(2,736)	671	(1,690)	(19)	215	(59)	(1,386)	523	(1,934)
27	Payroll and Other	27,468				27,468	(32)													
28	Total Taxes	8,562	(56)	999	(4,400)	5,119	5,111		(2,972)	(1,161)	4,899	(7,484)	671	(1,690)	(19)	215	(59)	(1,386)	523	(1,934)
29																				
30	Total Expenses	3,514,567	(56)	999	(4,400)	3,511,125	(539)	(49,589)	7,368	(7,084)	(12,146)	26,621	(1,664)	4,191	47	(533)	147	(104,844)	(1,297)	(8,853)
31																				
32	Allowance for Funds Used During Constru	33,511				33,511						(11)								
33																				
34	Net Income	510,475	56	(999)	4,400	513,917	12,752		(7,368)	(2,879)	12,146	(30,280)	1,664	(4,191)	(47)	533	(147)	(3,437)	1,297	(4,796)
35																				
36	Calculation of Revenue Requirements																			
37	Rate Base	10,735,676	8,736	(154,456)	687,629	11,277,585						(505,827)								
38	Required Operating Income	760,086	619	(10,935)	48,684	798,453						(35,813)								
39	Operating Income	510,475	56	(999)	4,400	513,917	12,752		(7,368)	(2,879)	12,146	(30,280)	1,664	(4,191)	(47)	533	(147)	(3,437)	1,297	(4,796)
40	Income Deficiency	249,611	562	(9,937)	44,284	284,536	(12,752)		7,368	2,879	(12,146)	(5,533)	(1,664)	4,191	47	(533)	147	3,437	(1,297)	4,796
41	**Revenue Deficiency**	**350,292**	**789**	**(13,945)**	**62,146**	**399,304**	**(17,895)**		**10,340**	**4,040**	**(17,046)**	**(7,764)**	**(2,335)**	**5,882**	**66**	**(748)**	**206**	**4,823**	**(1,820)**	**6,730**
42																				
43	Calculation of Income Taxes																			
44	Operating Revenue	3,991,531				3,991,531	12,213	(49,589)		(9,963)		(3,648)						(108,280)		(13,649)
45	-Operating Expense	2,636,383				2,636,383	(5,650)	(49,589)	10,340	(5,923)	(17,046)	52,945	(2,335)	5,882	66	(748)	206	(103,457)	(1,820)	(6,918)
46	-Amortization	37,139				37,139														
47	-Taxes Other then Income	260,620			(162,293)	98,328	(32)					(4,748)								
48	Operating Income Before Adjs	1,057,389			162,293	1,219,682	17,895		(10,340)	(4,040)	17,046	(51,845)	2,335	(5,882)	(66)	748	(206)	(4,823)	1,820	(6,730)
49	Additions to Income	194,426			(162,293)	32,133						(4,755)								
50	Deductions from Income	1,197,875			31,119	1,228,994						(35,701)								
51	Debt Synchronization	241,553	197	(3,475)	15,525	253,746						(11,381)								
52	State Taxable Income	(187,613)	(197)	3,475	(46,644)	(230,925)	17,895		(10,340)	(4,040)	17,046	(9,518)	2,335	(5,882)	(66)	748	(206)	(4,823)	1,820	(6,730)
53	State Income Tax Before Credits	(18,386)	(19)	341	(4,571)	(22,631)	1,754		(1,013)	(396)	1,670	(933)	229	(576)	(6)	73	(20)	(473)	178	(660)
54	State Tax Credits	(1,195)			(1,195)	(2,391)														
55	Federal Tax Deductions																			
56	Federal Taxable Income	(168,032)	(177)	3,135	(40,877)	(205,904)	16,142		(9,327)	(3,644)	15,375	(8,585)	2,107	(5,305)	(59)	675	(186)	(4,350)	1,642	(6,071)
57	Federal Income Tax Before Credits	(35,287)	(37)	658	(8,584)	(43,240)	3,390		(1,959)	(765)	3,229	(1,803)	442	(1,114)	(12)	142	(39)	(914)	345	(1,275)
58	Federal Tax Credits	(197,190)			172,243	(24,947)														
59	Total Income Taxes	(252,058)	(56)	999	157,892	(93,208)	5,143		(2,972)	(1,161)	4,899	(2,736)	671	(1,690)	(19)	215	(59)	(1,386)	523	(1,934)

2022 TEST YEAR INCOME STATEMENT
ADJUSTMENT SCHEDULE

1	2	22 WP-A32	23 WP-A33	24 WP-A34	25 WP-A35	26 WP-A36	27 WP-A37	28 WP-A38	29 WP-A39	30 WP-A40	31 WP-A41	32 WP-A42	33 WP-A43	34 WP-A44	35 WP-A46	36 WP-A45	37
			Amortizations						Rider Removals				Secondary Calculations				
Line No.	NSPM - 11 Bridge by Report Label - Income Statement	Transmission ROE	Aurora	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Rate Case Expenses	Sherco 3 Depr Deferral	Renewable Connect	Rider: RES	Rider: TCR	Windsource	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss	Total
1																	
2	Operating Revenues																
3	Retail Revenue									(44,519)	(2,799)						3,068,944
4	Interdepartmental																494
5	Other Operating	(16,870)				1,494					(101,366)	(10,381)					574,739
6	Total Revenue	(16,870)				1,494				(44,519)	(104,165)	(10,381)					3,644,177
7																	
8	Expenses																
9	Operating Expenses																
10	Fuel & Purchased Energy								(6,395)			(7,605)					937,289
11	Power Production								3,863	(20,119)	(430)	779					637,764
12	Transmission	(9,580)									(91,069)						269,688
13	Distribution																127,086
14	Customer Accounting																43,907
15	Customer Service and Information								(25)			(150)					105,572
16	Sales, Econ Dev, & Other																(5)
17	Administrative and General																260,301
18	Total Operating Expenses	(9,580)							(2,558)	(20,119)	(91,499)	(6,976)					2,381,602
19																	
20	Depreciation									(48,577)	(4,208)						760,859
21	Amortization			168	2,269	2,884	1,794	503									44,757
22																	
23	Taxes																
24	Property									(4,072)	(1,312)						197,091
25	Deferred Income Tax and ITC					(1,179)		(205)		(55,791)	(2,108)					4,750	(190,897)
26	Federal and State Income Tax	(2,095)		(49)	(271)	299	(516)	(24)	735	153,141	576	(979)	113	(88)	3,946	(4,596)	56,478
27	Payroll and Other																27,435
28	Total Taxes	(2,095)		(49)	(271)	(880)	(516)	(229)	735	93,277	(2,843)	(979)	113	(88)	3,946	154	90,108
29																	
30	Total Expenses	(11,675)		119	1,997	2,004	1,278	274	(1,822)	24,581	(98,550)	(7,955)	113	(88)	3,946	154	3,277,326
31																	
32	Allowance for Funds Used During Constru																33,500
33																	
34	Net Income	(5,195)		(119)	(1,997)	(510)	(1,278)	(274)	1,822	(69,100)	(5,616)	(2,426)	(113)	88	(3,946)	(154)	400,352
35																	
36	Calculation of Revenue Requirements																
37	Rate Base			84	41,972	20,177		3,723		(920,073)	(74,773)		(17,463)	13,568		(33,232)	9,805,740
38	Required Operating Income			6	2,972	1,429		264		(65,141)	(5,294)		(1,236)	961	38,242	(2,353)	732,489
39	Operating Income	(5,195)		(119)	(1,997)	(510)	(1,278)	(274)	1,822	(69,100)	(5,616)	(2,426)	(113)	88	(3,946)	(154)	400,352
40	Income Deficiency	5,195		125	4,969	1,939	1,278	537	(1,822)	3,959	322	2,426	(1,123)	873	42,188	(2,199)	332,137
41	**Revenue Deficiency**	**7,290**		**175**	**6,973**	**2,721**	**1,794**	**754**	**(2,558)**	**5,555**	**451**	**3,405**	**(1,577)**	**1,225**	**59,205**	**(3,086)**	**466,104**
42																	
43	Calculation of Income Taxes																
44	Operating Revenue	(16,870)				1,494				(44,519)	(104,165)	(10,381)					3,644,177
45	-Operating Expense	(9,580)							(2,558)	(20,119)	(91,499)	(6,976)					2,381,602
46	-Amortization			168	2,269	2,884	1,794	503									44,757
47	-Taxes Other then Income					(1,179)		(205)		(59,863)	(3,420)					4,750	33,630
48	Operating Income Before Adjs	(7,290)		(168)	(2,269)	(211)	(1,794)	(298)	2,558	35,464	(9,247)	(3,405)				(4,750)	1,184,189
49	Additions to Income				2,269	1,705		298		(55,827)	(2,109)					4,750	(21,536)
50	Deductions from Income									(246,593)	(11,679)					(31,119)	903,902
51	Debt Synchronization			2	944	454		84		(20,702)	(1,682)		(393)	305	(13,728)	(748)	206,901
52	State Taxable Income	(7,290)		(170)	(944)	1,040	(1,794)	(84)	2,558	246,932	2,006	(3,405)	393	(305)	13,728	31,867	51,850
53	State Income Tax Before Credits	(714)		(17)	(93)	102	(176)	(8)	251	24,199	197	(334)	39	(30)	1,345	3,123	5,081
54	State Tax Credits															1,195	(1,195)
55	Federal Tax Deductions																
56	Federal Taxable Income	(6,575)		(153)	(852)	938	(1,618)	(76)	2,307	222,732	1,809	(3,071)	354	(275)	12,383	27,549	47,964
57	Federal Income Tax Before Credits	(1,381)		(32)	(179)	197	(340)	(16)	484	46,774	380	(645)	74	(58)	2,600	5,785	10,072
58	Federal Tax Credits									82,168						(14,701)	42,520
59	Total Income Taxes	(2,095)		(49)	(271)	299	(516)	(24)	735	153,141	576	(979)	113	(88)	3,946	(4,597)	56,478

2020-2022 MYRP ADJUSTMENT SUMMARY

(1) Line No.	(2) Record Category	(3) Report Label	(4) Record Type	(5) MN Electric 2020 Test Year	(6) MN Electric 2021 Plan Year	(7) MN Electric 2022 Plan Year	(8) Workpaper Reference
1	Unadjusted	Unadjusted	**Total Unadjusted**	**196,909,388**	**312,912,994**	**415,108,228**	
2							
3	Precedential	Precedential Adjustments	NSPM-Advertising (Trad)	(2,846,381)	(2,912,580)	(2,967,208)	WP-A1
4	Precedential	Precedential Adjustments	NSPM-Assn Dues (Trad)	(734,495)	(724,005)	(723,460)	WP-A2
5	Precedential	Precedential Adjustments	NSPM-Aviation (remove 100%)	(2,051,482)	(2,094,034)	(2,139,338)	WP-A3
6	Precedential	Precedential Adjustments	NSPM-Chamber of Commerce Dues	214,391	215,975	217,580	WP-A4
7	Precedential	Precedential Adjustments	NSPM-Customer Deposits - A&G Expense (Trad)	18,870	18,870	18,870	WP-A5
8	Precedential	Precedential Adjustments	NSPM-Donations (Trad)	1,851,065	1,851,564	1,852,349	WP-A6
9	Precedential	Precedential Adjustments	NSPM-Econ Dev Donations (Trad)	50,660	51,144	51,632	WP-A7
10	Precedential	Precedential Adjustments	NSPM-Econ Develop (Trad)	(56,203)	(56,203)	(56,203)	WP-A8
11	Precedential	Precedential Adjustments	NSPM-Employee Expenses	(1,485,915)	(1,505,456)	(1,454,796)	WP-A9
12	Precedential	Precedential Adjustments	NSPM-Foundation Admin	(113,729)	(115,300)	(116,960)	WP-A10
13	Precedential	Precedential Adjustments	NSPM-Investor Relations	(358,045)	(362,548)	(364,736)	WP-A11
14	Precedential	Precedential Adjustments	NSPM-Monticello EPU Commission Order No Return	(11,636,431)	(10,390,232)	(9,242,691)	WP-A12
15	Precedential	Precedential Adjustments	NSPM-Nobles Disallowed Assets	(191,073)	(177,039)	(163,345)	WP-A13
16	Precedential	Precedential Adjustments	NSPM-Nuclear Retention Removal	(15,818)	(15,818)		WP-A14
17	Precedential	Precedential Adjustments	NSPM-Other Revenue to 3 Year Average Adj	(2,193,405)	(2,255,012)	(2,807,078)	WP-A15
18	Precedential		**Sub-Total Precedential**	**(19,547,993)**	**(18,470,674)**	**(17,895,384)**	
19							
20	Adjustment	CIP Approved Program Levels	NSPM-CIP Revenue and Expense Elimination		1		WP-A16
21	Adjustment	CIP Incentive	NSPM-CIP Incentive - Retain Shareholder Portion	10,340,229	10,340,229	10,340,229	WP-A17
22	Adjustment	IA ROE	NSPM-IA ROE	2,851,091	3,879,582	4,039,956	WP-A18
23	Adjustment	Incentive Compensation	NSPM-Incentive Pay	(1,901,127)	(1,958,159)	(2,016,905)	WP-A19
24	Adjustment	Incentive Compensation	NSPM-Incentive Pay_Environmental LTI	1,939,801	2,009,497	2,119,491	WP-A20
25	Adjustment	Incentive Compensation	NSPM-Incentive Pay_Remove Long Term	(15,293,947)	(16,233,456)	(17,148,300)	WP-A21
26	Adjustment	Mankato Energy	NSPM-Mankato Energy Center	(64,186,320)	(62,039,064)	(60,692,423)	WP-A22
27	Adjustment	Mankato Energy	NSPM-MEC PPA Cost	48,446,937	49,144,661	49,874,150	WP-A23
28	Adjustment	Pension: Active Healthcare	NSPM-Pension Active Healthcare	(1,524,307)	(1,904,372)	(2,335,431)	WP-A24
29	Adjustment	Pension: Deferred Amort	NSPM-Pension Deferred Amortization	5,881,632	5,881,632	5,881,632	WP-A25
30	Adjustment	Pension: Discount Rate	NSPM-Pension Discount Rate Int	65,960	65,821	65,885	WP-A26
31	Adjustment	Pension: Non Qualified	NSPM-Non Qualified Pension Removal	(875,437)	(817,203)	(748,194)	WP-A27
32	Adjustment	Pension: Retiree Medical	NSPM-Pension Retiree Medical	207,079	206,323	205,764	WP-A28
33	Adjustment	Trading: Asset-Based Margin	NSPM-Remove Asset Trading	4,822,836	4,822,836	4,822,836	WP-A29
34	Adjustment	Trading: Non Asset-Based Admin	NSPM-Remove NonAsset Trading Fully Allocated Costs	(1,793,054)	(1,781,312)	(1,820,356)	WP-A30
35	Adjustment	Trading: Non Asset-Based Margin	NSPM-Remove NonAsset Trading	6,730,471	6,730,471	6,730,471	WP-A31
36	Adjustment	Transmission ROE	NSPM-Transmission ROE Change	5,616,345	6,724,271	7,289,797	WP-A32
37	Adjustment		**Sub-Total Adjustment**	**1,328,189**	**5,071,757**	**6,608,603**	
38							
39	Amortization	Aurora	NSPM-Aurora Deferral	2,112,688	2,016,945		WP-A33
40	Amortization	LED Street Lighting	NSPM-Settlement LED Street Lighting	207,983	191,865	175,764	WP-A34
41	Amortization	NOL ADIT ARAM	NSPM-NOL Tax Reform ADIT ARAM	7,654,276	7,436,206	7,226,530	WP-A35
42	Amortization	PI EPU Recovery	NSPM-PI EPU Deferral	2,909,573	2,873,937	2,842,337	WP-A36
43	Amortization	Rate Case Expenses	NSPM-Amortization Rate Case Expense	1,794,123	1,794,123	1,794,123	WP-A37
44	Amortization	Sherco 3 Depr Deferral	NSPM-Sherco 3 Deferral	833,079	804,451	776,567	WP-A38
45	Amortization		**Sub-Total Amortization**	**15,511,723**	**15,117,527**	**12,815,321**	
46							
47	Rider Removals	Renewable Connect	NSPM-Remove Renewable Connect	(5,080,949)	(5,055,990)	(2,557,503)	WP-A39
48	Rider Removals	Rider: RES	NSPM-RES Rider Removal	0	0	0	WP-A40
49	Rider Removals	Rider: TCR	NSPM-TCR Rider Removal	0	(0)	(0)	WP-A41
50	Rider Removals	Windsource	NSPM-Remove Windsource	3,404,613	3,404,613	3,404,613	WP-A42
51	Rider Removals		**Sub-Total Rider Removals**	**(1,676,336)**	**(1,651,377)**	**847,110**	
52							
53	Secondary Calculations	ADIT Prorate for IRS	NSPM-ADIT Prorate for IRS	509,783	(36,227)	(840,601)	WP-A43
54	Secondary Calculations	Cash Working Capital	NSPM-Cash Working Capital	(11,452,564)	(12,210,115)	(13,570,274)	WP-A44
55	Secondary Calculations	Net Operating Loss	NSPM-NOL/Credits/199	19,844,507	47,060,791	63,031,282	WP-A45
56	Secondary Calculations		**Sub-Total Secondary Calculations**	**8,901,727**	**34,814,450**	**48,620,407**	
57							
58			Total Revenue Deficiency	201,426,697	347,794,678	466,104,285	

Northern States Power Company

Docket No. E002/GR-19-564
Exhibit___(BCH-1), Schedule 13

PRECEDENTIAL ADJUSTMENT DETAIL SCHEDULE
2020 Unadjusted Test Year versus 2020 Adjusted Test Year
($000s)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	
		Precedential Adjustments																
Line No.	NSPM - 11 Bridge by Report Lable - Precedential Adjustments	NSPM-Advertising	NSPM-Assn Dues	NSPM-Aviation	NSPM-Chamber of Commerce Dues	NSPM-Customer Deposits - A&G Expense	NSPM-Donations	NSPM-Econ Dev Donations	NSPM-Econ Develop	NSPM-Employee Expenses	NSPM-Foundation Admin	NSPM-Investor Relations	NSPM-Monticello EPU Commission Order No Return	NSPM-Nobles Disallowed Assets	NSPM-Nuclear Retention Removal	NSPM-Other Revenue to 3 Year Average Adj	Total	
1																		
2	Operating Revenues																	
3	Retail Revenue																	
4	Other Operating												11,636	191		2,193	14,021	
5	Total Revenue												11,636	191		2,193	14,021	
6																		
7	Expenses																	
8	Operating Expenses																	
9	Power Production														(16)		(16)	
10	Customer Accounting																	
11	Customer Service and Information																	
12	Sales, Econ Dev, & Other							51	(56)								(6)	
13	Administrative and General	(2,846)	(734)	(2,029)	214	19	1,851			(1,486)	(110)	(352)					(5,474)	
14	Total Operating Expenses	(2,846)	(734)	(2,029)	214	19	1,851	51	(56)	(1,486)	(110)	(352)			(16)		(5,495)	
15																		
16	Depreciation																	
17	Amortization																	
18																		
19	Taxes																	
20	Property																	
21	Deferred Income Tax and ITC																	
22	Federal and State Income Tax	818	211	590	(62)	(5)	(532)	(15)	16	427	33	103	3,345	55	5	630	5,618	
23	Payroll and Other			(22)							(4)	(6)					(32)	
24	Total Taxes	818	211	567	(62)	(5)	(532)	(15)	16	427	29	97	3,345	55	5	630	5,587	
25																		
26	Total Expenses	(2,028)	(523)	(1,462)	153	13	1,319	36	(40)	(1,059)	(81)	(255)	3,345	55	(11)	630	91	
27																		
28	Allowance for Funds Used During Constru																	
29																		
30	Net Income	2,028	523	1,462	(153)	(13)	(1,319)	(36)	40	1,059	81	255	8,292	136	11	1,563	13,930	
31																		
32	Calculation of Revenue Requirements																	
33	Rate Base																	
34	Required Operating Income																	
35	Operating Income	2,028	523	1,462	(153)	(13)	(1,319)	(36)	40	1,059	81	255	8,292	136	11	1,563	13,930	
36	Income Deficiency	(2,028)	(523)	(1,462)	153	13	1,319	36	(40)	(1,059)	(81)	(255)	(8,292)	(136)	(11)	(1,563)	(13,930)	
37	**Revenue Deficiency**	**(2,846)**	**(734)**	**(2,051)**	**214**	**19**	**1,851**	**51**	**(56)**	**(1,486)**	**(114)**	**(358)**	**(11,636)**	**(191)**	**(16)**	**(2,193)**	**(19,548)**	Ties to schedule 12 and schedule 11a
38																		
39	Calculation of Income Taxes																	
40	Operating Revenue												11,636	191		2,193	14,021	
41	-Operating Expense	(2,846)	(734)	(2,029)	214	19	1,851	51	(56)	(1,486)	(110)	(352)			(16)		(5,495)	
42	-Amortization																	
43	-Taxes Other then Income			(22)							(4)	(6)					(32)	
44	Operating Income Before Adjs	2,846	734	2,051	(214)	(19)	(1,851)	(51)	56	1,486	114	358	11,636	191	16	2,193	19,548	
45	Additions to Income																	
46	Deductions from Income																	
47	Debt Synchronization																	
48	State Taxable Income	2,846	734	2,051	(214)	(19)	(1,851)	(51)	56	1,486	114	358	11,636	191	16	2,193	19,548	
49	State Income Tax Before Credits	279	72	201	(21)	(2)	(181)	(5)	6	146	11	35	1,140	19	2	215	1,916	
50	State Tax Credits																	
51	Federal Tax Deductions																	
52	Federal Taxable Income	2,567	663	1,850	(193)	(17)	(1,670)	(46)	51	1,340	103	323	10,496	172	14	1,978	17,632	
53	Federal Income Tax Before Credits	539	139	389	(41)	(4)	(351)	(10)	11	281	22	68	2,204	36	3	415	3,703	
54	Federal Tax Credits																	
55	Total Income Taxes	818	211	590	(62)	(5)	(532)	(15)	16	427	33	103	3,345	55	5	630	5,618	

* Revenue requirements calculated at the last authorized rate of return

Northern States Power Company

PRECEDENTIAL ADJUSTMENT DETAIL SCHEDULE
2021 Unadjusted Test Year versus 2021 Adjusted Test Year
($000s)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
		Precedential Adjustments															
Line No.	NSPM - 11 Bridge by Report Lable - Precedential Adjustments	NSPM-Advertising	NSPM-Assn Dues	NSPM-Aviation	NSPM-Chamber of Commerce Dues	NSPM-Customer Deposits - A&G Expense	NSPM-Donations	NSPM-Econ Dev Donations	NSPM-Econ Develop	NSPM-Employee Expenses	NSPM-Foundation Admin	NSPM-Investor Relations	NSPM-Monticello EPU Commission Order No Return	NSPM-Nobles Disallowed Assets	NSPM-Nuclear Retention Removal	NSPM-Other Revenue to 3 Year Average Adj	Total
1																	
2	Operating Revenues																
3	Retail Revenue																
4	Other Operating												10,390	177		2,255	12,822
5	Total Revenue												10,390	177		2,255	12,822
6																	
7	Expenses																
8	Operating Expenses																
9	Power Production														(16)		(16)
10	Customer Accounting																
11	Customer Service and Information																
12	Sales, Econ Dev, & Other							51	(56)								(5)
13	Administrative and General	(2,913)	(724)	(2,072)	216	19	1,852			(1,505)	(111)	(357)					(5,595)
14	Total Operating Expenses	(2,913)	(724)	(2,072)	216	19	1,852	51	(56)	(1,505)	(111)	(357)			(16)		(5,616)
15																	
16	Depreciation																
17	Amortization																
18																	
19	Taxes																
20	Property																
21	Deferred Income Tax and ITC																
22	Federal and State Income Tax	837	208	602	(62)	(5)	(532)	(15)	16	433	33	104	2,986	51	5	648	5,309
23	Payroll and Other			(22)							(4)	(6)					(32)
24	Total Taxes	837	208	579	(62)	(5)	(532)	(15)	16	433	29	99	2,986	51	5	648	5,277
25																	
26	Total Expenses	(2,075)	(516)	(1,492)	154	13	1,319	36	(40)	(1,073)	(82)	(258)	2,986	51	(11)	648	(340)
27																	
28	Allowance for Funds Used During Construction																
29																	
30	Net Income	2,075	516	1,492	(154)	(13)	(1,319)	(36)	40	1,073	82	258	7,404	126	11	1,607	13,162
31																	
32	Calculation of Revenue Requirements																
33	Rate Base																
34	Required Operating Income																
35	Operating Income	2,075	516	1,492	(154)	(13)	(1,319)	(36)	40	1,073	82	258	7,404	126	11	1,607	13,162
36	Income Deficiency	(2,075)	(516)	(1,492)	154	13	1,319	36	(40)	(1,073)	(82)	(258)	(7,404)	(126)	(11)	(1,607)	(13,162)
37	**Revenue Deficiency**	**(2,913)**	**(724)**	**(2,094)**	**216**	**19**	**1,852**	**51**	**(56)**	**(1,505)**	**(115)**	**(363)**	**(10,390)**	**(177)**	**(16)**	**(2,255)**	**(18,471)**
38																	
39	Calculation of Income Taxes																
40	Operating Revenue												10,390	177		2,255	12,822
41	-Operating Expense	(2,913)	(724)	(2,072)	216	19	1,852	51	(56)	(1,505)	(111)	(357)			(16)		(5,616)
42	-Amortization																
43	-Taxes Other then Income			(22)							(4)	(6)					(32)
44	Operating Income Before Adjs	2,913	724	2,094	(216)	(19)	(1,852)	(51)	56	1,505	115	363	10,390	177	16	2,255	18,471
45	Additions to Income																
46	Deductions from Income																
47	Debt Synchronization																
48	State Taxable Income	2,913	724	2,094	(216)	(19)	(1,852)	(51)	56	1,505	115	363	10,390	177	16	2,255	18,471
49	State Income Tax Before Credits	285	71	205	(21)	(2)	(181)	(5)	6	148	11	36	1,018	17	2	221	1,810
50	State Tax Credits																
51	Federal Tax Deductions																
52	Federal Taxable Income	2,627	653	1,889	(195)	(17)	(1,670)	(46)	51	1,358	104	327	9,372	160	14	2,034	16,661
53	Federal Income Tax Before Credits	552	137	397	(41)	(4)	(351)	(10)	11	285	22	69	1,968	34	3	427	3,499
54	Federal Tax Credits																
55	Total Income Taxes	837	208	602	(62)	(5)	(532)	(15)	16	433	33	104	2,986	51	5	648	5,309

PRECEDENTIAL ADJUSTMENT DETAIL SCHEDULE
2022 Unadjusted Test Year versus 2022 Adjusted Test Year
($000s)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
		Precedential Adjustments															
Line No.	NSPM - 11 Bridge by Report Label - Precedential Adjustments	NSPM-Advertising	NSPM-Assn Dues	NSPM-Aviation	NSPM-Chamber of Commerce Dues	NSPM-Customer Deposits - A&G Expense	NSPM-Donations	NSPM-Econ Dev Donations	NSPM-Econ Develop	NSPM-Employee Expenses	NSPM-Foundation Admin	NSPM-Investor Relations	NSPM-Monticello EPU Commission Order No Return	NSPM-Nobles Disallowed Assets	NSPM-Nuclear Retention Removal	NSPM-Other Revenue to 3 Year Average Adj	Total
1																	
2	Operating Revenues																
3	Retail Revenue																
4	Other Operating												9,243	163		2,807	12,213
5	Total Revenue												9,243	163		2,807	12,213
6																	
7	Expenses																
8	Operating Expenses																
9	Customer Accounting																
10	Customer Service and Information																
11	Sales, Econ Dev, & Other							52	(56)								(5)
12	Administrative and General	(2,967)	(723)	(2,117)	218	19	1,852			(1,455)	(113)	(359)					(5,645)
13	Total Operating Expenses	(2,967)	(723)	(2,117)	218	19	1,852	52	(56)	(1,455)	(113)	(359)					(5,650)
14																	
15	Depreciation																
16	Amortization																
17																	
18	Taxes																
19	Property																
20	Deferred Income Tax and ITC																
21	Federal and State Income Tax	853	208	615	(63)	(5)	(532)	(15)	16	418	34	105	2,657	47		807	5,143
22	Payroll and Other			(23)							(4)	(6)					(32)
23	Total Taxes	853	208	592	(63)	(5)	(532)	(15)	16	418	30	99	2,657	47		807	5,111
24																	
25	Total Expenses	(2,114)	(516)	(1,524)	155	13	1,320	37	(40)	(1,037)	(83)	(260)	2,657	47		807	(539)
26																	
27	Allowance for Funds Used During Construction																
28																	
29	Net Income	2,114	516	1,524	(155)	(13)	(1,320)	(37)	40	1,037	83	260	6,586	116		2,000	12,752
30																	
31	Calculation of Revenue Requirements																
32	Rate Base																
33	Required Operating Income																
34	Operating Income	2,114	516	1,524	(155)	(13)	(1,320)	(37)	40	1,037	83	260	6,586	116		2,000	12,752
35	Income Deficiency	(2,114)	(516)	(1,524)	155	13	1,320	37	(40)	(1,037)	(83)	(260)	(6,586)	(116)		(2,000)	(12,752)
36	**Revenue Deficiency**	**(2,967)**	**(723)**	**(2,139)**	**218**	**19**	**1,852**	**52**	**(56)**	**(1,455)**	**(117)**	**(365)**	**(9,243)**	**(163)**		**(2,807)**	**(17,895)**
37																	
38	Calculation of Income Taxes																
39	Operating Revenue												9,243	163		2,807	12,213
40	-Operating Expense	(2,967)	(723)	(2,117)	218	19	1,852	52	(56)	(1,455)	(113)	(359)					(5,650)
41	-Amortization																
42	-Taxes Other then Income			(23)							(4)	(6)					(32)
43	Operating Income Before Adjs	2,967	723	2,139	(218)	(19)	(1,852)	(52)	56	1,455	117	365	9,243	163		2,807	17,895
44	Additions to Income																
45	Deductions from Income																
46	Debt Synchronization																
47	State Taxable Income	2,967	723	2,139	(218)	(19)	(1,852)	(52)	56	1,455	117	365	9,243	163		2,807	17,895
48	State Income Tax Before Credits	291	71	210	(21)	(2)	(182)	(5)	6	143	11	36	906	16		275	1,754
49	State Tax Credits																
50	Federal Tax Deductions																
51	Federal Taxable Income	2,676	653	1,930	(196)	(17)	(1,671)	(47)	51	1,312	105	329	8,337	147		2,532	16,142
52	Federal Income Tax Before Credits	562	137	405	(41)	(4)	(351)	(10)	11	276	22	69	1,751	31		532	3,390
53	Federal Tax Credits																
54	Total Income Taxes	853	208	615	(63)	(5)	(532)	(15)	16	418	34	105	2,657	47		807	5,143

Wholesale Customer Study

Purpose

With respect to the costs and revenues related to serving wholesale customers, the Company and the Department of Commerce agreed in the prior rate case (Docket No. E002/GR-15-826) as follows:

> The Company will provide as a compliance filing in future rate cases a wholesale customer study which shows all wholesale customers being served by the Company (including, but not limited to, full requirements, partial requirements, and market based wholesale customers), types of service being provided to each wholesale customer, costs and revenues associated with each wholesale customer, and a clear showing either that wholesale costs are allocated out of the retail rate case or that the revenues are included in the retail rate case, for all services provided to wholesale customers.[1]

This study provides the required information. Information in this study will include the types of services being provided to wholesale customers and the treatment of revenues and margins associated with wholesale customer transactions. The study does not address wholesale transmission revenues, which revenues and associated costs are discussed in detail in the Direct Testimony of Company witness Mr. Ian R. Benson.

All wholesale customers are provided services pursuant to bilateral agreements. These bilateral agreements define the scope of services for each wholesale customer, such as interfacing between the customer and the Midcontinent Independent System Operator, Inc. (MISO), including providing balancing services. Revenues from these customers are included in Other Revenues (e.g., for balancing services), and asset based margins for energy sales are passed through the fuel clause and removed from the cost of service. We also provide some non-asset based services to these customers (energy and capacity sales using financial instruments). Non-asset based margins (revenues less costs), as well as the fully-allocated costs of those activities, are removed from the cost of service.

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[1] May 22, 2013 Issues List, Docket No. E002/GR-12-961.

Historic Wholesale Cost Assignment Method

Through the mid-1990s, the Company provided bundled cost-based "requirements" wholesale services to numerous municipal utilities connected to the NSP transmission system. Total municipal loads were in the hundreds of megawatts. Some wholesale municipal customers were full requirements customers and purchased all of their capacity and energy from the Company. Other municipal customers received "preference power" allocations from the Western Area Power Administration for a portion of their power supply needs and purchased partial requirements service from the Company for the remainder. However, during the 1970s through the 1990s, new municipal power agencies (such as Southern Minnesota Municipal Power Agency, Central Minnesota Municipal Power Agency, Minnesota Municipal Power Agency, etc.) were created to serve the power supply needs of these and other municipal customers, and most of the cost-based requirements wholesale sales agreements expired.

Previously, when municipal power loads were significant, costs were allocated to a wholesale municipal jurisdiction similar to the process used to allocate costs to the Company's retail jurisdictions (Minnesota, North Dakota and South Dakota). Fixed production costs were allocated based on coincident peak demand, and variable production costs were allocated based on the energy allocator. This process also included the direct assignment of some costs to the Wholesale jurisdiction for services being directly provided to those customers (such as distribution transformation services).

In addition, the Company direct-assigned costs where possible or allocated customer accounting, customer information, and sales costs to the jurisdiction based on the number of customers. Similarly, administrative and general (A&G) costs were allocated or direct assigned as appropriate based on functional organization. Specifically, if A&G costs were incurred by the Energy Supply, Commercial Operations or Transmission organizations, they were allocated to retail and wholesale jurisdictions based on the jurisdictional demand allocator.

Changes in Wholesale Market and Test Year Wholesale Customers

As of 2012, the Company directly served only three traditional cost-based requirements wholesale customers: the City of Ada, City of Kasota, and Heartland Consumers Power District (HCPD) for the City of Lake Crystal. These customers comprised less than one-tenth of one percent of total Company demand and energy requirements. The rates and services for sales to these customers were regulated by the Federal Energy Regulatory Commission (FERC) under tariffs or contracts on file with FERC. The contract rates were indexed to the Minnesota Commercial and Industrial (C&I) General Service Retail or Time of Day rates.

However, excess capacity and energy on a short to mid-term basis has increased competition and put downward pressure on pricing. Given the market dynamics, the Company's wholesale customers determined it was in their best interest to purchase energy on the open market rather than continuing service under cost based contracts. Where in the past, these customers mitigated energy cost volatility risk by entering into full requirements agreements with the Company, they now prefer to take on that risk themselves, given the current market environment. Therefore, the Company no longer has any cost-based requirements wholesale customers in the 2020 test year or the 2021 and 2022 plan years.

Services Provided to Wholesale Customers in 2020

The Company provides services to wholesale customers through the execution of transactions that fall into three main categories: Asset Based Transactions, Non-Asset Based Transactions, and Other Wholesale Transactions.

Asset based transactions involve the sale of excess energy and capacity available from Company owned generation assets. Both costs and revenues associated with asset-based energy and capacity transactions are included in the unadjusted retail rate case cost of service, and all margins resulting from asset-based energy sales are excluded from the 2020 test year as they are returned to the ratepayers through the Fuel Clause Adjustment pursuant the Company's 2005 electric rate case (Docket No. E002/GR-05-1428).

Non-asset based transactions are those in which energy and/or capacity is purchased from a third party and resold for profit. Non-asset based transactions are undertaken as energy market opportunities to make revenue and are unrelated to meeting the needs of our retail customers. These transactions are included in the unadjusted retail rate case cost of service. However, the fully allocated costs of non-asset based trading activity are removed from the cost of service study, and all margins (revenues less costs) associated with these activities are also removed and retained by the Company.

The Other Wholesale Transaction category includes transactions related to MISO interfacing services, an energy services agreement with **[PROTECTED DATA**

BEGINS PROTECTED DATA ENDS], and the pass-through of MISO charges to the appropriate parties. The costs of these services are included in the cost of service, and all revenues are recorded as Other Revenue and are credited to retail customers through the cost of service.

Attachment A to this schedule provides a list of the types of services provided, and the ratemaking treatment for each type of service. Attachment B to this schedule provides a wholesale customer summary including all current agreements by customer and the expected revenues for the years 2020-2022.

Test Year Wholesale Transactions

During 2020, the Company expects to engage in wholesale transactions in the following categories: asset based energy sales, asset based capacity sales, non-asset based sales and other wholesale transactions including MISO interface and scheduling services, energy services agreements, and pass through charges. These transactions and their impact on the test year are discussed below.

Asset Based Energy Sales Transactions

Asset based energy sales margins are generated through the sale of available excess energy either directly into the Midcontinent Independent System Operator (MISO) market or to specific wholesale customers through bilateral agreements. Pricing of excess energy sales to MISO are based on prevailing locational marginal prices (LMP) that clear in the Day Ahead or Real Time markets. Pricing of transactions s made directly by the Company to specific wholesale customers is based on the current marginal cost of generation at the time of the transaction, and the Company does not make a margin on these sales. Instead, the Company charges a scheduling fee for providing this service. Therefore, the margin on these sales is equal to the scheduling fee paid by the customer. Net margins earned on all asset based energy sales, including the scheduling fees, are returned to rate payers through the Fuel Clause Adjustment.

Table 1 below shows the asset based energy sales margins for 2018 and 2020. In addition, Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A29 includes all calculations related to asset based transactions and their impact on the test year. The revenues associated with these trades flow through to Other Electric Revenues in the income statement as shown in Workpapers Vol 4, Tab R2 : "SALES FOR RESALE – BILED MKT ASSET REV."

Table 1

Asset Based Energy Sales Transactions

State of Minnesota Jurisdiction	2018	2020 Budget
Revenues	$114.1M	$108.3M
COGS *	($91.7M)	($103.5M)
Margin	**$22.4M**	**$4.8M**

*COGS Information includes Revenue Sharing Thru the FCA

Asset Based Capacity Sales Transactions

Revenues for asset based capacity sales are included in the cost of service and are not included in the asset based margin adjustment (which includes only the net margin for asset based energy sales). These capacity sales revenues, labeled "OTHER ELEC REV – Zonal Resource Credits (ZRC)" and totaling $688,225 are included in Other Electric Revenues in the income statement as shown in Workpapers Vol 4, Tab R5.

Non-Asset Based Transactions

Non-asset based transactions are not included in the retail rate case: revenues and their associated fully allocated embedded costs are removed from the cost of service, and all margins are retained by the Company pursuant to the settlement in the Company's 2011 rate case (Docket No. E002/GR-10-971) . These adjustments are discussed by Company witness Mr. Benjamin C. Halama in his Direct Testimony, Section VII, Adjustments to the Test Year.

Other Wholesale Transactions

This category includes the three types of wholesale customer agreements not included in the asset based and non-asset based categories: MISO Interface/Scheduling, Energy Services Agreements, and Pass Through Charges (for a detailed explanation of each category, please see Attachment A to this schedule). In each case, revenues and costs associated with these transactions are included in the rate case, and no adjustment is made to the income statement or cost of service. As shown in Attachment B to this schedule, revenues from Other Wholesale Transactions are expected to be $583,115 in 2020. These revenues flow into Other Operating Revenue as shown in Workpapers Vol 4, Tab R1, labeled "OTHER ELEC REV ."

Conclusions

After reviewing the services anticipated to be provided to wholesale customers in 2020 and the transactions associated with those services, the Company concludes that the ratemaking treatment of these transactions is consistent with existing regulatory practices:

- Wholesale transaction costs and revenues are held above the line except with respect to non-asset based transactions
    - Non-asset based margins are adjusted out of the test year and retained by the Company
    - Non-asset based trading costs are adjusted out of the test year, reducing the revenue requirement
- Asset based energy sales margins are shared with rate payers through the Fuel Clause Adjustment
- Other Wholesale Transactions are included in the test year and offset revenue requirements

The Company does not recommend any changes to the treatment of wholesale customers or the revenues and costs associated with providing these services. In addition, the Company concludes that there are no adverse impacts on ratepayers as a result of providing these services or the ratemaking treatment of the associated transactions.

PUBLIC DOCUMENT – NOT-PUBLIC DATA HAS BEEN EXCISED

Deal Category	Deal Type	Scope of Services	Ratemaking Treatment
Energy	Asset Based Energy Sale	These Asset Based Energy deals are for the sale of energy generated by NSP's own assets. The quantity is scheduled by mutual agreement. NSP earns either a fixed monthly fee or per MWh scheduling fee over and above the cost of energy. The quantity is determined based upon forecasted volumes which may vary from actual usage.	**Asset Based - Fuel Clause Adjustment** 100% of the margins are returned to ratepayers through the Fuel Clause Adjustment
	Non-Asset Based Energy Sale	A Non-Asset Based Energy deal is for the sale of a specified quantity of MWh at a given price throughout the contract term. The energy sold to the counterparty is not generated by NSP's own assets. Instead NSP either (1) purchases a like product to back all or a part of the position and/or (2) purchases the requisite energy off the MISO market day ahead or in real time depending upon risk tolerance. Business Rules require that any purchase or sale of energy be offered to the NSP system first. If the system passes on the purchase or sale it can then be assigned to the prop book.	**Non-Asset Based - Margin Adjustment** Margins are retained by the Company. Therefore, both the margins and the associated O&M costs are excluded from the test year
Capacity	Asset Based Capacity Sale	An Asset Based Capacity deal is for the sale of MISO Zonal Resource Credits ("ZRCs", which are fungible instruments that represent one MW of Unforced Capacity from a Planning Resource over a MISO planning year). For these deals, the capacity sold is provided by NSP's projected surplus assets.	**Asset Based - No Adjustment** Revenues are included as an offset to the revenue requirement. Associated fixed costs are included in the Cost of Service Study.
	Non-Asset Based Capacity Sale	A Non-Asset Based Capacity deal is for the sale of MISO ZRCs that are backed by the purchase of a like product. Business Rules require that any purchase or sale of capacity be offered to the NSP system first. If the system passes on the purchase or sale it can then be assigned to the prop book	**Non-Asset Based - Margin Adjustment** Margins are retained by the Company. Therefore, both the margins and the costs are excluded from the test year
Other	MISO Interface/Scheduling	In a MISO Interface deal NSP provides services necessary for the counterparty to operate in the MISO market. Such services include Day Ahead load bids, FinScheds, Capacity reporting for MISO Module E, and others as specified in the individual contracts. Pricing is determined on a per MWh basis and may vary depending upon actual usage.	**Other Wholesale Transactions - No Adjustment** Revenues are included as an offset to the revenue requirement. Associated O&M costs are included in the Cost of Service Study.
	Energy Services Agreement	The Company currently has only one Energy Services Agreement in place. This deal governs the fee paid to NSP for the preservation of transmission reservations, which improves **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** ability to import and export power. The annual service fee payments are payable to NSP in advance of the service year.	**Other Wholesale Transactions - No Adjustment** Revenues are included as an offset to the revenue requirement. Associated O&M costs are included in the Cost of Service Study.
	MISO Pass Through	These pass through arrangements specify that all MISO charges including transmission service, congestion AND loss, and ancillary services are a pass through. NSP earns no margin on such deals.	**N/A** There are no revenues or expenses requiring ratemaking treatment as these transactions are merely a pass through of MISO charges.

NSP Wholesale Customer Summary
as of July 24, 2019

Background information

Energy deals

Gen book sales

A deal in the gen book energy column (i.e. NWEC partial requirements) is for the sale of energy that is generated by NSP's own assets. The quantity is scheduled by the counterparty for use as an intermediate/peaking resource. NSP earns either a fixed monthly fee or per MWh scheduling fee over and above the cost of energy. The margin for these deals is determined based upon forecasted volumes and may vary depending upon actual usage.

Prop book sales

A deal in the prop book energy column (i.e. Ada energy) is for the sale of a specified quantity of MWs at a given price throughout the contract term. The energy sold to the counterparty is not generated by NSP's own assets. Instead NSP either (1) purchases a like product to back the position (a bilateral deal) or (2) purchases the requisite energy off the MISO market (a market based deal).

Capacity deals

Gen book

A deal in the gen book capacity column (i.e. Ada capacity) is for the sale of MISO Zonal Resource Credits ("ZRCs", which are fungible instruments that represent one MW of Unforced Capacity from a Planning Resource over a MISO planning year). For these deals, the capacity sold is provided by NSP's projected surplus assets.

Prop book

A deal in the prop book capacity deals column (i.e. Basin Electric capacity) is for the sale of MISO ZRCs that are backed by the purchase of a like product.

Other deals

MISO interface/scheduling

A deal in the MISO interface services & scheduling fees column (i.e. Ada energy) is for NSP providing services necessary for the counterparty to operate in the MISO market. Such services include Day Ahead load bids, FinScheds, Capacity reporting for MISO Module E, and others as specified in the individual contracts. Pricing is determined on a per MWh basis and may vary depending upon actual usage.

Energy services agreement

Pass through charges

A deal in the pass through charges column (i.e. Ada energy) is to specify that all MISO charges including transmission service, congestion & loss, and ancillary services are a pass through. NSP earns no margin on such deals.

2020

Counterparty	Contract term	Energy: Gen: partial requirements 3	Energy: Prop: bilateral or market based	Capacity: Gen capacity	Capacity: Prop capacity	Other: MISO interface svcs & Scheduling Fees	Other: Energy services agreement	Other: Pass through charges
Revenues								
Ada	1/1/17-12/31/21		1			A		2
Ada	1/1/17-12/31/21			A				
Ada	1/1/12-12/31/27							
Kasota	1/1/17-12/31/21		1			A		2
Kasota	1/1/17-12/31/21			A				
Kasota	1/1/22-12/31/27							
NWEC	5/1/15 - 12/31/20	B	1			A		
NWEC	1/1/21 - 12/31/21							
NWEC	6/1/19 - 5/31/20			A				
NCP	5/1/15 - 12/31/20	B	1			A		
NCP	1/1/21 - 12/31/21							
NCP	6/1/19 - 5/31/20			A				
Dahlberg Light & Power Co.	1/1/17 - 12/31/27					A		
Dahlberg Light & Power Co.	1/1/14 - 12/31/27	B	1					
Dahlberg Light & Power Co.	6/1/19 - 5/31/20			A				
							A	
							A	
Great Lakes Utilities	6/1/20 - 5/31/21			A				
Costs								
Ada	1/1/17-12/31/21		1			5 & 8		2
Ada	1/1/17-12/31/21			4				
Ada	1/1/12-12/31/27					5 & 8		2
Kasota	1/1/17-12/31/21		1			5 & 8		2
Kasota	1/1/17-12/31/21			4				
Kasota	1/1/22-12/31/27							
NWEC	5/1/15 - 12/31/20		1				6	
NWEC	1/1/21 - 12/31/21							
NWEC	6/1/19 - 5/31/20							
NCP	5/1/15 - 12/31/20		1				6	
NCP	1/1/21 - 12/31/21							
NCP	6/1/19 - 5/31/20							
Dahlberg Light & Power Co.	1/1/17 - 12/31/27					5	6	
Dahlberg Light & Power Co.	1/1/14 - 12/31/27		1					
Dahlberg Light & Power Co.	6/1/19 - 5/31/20							
								2
								2
Great Lakes Utilities	6/1/20 - 5/31/21							

2021

Counterparty	Contract term	Energy: Gen: partial requirements 3	Energy: Prop: bilateral or market based	Capacity: Gen capacity	Capacity: Prop capacity	Other: MISO interface svcs & Scheduling Fees	Other: Energy services agreement	Other: Pass through charges
Revenues								
Ada	1/1/17-12/31/21		1			A		2
Ada	1/1/17-12/31/21			A				
Ada	1/1/12-12/31/27							
Kasota	1/1/17-12/31/21		1			A		2
Kasota	1/1/17-12/31/21			A				
Kasota	1/1/22-12/31/27							
NWEC	5/1/15 - 12/31/20							
NWEC	1/1/21 - 12/31/21	B	1			A		
NWEC	6/1/19 - 5/31/20							
NCP	5/1/15 - 12/31/20							
NCP	1/1/21 - 12/31/21	B	1			A		
NCP	6/1/19 - 5/31/20							
Dahlberg Light & Power Co.	1/1/17 - 12/31/27					A		
Dahlberg Light & Power Co.	1/1/14 - 12/31/27	B	1					
Dahlberg Light & Power Co.	6/1/19 - 5/31/20							
								A
								A
Great Lakes Utilities	6/1/20 - 5/31/21			A				
Costs								
Ada	1/1/17-12/31/21		1			5 & 8		2
Ada	1/1/17-12/31/21			4				
Ada	1/1/12-12/31/27					5 & 8		2
Kasota	1/1/17-12/31/21		1			5 & 8		2
Kasota	1/1/17-12/31/21			4				
Kasota	1/1/22-12/31/27							
NWEC	5/1/15 - 12/31/20							
NWEC	1/1/21 - 12/31/21		1				6	
NWEC	6/1/19 - 5/31/20							
NCP	5/1/15 - 12/31/20							
NCP	1/1/21 - 12/31/21		1				6	
NCP	6/1/19 - 5/31/20							
Dahlberg Light & Power Co.	1/1/17 - 12/31/27					5	6	
Dahlberg Light & Power Co.	1/1/14 - 12/31/27		1					
Dahlberg Light & Power Co.	6/1/19 - 5/31/20							
								2
								2
Great Lakes Utilities	6/1/20 - 5/31/21							

2022

Counterparty	Contract term	Energy: Gen: partial requirements 3	Energy: Prop: bilateral or market based	Capacity: Gen capacity	Capacity: Prop capacity	Other: MISO interface svcs & Scheduling Fees	Other: Energy services agreement	Other: Pass through charges
Revenues								
Ada	1/1/17-12/31/21							
Ada	1/1/17-12/31/21							
Ada	1/1/12-12/31/27		1			A		2
Kasota	1/1/17-12/31/21		1					
Kasota	1/1/17-12/31/21							
Kasota	1/1/22-12/31/27		1			A		2
NWEC	5/1/15 - 12/31/20							
NWEC	1/1/21 - 12/31/21							
NWEC	6/1/19 - 5/31/20							
NCP	5/1/15 - 12/31/20							
NCP	1/1/21 - 12/31/21							
NCP	6/1/19 - 5/31/20							
Dahlberg Light & Power Co.	1/1/17 - 12/31/27					A		
Dahlberg Light & Power Co.	1/1/14 - 12/31/27	B	1					
Dahlberg Light & Power Co.	6/1/19 - 5/31/20							
								A
								A
Great Lakes Utilities	6/1/20 - 5/31/21							
Costs								
Ada	1/1/17-12/31/21					5 & 8		2
Ada	1/1/17-12/31/21			4				
Ada	1/1/12-12/31/27		1			5 & 8		2
Kasota	1/1/17-12/31/21		1			5 & 8		2
Kasota	1/1/17-12/31/21			4				
Kasota	1/1/22-12/31/27							
NWEC	5/1/15 - 12/31/20							
NWEC	1/1/21 - 12/31/21							
NWEC	6/1/19 - 5/31/20							
NCP	5/1/15 - 12/31/20							
NCP	1/1/21 - 12/31/21							
NCP	6/1/19 - 5/31/20							
Dahlberg Light & Power Co.	1/1/17 - 12/31/27					5	6	
Dahlberg Light & Power Co.	1/1/14 - 12/31/27		1					
Dahlberg Light & Power Co.	6/1/19 - 5/31/20							
								2
								2
Great Lakes Utilities	6/1/20 - 5/31/21							

1 NSPM's proprietary book budget after joint operating agreement for 2020-2022 is targeted at $6.3M, $8M, and $8.3M respectively. This transaction is part of the proprietary budget target however we do not specifically identify the revenue and cost of the deals, therefore this information is not presented within this analysis. The margin of this transaction is not shared with Minnesota.

2 All MISO charges including transmission service, congestion & loss, and ancillary services are passed through to the customer. These charges are variable on a monthly basis and are not forecasted. Due to the pass-through process, income is equal to cost and there is no incremental margin to NSP.

3 These generation book partial requirements customers purchase energy at Time of Day rates and are charged either a fixed monthly scheduling fee or a fee based upon MWhs scheduled. Accordingly, the revenue and cost associated with the energy will fluctuate in accordance with market prices but will not impact the margin on the deals. The margin will always be the scheduling fee on these deals. Therefore, the revenue shown above is only the scheduling fee margin (which is shared 100% with ratepayers) and cost information is not presented.

4 The cost for generation book capacity is embedded within the cost of fuel for NSP and is not specifically identified.

5 The cost for MISO interface services is embedded within operating expense for NSP and is not specifically identified.

6 The cost for the energy services agreement with Manitoba Hydro is embedded within operating expense for NSP and is not specifically identified.

7 N/A

8 Both the Ada & Kasota Agreements were extended from 2017-2021, which result in revenues in the Gen Capacity and Energy Service Agreements. Gen Capacity revenues past 2018 will be priced on an annual basis.

A This amount agrees to either the "NSP Capacity ZRC Revenue" or "NSP Service Fee Revenue" budget file without exception.

B The budgeted gen book margin for 2020 - 2022 is $54M, $51M, and $56M respectively. The budgeted amounts are a subset of this budget and are not budgeted on a contract by contract basis.

C These amounts are not included in the 2020 - 2022 budget due to timing of deal execution (i.e. deal was executed after preparation of 2020-2022 budget)

CAPACITY COST STUDY
NSP Summary

Long-Term Purchased Power Capacity Cost Forecast by Contract - Minnesota 2020 Rate Case Filing

	Byllesby 1	Byllesby 2	Hastings	LSP	MH.Part	Rapidan*	St.Cloud	Mankato	Mankato II**	Cannon Falls	Total $000
2020 Jan											-
2020 Feb											-
2020 Mar											-
2020 Apr											-
2020 May											-
2020 Jun											-
2020 Jul											-
2020 Aug											-
2020 Sep											-
2020 Oct											-
2020 Nov											-
2020 Dec											-
2021 Jan											-
2021 Feb											-
2021 Mar											-
2021 Apr											-
2021 May											-
2021 Jun											-
2021 Jul											-
2021 Aug											-
2021 Sep											-
2021 Oct											-
2021 Nov											-
2021 Dec											-
2022 Jan											-
2022 Feb											-
2022 Mar											-
2022 Apr											-
2022 May											-
2022 Jun											-
2022 Jul											-
2022 Aug											-
2022 Sep											-
2022 Oct											-
2022 Nov											-
2022 Dec											-
2020											147,899
2021											153,403
2022											159,427

*The contract with Rapidan terminates Jan 31, 2020
***The contract with Makato II begins in June 1, 2019

Description of Terms in Following Pages (as per DOC IR-041 in Docket No. E002/GR-12-961):

Demand Rate	Specifies the rate that is paid per unit of capacity that is purchased.
FOM Rate	Fixed Operations and Maintenance rate; defined in each contract.
Capacity Factor Adjustment	Lowers the capacity payment if the facility is producing below a capacity factor of 70% as defined in the contract.
Fuel Inventory Rate	Defined in contracts and is fixed for the term of the agreement.
FR1	Fixed rate as defined by contract
FR2	Fixed rate as defined by contract
FR3	Fixed rate as defined by contract
AF1	Adjustment Factor-1 as defined by contract
BF1	Bonus Factor - 1 as defined by contract
CLF	Capacity Loss Factor as defined by contract
CTUP	Capacity True-Up Payment
CCTF	Committed Capacity True-up Factor based on the Tested Capacity Ratio (TCR) determined by the Committed Capacity Test

Calculation Maps are included for each following page.

CAPACITY COST STUDY
NSP Summary

	A	B	C	D = A+B+C	E	F	D*E*F/1000
	Demand Rate $/kW-mo	Fuel Inventory $/kW-mo	FOM Rate $/kW-mo	Committed Capacity Rate $/kW-mo	Committed Capacity kW	Losses %	Total Demand $000
2020 Jan							
2020 Feb							
2020 Mar							
2020 Apr							
2020 May							
2020 Jun							
2020 Jul							
2020 Aug							
2020 Sep							
2020 Oct							
2020 Nov							
2020 Dec							
2021 Jan							
2021 Feb							

CAPACITY COST STUDY
NSP Summary

	A	B	C	D = A+B+C	E	F	D*E*F/1000
	Demand Rate $/kW-mo	Fuel Inventory $/kW-mo	FOM Rate $/kW-mo	Committed Capacity Rate $/kW-mo	Committed Capacity kW	Losses %	Total Demand $000
2020 Jan							
2020 Feb							
2020 Mar							
2020 Apr							
2020 May							
2020 Jun							
2020 Jul							
2020 Aug							
2020 Sep							
2020 Oct							
2020 Nov							
2020 Dec							
2021 Jan							
2021 Feb							

CAPACITY COST STUDY
NSP Summary

	A	B	C = A+B	D	F	C*D*F/1000
	Demand Rate $/kW-mo	FOM Rate $/kW-mo	Total Demand Rate $/kW-mo	Committed Capacity kW	Capacity Factor Adjustment	Total Demand $000
2020 Jan						
2020 Feb						
2020 Mar						
2020 Apr						
2020 May						
2020 Jun						
2020 Jul						
2020 Aug						
2020 Sep						
2020 Oct						
2020 Nov						
2020 Dec						
2021 Jan						
2021 Feb						
2021 Mar						
2021 Apr						
2021 May						
2021 Jun						
2021 Jul						
2021 Aug						
2021 Sep						
2021 Oct						
2021 Nov						
2021 Dec						
2022 Jan						
2022 Feb						
2022 Mar						
2022 Apr						
2022 May						
2022 Jun						
2022 Jul						
2022 Aug						
2022 Sep						
2022 Oct						
2022 Nov						
2022 Dec						

CAPACITY COST STUDY
NSP Summary

	A	B	C	D = B*C	E	F	G	H	I	J	K	L = (A*(D+E+F)*G*H*I*K+J)/12/1000	M	L-M
	kW	FR1 rate ($/kW-Yr)	FR1 Adjustment factor	FR1 adjusted ($/kW-Yr)	FR2 rate ($/kW-Yr)	FR3 rate ($/kW-Yr)	AF1	BF1	CLF	CTUP	CCTF	Demand Charge $000	Monthly Reduction in Capacity payment	Final Demand Charge $000
2020 Jan														
2020 Feb														
2020 Mar														
2020 Apr														
2020 May														
2020 Jun														
2020 Jul														
2020 Aug														
2020 Sep														
2020 Oct														
2020 Nov														
2020 Dec														
2021 Jan														
2021 Feb														
2021 Mar														
2021 Apr														
2021 May														
2021 Jun														
2021 Jul														
2021 Aug														
2021 Sep														
2021 Oct														
2021 Nov														
2021 Dec														
2022 Jan														
2022 Feb														
2022 Mar														
2022 Apr														
2022 May														
2022 Jun														
2022 Jul														
2022 Aug														
2022 Sep														
2022 Oct														
2022 Nov														
2022 Dec														

CAPACITY COST STUDY
NSP Summary
Purchaser: Northern States Power Company
Seller: The Manitoba Hydro -Electric Board (PPA dated May 27, 2010)

CAPACITY COST STUDY
NSP Summary

	A	B	C	D = A+B+C	E	F = D*E/1000	G	H	I = G*H/1000	F+I
2020 Jan										
2020 Feb										
2020 Mar										
2020 Apr										
2020 May										
2020 Jun										
2020 Jul										
2020 Aug										
2020 Sep										
2020 Oct										
2020 Nov										
2020 Dec										
2021 Jan										
2021 Feb										
2021 Mar										
2021 Apr										

CAPACITY COST STUDY
NSP Summary

	A	B	C	D = A+B+C	E	F	D*E*F/1000-4.16667
2020 Jan							
2020 Feb							
2020 Mar							
2020 Apr							
2020 May							
2020 Jun							
2020 Jul							
2020 Aug							
2020 Sep							
2020 Oct							
2020 Nov							
2020 Dec							
2021 Jan							
2021 Feb							
2021 Mar							
2021 Apr							
2021 May							
2021 Jun							
2021 Jul							
2021 Aug							
2021 Sep							
2021 Oct							
2021 Nov							
2021 Dec							
2022 Jan							
2022 Feb							
2022 Mar							
2022 Apr							
2022 May							
2022 Jun							
2022 Jul							
2022 Aug							
2022 Sep							
2022 Oct							
2022 Nov							
2022 Dec							

CAPACITY COST STUDY
NSP Summary
Purchaser: Northern States Power
Seller: Mankato Energy Center, LLC (Purchased Power Agreement dated March 11, 2004)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	**2020**	**2021**	**2022**

Contract Capacity Payment Factors:

2020 Fixed Charges:	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total

CAPACITY COST STUDY
NSP Summary
Purchaser: Northern States Power
Seller: Mankato Energy Center II, LLC (Purchased Power Agreement dated xx/xx/xx)

	1	2	3	4	5	6	7	8	9	10	11	12	13
	6/1/19-5/31/20	6/1/20-5/31/21	6/1/21-5/31/22	6/1/22-5/31/23	6/1/23-5/31/24	6/1/24-5/31/25	6/1/25-5/31/26	6/1/26-5/31/27	6/1/27-5/31/28	6/1/28-5/31/29	6/1/29-5/30/30	6/1/30-5/31/31	6/1/31-5/31/32

Contract Capacity Payment Factors:

2020 Fixed Charges:	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total

CAPACITY COST STUDY
NSP Summary
Purchaser: Northern States Power
Seller: Invenergy Cannon Falls, LLC - Cannon Falls Energy Center

Expected Start Date:
Expected Termination Date:

Contracted Capacity (Net Capability) - KW:

Net Dependable Capability:

Fixed Charge Prices:	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	**2020**	**2021**	**2022**

Fixed Charge Factors:

Fixed Charges - 2020:	January	February	March	April	May	June	July	August	September	October	November	December	Annual Total
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Economic Development Analysis - Commercial Inputs

2020 Economic Development

Average Cost for Industrial/Commercial installation of 500KVA Txfs.	$	37,000	Schedule 16, Attachment B, Line 1
Annual Revenue per Customer	$	146,461	Schedule 16, Attachment B, Line 23
Total Economic Development Expenses in Test Year	$	56,203	Schedule 16, Attachment B, Line 18
Other Revenue Requirements Associated with Additional ED Customer	$	19,175	Schedule 16, Attachment B, Lines 16, 19, 20, 21
Total Revenue Requirements	$	75,378	Schedule 16, Attachment B, Line 22
Potential Customer Benefit in Year 1	$	71,082	Schedule 16, Attachment B, Line 24
Potential Cumulative Customer Benefit over Life of Investment	$	1,459,041	Schedule 16, Attachment B, Line 26

Economic Development Analysis - Commercial Inputs

2020 Economic Development Program Cost Benefit Analysis

Growth Program Cost Only | Yes | Enter "Yes" for Growth Program Cost Only Analysis
Total Economic Development Costs | No

Present Commercial Distribution Rates:
Annual Revenue per Customer $ 146,461 Margin & Customer charge only, no fuel, no rider revenues

ED Program Customer results	1	customers
Average Annual Use per Customer	2,190,000	kWh
kWh Monthly demand billing unit	500	kW
Assumed Total ED Program Result	2,190,000	kWh

Ave Cost for Inductrial/Commercial Jobs involving the installation of 500KVA Txfs.
$ 37,000

Book Life - transformers	32	years
Negative Salvage	-10.0%	cost of removal
Book Depreciation Rate	3.438%	
Tax Depreciation Rate	MACRS Depreciation Tables - 20 year recovery	

Composite Tax Rate 28.74%

Total Economic Development Costs	$ 56,203
Total ED Costs for all Customers	$ 56,203
Cumulative NPV Revenue Requirement	$ 1,459,041

Preliminary Cost of Capital - Electric Case Filing

	Cost	Weight	Weighted Cost of Capital	
Equity	9.20%	52.50%	4.83%	Last Authorized Cost of Capital per E002/GR-15-826
Preferred Stock	0.00%	0.00%	0.00%	Last Authorized Cost of Capital per E002/GR-15-826
Long-term Debt	4.75%	45.81%	2.18%	Last Authorized Cost of Capital per E002/GR-15-826
Short-term Debt	4.31%	1.69%	0.07%	Last Authorized Cost of Capital per E002/GR-15-826
		100.00%	7.08%	

MN Composite Income Tax Rate 28.74%

Pre-tax Rate of Return 9.03%

Extension Operating & Maintenance Factor 2.73%
MN Gas Rate Book - Sec. 6, 1st Rev. Sht No. 17.1

Annual Escalation Rate - Chained Price Index-Gross Domestic Product (source: biennual CIP Recovery Factor Filing
(BENCOST) MN Office of Energy Security "OES") 3.59%

Property Tax Rate 1.672%
Hennepin County Electric Rate: 2018 Property Tax Table

Societal Perception:
Electric environmental damage based on environmental damage factor of $6.00 / MWh from Xcel Energy Resource Planning.
MWh/kWh 0.001 $ 6.00 MWh
3.59%

Economic Development - Commercial - with Societal Perspective

Net Present Value of Cash Flows

Line No.		Placed in Service 1	Extension Year No. 2	Extension Year No. 3	Extension Year No. 4	Extension Year No. 5	Extension Year No. 6	Extension Year No. 7
	REVENUE REQUIREMENTS ANALYSIS:							
1	Total Cost	$ 37,000						
2								
3								
4	Total cost:	$ 37,000						
5	Beginning Balance	$ 37,000						
6	Depreciation Expense (including negative salvage)	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272
7	Ending Balance - Net Plant	$ 35,728	$ 34,456	$ 33,184	$ 31,913	$ 30,641	$ 29,369	$ 28,097
8	Average Net Plant	$ 36,364	$ 35,092	$ 33,820	$ 32,548	$ 31,277	$ 30,005	$ 28,733
9	Tax Depreciation Rate	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%
10	Tax Depreciation Amount	$ 1,388	$ 2,671	$ 2,470	$ 2,285	$ 2,114	$ 1,955	$ 1,809
11	Book - Tax Depreciation Difference	$ (116)	$ (1,399)	$ (1,199)	$ (1,014)	$ (842)	$ (684)	$ (537)
12	Cumulative Difference	$ (116)	$ (1,515)	$ (2,713)	$ (3,727)	$ (4,569)	$ (5,253)	$ (5,789)
13	Accumulated Deferred Income Taxes (ADIT)	$ (33)	$ (435)	$ (780)	$ (1,071)	$ (1,313)	$ (1,510)	$ (1,664)
14	Average ADIT	$ (17)	$ (234)	$ (608)	$ (926)	$ (1,192)	$ (1,411)	$ (1,587)
15	Rate Base	$ 36,347	$ 34,858	$ 33,213	$ 31,623	$ 30,084	$ 28,593	$ 27,146
16	Return Requirement @ Pre-tax cost of capital	$ 3,282	$ 3,148	$ 2,999	$ 2,856	$ 2,717	$ 2,582	$ 2,451
17	Distribution Costs:							
18	Economic Development Net Donations	$ 56,203						
	Societal Perspective - Net Benefit (Envrio Damage Costs - externalities)	$ 13,612	$ 14,100	$ 14,607	$ 15,131	$ 15,674	$ 16,237	$ 16,820
19	System Operating and Maintence Costs	$ 1,009	$ 1,046	$ 1,083	$ 1,122	$ 1,162	$ 1,204	$ 1,247
20	Depreciation Expense	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272
21	Property Taxes	$ -	$ 619	$ 641	$ 664	$ 688	$ 712	$ 738
22	Total Revenue Requirement	$ 75,378	$ 20,184	$ 20,601	$ 21,044	$ 21,513	$ 22,007	$ 22,528
23	Customer Non-Energy Revenues at proposed rates	$ 146,461	$ 146,461	$ 146,461	$ 146,461	$ 146,461	$ 146,461	$ 146,461
24	Revenue Excess (Deficiency)	$ 71,082	$ 126,277	$ 125,859	$ 125,417	$ 124,948	$ 124,454	$ 123,933
25	NPV of annual revenue excess (deficiency) @ Overall Return	$ 66,383	$ 110,130	$ 102,509	$ 95,394	$ 88,754	$ 82,558	$ 76,776
26	Cumulative NPV	$ 66,383	$ 176,513	$ 279,022	$ 374,416	$ 463,170	$ 545,728	$ 622,504

Economic Development - Commercial - with Societal Perspective

Net Present Value of Cash Flows

Line No.		Extension Year No. 8	Extension Year No. 9	Extension Year No. 10	Extension Year No. 11	Extension Year No. 12	Extension Year No. 13	Extension Year No. 14
	REVENUE REQUIREMENTS ANALYSIS:							
1	Total Cost							
2								
3								
4	Total cost:							
5	Beginning Balance							
6	Depreciation Expense (including negative salvage)	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272
7	Ending Balance - Net Plant	$ 26,825	$ 25,553	$ 24,281	$ 23,009	$ 21,738	$ 20,466	$ 19,194
8	Average Net Plant	$ 27,461	$ 26,189	$ 24,917	$ 23,645	$ 22,373	$ 21,102	$ 19,830
9	Tax Depreciation Rate	4.522%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%
10	Tax Depreciation Amount	$ 1,673	$ 1,651	$ 1,651	$ 1,651	$ 1,651	$ 1,651	$ 1,651
11	Book - Tax Depreciation Difference	$ (401)	$ (379)	$ (379)	$ (379)	$ (379)	$ (379)	$ (379)
12	Cumulative Difference	$ (6,190)	$ (6,570)	$ (6,948)	$ (7,327)	$ (7,706)	$ (8,085)	$ (8,464)
13	Accumulated Deferred Income Taxes (ADIT)	$ (1,779)	$ (1,888)	$ (1,997)	$ (2,106)	$ (2,215)	$ (2,324)	$ (2,433)
14	Average ADIT	$ (1,722)	$ (1,834)	$ (1,943)	$ (2,052)	$ (2,160)	$ (2,269)	$ (2,378)
15	Rate Base	$ 25,739	$ 24,355	$ 22,975	$ 21,594	$ 20,213	$ 18,832	$ 17,451
16	Return Requirement @ Pre-tax cost of capital	$ 2,324	$ 2,199	$ 2,075	$ 1,950	$ 1,825	$ 1,701	$ 1,576
17	Distribution Costs:							
18	Economic Development Net Donations							
	Societal Perspective - Net Benefit (Envrio Damage Costs - externalities)	$ 17,424	$ 18,049	$ 18,697	$ 19,368	$ 20,064	$ 20,784	$ 21,530
19	System Operating and Maintence Costs	$ 1,292	$ 1,338	$ 1,386	$ 1,436	$ 1,488	$ 1,541	$ 1,597
20	Depreciation Expense	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272
21	Property Taxes	$ 764	$ 792	$ 820	$ 850	$ 880	$ 912	$ 945
22	Total Revenue Requirement	$ 23,076	$ 23,650	$ 24,250	$ 24,876	$ 25,529	$ 26,209	$ 26,919
23	Customer Non-Energy Revenues at proposed rates	$ 146,461	$ 146,461	$ 146,461	$ 146,461	$ 146,461	$ 146,461	$ 146,461
24	Revenue Excess (Deficiency)	$ 123,385	$ 122,810	$ 122,211	$ 121,585	$ 120,932	$ 120,252	$ 119,542
25	NPV of annual revenue excess (deficiency) @ Overall Return	$ 71,383	$ 66,353	$ 61,663	$ 57,291	$ 53,216	$ 49,418	$ 45,878
26	Cumulative NPV	$ 693,888	$ 760,240	$ 821,904	$ 879,195	$ 932,411	$ 981,828	$ 1,027,706

Economic Development - Commercial - with Societal Perspective

Net Present Value of Cash Flows

Line No.		Extension Year No. 15	Extension Year No. 16	Extension Year No. 17	Extension Year No. 18	Extension Year No. 19	Extension Year No. 20	Extension Year No. 21
	REVENUE REQUIREMENTS ANALYSIS:							
1	Total Cost							
2								
3								
4	Total cost:							
5	Beginning Balance							
6	Depreciation Expense (including negative salvage)	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272
7	Ending Balance - Net Plant	$ 17,922	$ 16,650	$ 15,378	$ 14,106	$ 12,834	$ 11,563	$ 10,291
8	Average Net Plant	$ 18,558	$ 17,286	$ 16,014	$ 14,742	$ 13,470	$ 12,198	$ 10,927
9	Tax Depreciation Rate	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	2.231%
10	Tax Depreciation Amount	$ 1,651	$ 1,651	$ 1,651	$ 1,651	$ 1,651	$ 1,651	$ 825
11	Book - Tax Depreciation Difference	$ (379)	$ (379)	$ (379)	$ (379)	$ (379)	$ (379)	$ 446
12	Cumulative Difference	$ (8,843)	$ (9,222)	$ (9,601)	$ (9,979)	$ (10,358)	$ (10,737)	$ (10,291)
13	Accumulated Deferred Income Taxes (ADIT)	$ (2,542)	$ (2,650)	$ (2,759)	$ (2,868)	$ (2,977)	$ (3,086)	$ (2,958)
14	Average ADIT	$ (2,487)	$ (2,596)	$ (2,705)	$ (2,814)	$ (2,923)	$ (3,032)	$ (3,022)
15	Rate Base	$ 16,071	$ 14,690	$ 13,309	$ 11,928	$ 10,548	$ 9,167	$ 7,905
16	Return Requirement @ Pre-tax cost of capital	$ 1,451	$ 1,326	$ 1,202	$ 1,077	$ 952	$ 828	$ 714
17	Distribution Costs:							
18	Economic Development Net Donations							
	Societal Perspective - Net Benefit (Envrio Damage Costs - externalities)	$ 22,303	$ 23,104	$ 23,933	$ 24,792	$ 25,682	$ 26,604	$ 27,559
19	System Operating and Maintence Costs	$ 1,654	$ 1,713	$ 1,775	$ 1,838	$ 1,904	$ 1,973	$ 2,044
20	Depreciation Expense	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272
21	Property Taxes	$ 978	$ 1,014	$ 1,050	$ 1,088	$ 1,127	$ 1,167	$ 1,209
22	Total Revenue Requirement	$ 27,658	$ 28,429	$ 29,231	$ 30,067	$ 30,938	$ 31,844	$ 32,798
23	Customer Non-Energy Revenues at proposed rates	$ 146,461	$ 146,461	$ 146,461	$ 146,461	$ 146,461	$ 146,461	$ 146,461
24	Revenue Excess (Deficiency)	$ 118,803	$ 118,032	$ 117,230	$ 116,394	$ 115,523	$ 114,617	$ 113,663
25	NPV of annual revenue excess (deficiency) @ Overall Return	$ 42,580	$ 39,506	$ 36,643	$ 33,977	$ 31,493	$ 29,180	$ 27,024
26	Cumulative NPV	$ 1,070,286	$ 1,109,792	$ 1,146,436	$ 1,180,412	$ 1,211,905	$ 1,241,085	$ 1,268,108

Economic Development - Commercial - with Societal Perspective

Net Present Value of Cash Flows

Line No.		Extension Year No. 22	Extension Year No. 23	Extension Year No. 24	Extension Year No. 25	Extension Year No. 26	Extension Year No. 27	Extension Year No. 28
	REVENUE REQUIREMENTS ANALYSIS:							
1	Total Cost							
2								
3								
4	Total cost:							
5	Beginning Balance							
6	Depreciation Expense (including negative salvage)	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272
7	Ending Balance - Net Plant	$ 9,019	$ 7,747	$ 6,475	$ 5,203	$ 3,931	$ 2,659	$ 1,388
8	Average Net Plant	$ 9,655	$ 8,383	$ 7,111	$ 5,839	$ 4,567	$ 3,295	$ 2,023
9	Tax Depreciation Rate							
10	Tax Depreciation Amount							
11	Book - Tax Depreciation Difference	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272
12	Cumulative Difference	$ (9,019)	$ (7,747)	$ (6,475)	$ (5,203)	$ (3,931)	$ (2,659)	$ (1,388)
13	Accumulated Deferred Income Taxes (ADIT)	$ (2,592)	$ (2,227)	$ (1,861)	$ (1,495)	$ (1,130)	$ (764)	$ (399)
14	Average ADIT	$ (2,775)	$ (2,409)	$ (2,044)	$ (1,678)	$ (1,313)	$ (947)	$ (582)
15	Rate Base	$ 6,880	$ 5,973	$ 5,067	$ 4,161	$ 3,254	$ 2,348	$ 1,442
16	Return Requirement @ Pre-tax cost of capital	$ 621	$ 539	$ 458	$ 376	$ 294	$ 212	$ 130
17	Distribution Costs:							
18	Economic Development Net Donations							
	Societal Perspective - Net Benefit (Envrio Damage Costs - externalities)	$ 28,549	$ 29,574	$ 30,635	$ 31,735	$ 32,874	$ 34,055	$ 35,277
19	System Operating and Maintence Costs	$ 2,117	$ 2,193	$ 2,272	$ 2,353	$ 2,438	$ 2,525	$ 2,616
20	Depreciation Expense	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272	$ 1,272
21	Property Taxes	$ 1,252	$ 1,297	$ 1,344	$ 1,392	$ 1,442	$ 1,494	$ 1,548
22	Total Revenue Requirement	$ 33,811	$ 34,875	$ 35,981	$ 37,128	$ 38,320	$ 39,558	$ 40,843
23	Customer Non-Energy Revenues at proposed rates	$ 146,461	$ 146,461	$ 146,461	$ 146,461	$ 146,461	$ 146,461	$ 146,461
24	Revenue Excess (Deficiency)	$ 112,650	$ 111,586	$ 110,480	$ 109,333	$ 108,141	$ 106,903	$ 105,618
25	NPV of annual revenue excess (deficiency) @ Overall Return	$ 25,012	$ 23,137	$ 21,394	$ 19,772	$ 18,263	$ 16,860	$ 15,556
26	Cumulative NPV	$ 1,293,120	$ 1,316,258	$ 1,337,651	$ 1,357,423	$ 1,375,686	$ 1,392,546	$ 1,408,102

Economic Development - Commercial - with Societal Perspective

Net Present Value of Cash Flows

Line No.		Extension Year No. 29	Extension Year No. 30	Extension Year No. 31	Extension Year No. 32
	REVENUE REQUIREMENTS ANALYSIS:				
1	Total Cost				
2					
3					
4	Total cost:				
5	Beginning Balance				
6	Depreciation Expense (including negative salvage)	$ 1,272	$ 1,272	$ 1,272	$ 1,272
7	Ending Balance - Net Plant	$ 116	$ (1,156)	$ (2,428)	$ (3,700)
8	Average Net Plant	$ 752	$ (520)	$ (1,792)	$ (3,064)
9	Tax Depreciation Rate				
10	Tax Depreciation Amount				$ 3,700
11	Book - Tax Depreciation Difference	$ 1,272	$ 1,272	$ 1,272	$ (2,428)
12	Cumulative Difference	$ (116)	$ 1,156	$ 2,428	$ -
13	Accumulated Deferred Income Taxes (ADIT)	$ (33)	$ 332	$ 698	$ -
14	Average ADIT	$ (216)	$ 150	$ 515	$ 349
15	Rate Base	$ 536	$ (371)	$ (1,277)	$ (2,715)
16	Return Requirement @ Pre-tax cost of capital	$ 48	$ (33)	$ (115)	$ (245)
17	Distribution Costs:				
18	Economic Development Net Donations				
	Societal Perspective - Net Benefit (Envrio Damage Costs - externalities)	$ 36,544	$ 37,856	$ 39,215	$ 40,622
19	System Operating and Maintence Costs	$ 2,710	$ 2,807	$ 2,908	$ 3,012
20	Depreciation Expense	$ 1,272	$ 1,272	$ 1,272	$ 1,272
21	Property Taxes	$ 1,603	$ 1,661	$ 1,720	$ 1,782
22	Total Revenue Requirement	$ 42,177	$ 43,562	$ 44,999	$ 46,444
23	Customer Non-Energy Revenues at proposed rates	$ 146,461	$ 146,461	$ 146,461	$ 146,461
24	Revenue Excess (Deficiency)	$ 104,284	$ 102,899	$ 101,462	$ 100,017
25	NPV of annual revenue excess (deficiency) @ Overall Return	$ 14,344	$ 13,218	$ 12,171	$ 11,205
26	Cumulative NPV	$ 1,422,446	$ 1,435,664	$ 1,447,836	$ 1,459,041

Non-Asset Based Trading Cost Study

Introduction

Northern States Power Company, doing business as Xcel Energy (Xcel Energy, NSPM, or the Company) agreed in its 2011 test year general electric rate case (Docket No. E002/GR-10-971 or 2010 Rate Case) to two items regarding non-asset based trading:

> "The Company has agreed to submit an incremental and fully-allocated cost study of non-asset-based trading with its next rate case;"[1] and
>
> "…would remove non-asset based margins and their associated embedded costs from the revenue requirement…"[2]

In the Company's last rate case (Docket No. E002/GR-15-826), the Company requested that it only be required to submit a fully allocated cost study because the incremental cost study is not used to determine the level of costs to charge to this activity. That request was not opposed. Consequently, this report summarizes the cost study undertaken by the Company to determine the fully allocated cost of non-asset based trading activity.

Background

There are two main categories of short-term wholesale trading: asset based transactions and non-asset based transactions. Asset based transactions involve the sales of excess energy or capacity from Company-owned generation assets. Non-asset based transactions are undertaken as energy market opportunities to make revenues, and are unrelated to meeting the needs of the Native Load customers (retail customers and requirements wholesale customers taking service at cost-based rates).

Non-asset based trading transactions are those in which:

- Energy or capacity is purchased from a third party but is unrelated to serving native load
- That energy or capacity is resold for profit

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[1] Docket No. E002/GR-10-971 ALJ Report, Findings of Fact, February 22, 2012; ALJ Findings 278 and 315.
[2] Docket No. E002/GR-10-971 PUC Findings of Fact, Conclusions and Order, May 14, 2012; page 9.

The costs that are being examined in this study are related exclusively to non-asset based trading.

Prior to the 2010 Rate Case, the Company shared non-asset based margins with customers. In its 2009 test year general electric rate case (Docket No. E002/GR-08-1065 or 2008 Rate Case), the Company committed to perform both an incremental and fully distributed cost study of non-asset based trading activities as part of its next general electric rate case application. Therefore, the 2010 Rate Case included the first such study.

In the settlement of the 2010 Rate Case proceedings, the Company agreed to change the ratemaking treatment of non-asset based trading margins: the fully allocated cost of non-asset based trading activity is now excluded from the Company's revenue requirements, and the non-asset based trading margins are retained by the Company. Further, as noted above the Company's proposal to provide solely a fully allocated cost study in this case was not opposed in the Company's most recent past rate case. This study therefore provides support for the fully allocated cost adjustment made for the 2020 test year and 2021-2022 plan years.

Fully Allocated Cost Analysis

The Company defines fully allocated costs as the incremental costs along with a reasonable contribution of common overhead costs. There are two components of fully allocated costs – 1) expenses and 2) a share of capital costs. All expenses recorded as non-asset based trading are considered fully distributed costs (i.e., an allocation percentage has not been applied to non-productive labor costs – for example labor loadings such as pension and insurance – as was done in the incremental cost study). In addition, Information Technology (IT) systems costs that are necessary to support these activities are included in the fully allocated costs. In total, the fully allocated O&M costs include the following components: Labor, indirect labor overheads (which includes rents), and IT system costs.

Labor

The labor itself is directly recorded as being non-asset based trading. However, the Company has also included labor overhead allocations (for example pension and insurance) to the directly assigned labor in the fully allocated section of the study.

Labor Overhead

In addition to the labor overhead costs identified in the labor section above, a labor overhead rate of 14.69 percent was also applied to non-asset based trading labor. This is the same rate applied to total labor and labor loadings for charges to the non-regulated businesses within NSPM and for third party billings.

Attachment A shows the fully allocated labor and overhead costs associated with non-asset based trading for 2016-2018 actuals and 2020-2022 MYRP forecast.

IT Systems

In addition to the labor and labor overhead expenses, the Company identified IT systems used to facilitate non-asset based trading. The table below summarizes the computer systems identified which support non-asset based trading activities:

System	Description
ACES	No test year expenses
Business Objects (BO)	Query tool
Commodity XL	Manage commodity trading logistics and risk management
CXT	Customer Experience Transformation
Documentum	Storage of contract documentation – no test year expenses
JDE	General ledger system used to account for trade activity for financial reporting – no test year expenses
PCI MISO	Bid-to-bill transaction management tool used for MISO activity – no test year expenses
SAP GL	New general ledger system used by Company
WAM	Work and Asset Management system connects field employees with data in SAP

IT System O&M Expense – An analysis was conducted to determine the amount of IT System O&M expense that is related to non-asset based trading. First, for each IT system listed above, the amount of O&M expense assigned to NSPM was identified. Then the portion of the NSPM IT system O&M expense allocated to non-asset based trading was calculated based upon the Non-Asset Revenue Percent (a ratio of NSPM non-asset based trading revenue to NSPM Electric Utility revenue). Please see the top half of Attachment B for the IT system O&M expense assigned to non-asset based trading 2018 actual and the 2020-2022 MYRP forecast.

IT System Capital Revenue Requirements – An analysis was also conducted to determine the IT system capital revenue requirements associated with non-asset based trading. First, the rate base associated with the above listed IT systems was determined and the total 2020-2022 budget rate base and depreciation expense (capital costs) for the above listed IT systems was calculated. Second, the Non-Asset Revenue Percent was applied to the capital costs to calculate the IT system capital costs attributable to non-asset based trading. (See the bottom half of Attachment B.) Third, the resulting rate base and depreciation expense was used to calculate the 2020 test year and 2021-2022 plan years revenue requirements related to non-asset based trading. Attachment C shows the 2020-2022 IT systems capital revenue requirement calculation.

Conclusion

As shown in Attachment D, using the above described assumptions and methodology, each of the 2020 test year and 2021-2022 plan years includes approximately $1.8 million in annual fully allocated costs attributed to non-asset based trading activity associated with the State of Minnesota electric retail jurisdiction.

Northern States Power Company
Summary of Non-Asset Based Trading Costs

Attachment A

Fully Allocated Costs

O&M Expenses	**2016**	**2017**	**2018**	**Three Year Avg (2016-2018)**	**2019 YE Forecast**	**2020 Test Year**	**2021 Plan Year**	**2022 Plan Year**
Trading	$ 1,416,654	$ 1,340,704	$ 772,826	$ 1,176,728	$ 906,186	$ 937,836	$ 961,770	$ 986,374
Trading - SIP	$ 251,076	$ 714,408	$ 854,215	$ 606,566	$ 899,492	$ 732,818	$ 869,701	$ 843,537
Risk	$ 292,809	$ 798,634	$ 271,989	$ 454,478	$ 442,310	$ 377,079	$ 398,052	$ 410,309
Accounting	$ 36,483	$ 226,820	$ 68,290	$ 110,531	$ 74,634	$ 10,601	$ 10,919	$ 11,247
Indirect Labor Overhead	$ 625,354	$ 940,845	$ 527,519	$ 697,906	$ 484,141	$ 547,167	$ 556,910	$ 559,406
	$ 2,622,376	$ 4,021,411	$ 2,494,839	$ 3,046,209	$ 2,806,762	$ 2,605,501	$ 2,797,353	$ 2,810,873
Less Trading - SIP	$ (251,076)	$ (714,408)	$ (854,215)	$ (606,566)	$ (899,492)	$ (732,818)	$ (869,701)	$ (843,537)
Total Fully Allocated O&M Expenses	**$ 2,371,300**	**$ 3,307,003**	**$ 1,640,624**	$ 2,439,643	**$ 1,907,270**	**$ 1,872,684**	**$ 1,927,652**	**$ 1,967,336**

System Costs Related to Non-Asset Trading

Attachment B

	2018 Actual	2019	2020	2021	2022
Total Operating Revenues	4,641,645,997	4,548,117,187	4,499,847,478	4,530,039,652	4,546,378,992
NSPM Non-Asset Based Trading Revenue	37,194,992	29,999,988	35,999,986	35,999,986	35,999,986
Non-Asset Trading as Percent of Total	0.80%	0.66%	0.80%	0.79%	0.79%

Actual and Fcst Depr Expense Year

Row Labels	2018 Actual	Sum of Est 2019	Sum of Est 2020	Sum of Est 2021	Sum of Est 2022
ACES	0	0	0	0	0
BO	188,673	134,936	0	0	0
CXT	1,170,497	1,063,875	1,063,875	971,862	615,027
Documentum	137,051	44,594	0	0	0
JDE	0	0	0	0	0
PCI MISO	69,416	0	0	0	0
SAP GL	2,011,384	2,016,874	2,016,874	2,016,874	2,016,874
WAM	7,787,935	7,877,830	7,877,830	7,877,830	7,877,830
SAP	234,505	500,062	500,062	460,900	305,072
COMMODITY XL	0	76,979	76,979	76,979	76,979
Grand Total	**11,599,461**	**11,715,150**	**11,535,620**	**11,404,445**	**10,891,783**
IT Dep'n related to Non-Asset trading		92,950	84,278	97,947	96,949

Depr Reserves and Net Book Values by Year

Row Labels		Sum of 2019 Depr Reserve	Sum of 2020 Depr Reserve	Sum of 2021 Depr Reserve	Sum of 2022 Depr Reserve
ACES		507,695.91	507,695.91	507,695.91	507,695.91
BO		882,570.60	882,570.60	882,570.60	882,570.60
CXT		6,981,595.62	8,045,470.86	9,017,333.06	9,632,360.33
Documentum		2,520,332.21	2,520,332.21	2,520,332.21	2,520,332.21
JDE		0.00	0.00	0.00	0.00
PCI MISO		1,616,480.08	1,616,480.08	1,616,480.08	1,616,480.08
SAP GL		8,187,221.96	10,204,095.68	12,220,969.40	14,237,843.12
WAM		21,155,844.74	29,033,674.69	36,911,504.64	44,789,334.59
SAP		883,777.31	1,383,838.91	1,844,738.52	2,149,810.86
COMMODITY XL		76,979.41	153,958.82	230,938.23	307,917.64
Grand Total		**42,812,497.85**	**54,348,117.77**	**65,752,562.66**	**76,644,345.35**
Undepreciated Balances related to Non-Asset trading		340,229	431,902	522,532	609,089

Northern States Power Company, a Minnesota corporation **Attachment C**

Non-Asset Based Trading Study Revenue Requirement

Total NSPM

Rate Analysis	**2019**	**2020**	**2021**	**2022**
Rate Base				
EOY Net Plant	1,004,411	750,686	819,248	727,232
Depreciation	92,950	84,278	97,947	96,949
BOY Net Plant	1,097,361	834,964	917,195	824,180
Average Rate Base	**1,050,886**	**792,825**	**868,222**	**775,706**
Revenue Requirements				
Debt Return	21,900	16,500	18,100	16,100
Equity Return	56,300	42,500	46,500	41,600
Current Income Tax Requirement	22,700	17,100	18,800	16,800
Book Depreciation	92,950	84,278	97,947	96,949
Annual Deferred Tax	-	-	-	-
ITC Flow Thru	-	-	-	-
Tax Depreciation & Removal Expense	92,950	84,278	97,947	96,949
AFUDC Expenditure	-	-	-	-
Book Depreciation Cleared to Operating	-	-	-	-
Avoided Tax Interest	-	-	-	-
Property Tax	-	-	-	-
Total NSPM Revenue Requirements	**193,850**	**160,378**	**181,347**	**171,449**
MN Jurisdictional Demand Allocator	86.9990%	86.9990%	86.9990%	86.9990%
Minnesota Jurisdiction Revenue Requi	**168,648**	**139,527**	**157,770**	**149,159**

Cap structure Proposed in Current rate case

Capital Structure	**Rate**	**Ratio**	**Weighted Cost**
Long Term Debt	**4.4000%**	**47.1200%**	**2.0700%**
Short Term Debt	**3.8100%**	**0.3800%**	**0.0100%**
Preferred Stock	**0.0000%**	**0.0000%**	**0.0000%**
Common Equity	**10.2000%**	**52.5000%**	**5.3600%**
Required Rate of Return			**7.4400%**
Tax Rate (MN)	28.7420%		

Northern States Power Company

Attachment D

Non-Asset Trading Fully Allocated O&M Costs

	Total NSPM Electric			
	2019F	**2020TY**	**2021PY**	**2022PY**
O&M from cost study				
Allocation Method	EEnergy			
Fully Allocated O&M Expenses	1,640,624	1,907,270	1,872,684	1,927,652
Associated IT costs				
Allocation Method	EDemand			
IT O&M costs	92,950	84,278	97,947	96,949
Revenue requirement on IT in rate base	~~100,900~~	~~76,100~~	~~83,400~~	~~74,500~~
Total associated IT costs	193,850	160,378	181,347	171,449
Total NSPM Costs	**1,834,475**	**2,067,648**	**2,054,030**	**2,099,100**

	Minnesota Electric Jurisdiction			
	2019F	**2020TY**	**2021PY**	**2022PY**
O&M from cost study				
Allocation Method	EEnergy			
Fully Allocated O&M Expenses	1,422,356	1,653,527	1,623,542	1,671,197
Associated IT costs				
Allocation Method	EDemand			
IT O&M costs	80,964	73,321	85,213	84,344
Revenue requirement on IT in rate base	~~87,888~~	~~66,206~~	~~72,557~~	~~64,814~~
Total associated IT costs	168,852	139,527	157,770	149,159
MN Electric Jurisdiction Adjustment	**1,591,207**	**1,793,054**	**1,781,312**	**1,820,356**

Production Tax Credits (PTCs)

2020-2022 MYRP
($000s)

MWH	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Annual - 2020
Grand Meadow													-
Nobles	71,491	60,620	66,611	70,415	61,261	49,080	36,826	29,613	48,666	67,405	69,610		631,598
Pleasant Valley	86,029	62,819	71,262	71,977	71,244	56,994	46,436	35,782	67,173	71,077	83,871	77,969	802,633
Boarder Winds	62,373	60,158	49,753	53,595	56,605	47,716	44,675	38,448	59,301	61,964	64,711	67,280	666,579
Courtenay	77,766	76,124	61,365	61,754	69,570	71,796	38,698	50,636	61,480	76,046	73,445	78,481	797,161
Blazing Star I	7,310	79,030	80,860	90,969	83,608	77,832	57,253	57,240	76,000	87,325	86,580	85,713	869,720
Foxtail	64,399	57,004	58,887	58,093	63,121	62,957	41,988	43,789	57,826	65,543	64,862	64,867	703,336
Lake Benton	43,820	38,124	42,090	44,020	39,138	36,540	32,204	26,914	35,788	41,628	41,092	40,502	461,860
Total	413,188	433,879	430,828	450,823	444,547	402,915	298,080	282,422	406,234	470,988	484,171	414,812	4,932,887
PTC Rate/Mwh	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
PTCs													
Grand Meadow	-	-	-	-	-	-	-	-	-	-	-	-	-
Nobles	1,787	1,516	1,665	1,760	1,532	1,227	921	740	1,217	1,685	1,740	-	15,790
Pleasant Valley	2,151	1,571	1,782	1,799	1,781	1,425	1,161	895	1,679	1,777	2,097	1,949	20,066
Boarder Winds	1,559	1,504	1,244	1,340	1,415	1,193	1,117	961	1,483	1,549	1,618	1,682	16,665
Courtenay	1,944	1,903	1,534	1,544	1,739	1,795	968	1,266	1,537	1,901	1,836	1,962	19,929
Blazing Star I	183	1,976	2,022	2,274	2,090	1,946	1,431	1,431	1,900	2,183	2,165	2,143	21,743
Foxtail	1,610	1,425	1,472	1,452	1,578	1,574	1,050	1,095	1,446	1,639	1,622	1,622	17,584
Lake Benton	1,096	953	1,052	1,101	979	914	805	673	895	1,041	1,027	1,013	11,547
Total	$ 10,330	$ 10,847	$ 10,771	$ 11,271	$ 11,114	$ 10,073	$ 7,452	$ 7,061	$ 10,156	$ 11,775	$ 12,104	$ 10,370	$ 123,323

State of MN Energy Allocator	86.6960%
State of MN PTCs	**$ 106,916**
Revenue Requirement Conversion Factor	1.40335
State of MN Revenue Requirements	**$ (150,041)**
Interchange Agreement Energy Allocation	17.0442%
Interchange Agreement Revenue Offset	$ (25,573)
State of MN Revenue Requirements (Net of IA)	**$ (124,467)**

Production Tax Credits (PTCs)

2020-2022 MYRP
($000s)

MWH	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Annual - 2021
Grand Meadow													-
Nobles													-
Pleasant Valley	86,029	62,025	71,262	71,977	71,244	56,994	46,436	35,782	67,173	71,077	83,871	77,969	801,839
Boarder Winds	62,373	58,628	49,753	53,595	56,132	47,716	44,675	38,448	59,301	61,964	64,711	67,280	664,576
Courtenay	77,766	74,816	61,365	61,754	69,116	71,796	38,698	50,636	61,480	76,046	73,445	78,481	795,399
Blazing Star I	83,629	77,599	80,860	90,969	83,608	77,832	57,253	57,240	76,000	87,325	86,580	85,713	944,608
Foxtail	64,349	56,286	58,887	58,093	61,205	62,183	41,988	43,789	57,192	65,110	62,600	64,230	695,912
Lake Benton	43,820	36,215	42,090	44,020	39,138	36,540	32,204	26,914	35,788	41,628	41,092	40,502	459,951
Total	417,966	365,569	364,217	380,408	380,443	353,061	261,254	252,809	356,934	403,150	412,299	414,175	4,362,285
PTC Rate/Mwh	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
PTCs													
Grand Meadow	-	-	-	-	-	-	-	-	-	-	-	-	-
Nobles	-	-	-	-	-	-	-	-	-	-	-	-	-
Pleasant Valley	2,151	1,551	1,782	1,799	1,781	1,425	1,161	895	1,679	1,777	2,097	1,949	20,046
Boarder Winds	1,559	1,466	1,244	1,340	1,403	1,193	1,117	961	1,483	1,549	1,618	1,682	16,614
Courtenay	1,944	1,870	1,534	1,544	1,728	1,795	968	1,266	1,537	1,901	1,836	1,962	19,885
Blazing Star I	2,091	1,940	2,022	2,274	2,090	1,946	1,431	1,431	1,900	2,183	2,165	2,143	23,615
Foxtail	1,609	1,407	1,472	1,452	1,530	1,555	1,050	1,095	1,430	1,628	1,565	1,606	17,398
Lake Benton	1,096	905	1,052	1,101	979	914	805	673	895	1,041	1,027	1,013	11,499
Total	$ 10,449	$ 9,139	$ 9,106	$ 9,510	$ 9,511	$ 8,827	$ 6,531	$ 6,320	$ 8,923	$ 10,079	$ 10,308	$ 10,354	$ 109,058

State of MN Energy Allocator	86.6960%
State of MN PTCs	**$ 94,548**
Revenue Requirement Conversion Factor	1.40335
State of MN Revenue Requirements	**$ (132,685)**
Interchange Agreement Energy Allocation	17.0442%
Interchange Agreement Revenue Offset	$ (22,615)
State of MN Revenue Requirements (Net of IA)	**$ (110,070)**

Production Tax Credits (PTCs)

2020-2022 MYRP
($000s)

MWH	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Annual - 2021
Grand Meadow													-
Nobles													-
Pleasant Valley	86029	62025	71262	71977	71244	56994	46436	35782	67173	71077	83871	77969	801,839
Boarder Winds	62373	58628	49753	53595	56144	47716	44675	38448	59301	61964	64711	67280	664,588
Courtenay	77766	74816	61365	61754	69229	71796	38698	50636	61480	76046	73445	78481	795,512
Blazing Star I	83629	77599	80860	90969	83608	77832	57253	57240	76000	87325	86580	85713	944,608
Foxtail	63783	55862	58371	55020	60911	61360	41988	43789	57335	65543	60762	64866	689,590
Lake Benton	43820	36215	42090	44020	39138	36540	32204	26914	35788	41628	41092	40502	459,951
Total	417,400	365,145	363,701	377,335	380,274	352,238	261,254	252,809	357,077	403,583	410,461	414,811	4,356,088
PTC Rate/Mwh	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
PTCs													
Grand Meadow	-	-	-	-	-	-	-	-	-	-	-	-	-
Nobles	-	-	-	-	-	-	-	-	-	-	-	-	-
Pleasant Valley	2,151	1,551	1,782	1,799	1,781	1,425	1,161	895	1,679	1,777	2,097	1,949	20,046
Boarder Winds	1,559	1,466	1,244	1,340	1,404	1,193	1,117	961	1,483	1,549	1,618	1,682	16,615
Courtenay	1,944	1,870	1,534	1,544	1,731	1,795	968	1,266	1,537	1,901	1,836	1,962	19,888
Blazing Star I	2,091	1,940	2,022	2,274	2,090	1,946	1,431	1,431	1,900	2,183	2,165	2,143	23,615
Foxtail	1,595	1,397	1,459	1,376	1,523	1,534	1,050	1,095	1,433	1,639	1,519	1,622	17,240
Lake Benton	1,096	905	1,052	1,101	979	914	805	673	895	1,041	1,027	1,013	11,499
Total	$ 10,435	$ 9,129	$ 9,093	$ 9,433	$ 9,507	$ 8,806	$ 6,531	$ 6,320	$ 8,927	$ 10,090	$ 10,262	$ 10,370	$ 108,903

State of MN Energy Allocator	86.6960%
State of MN PTCs	**$ 94,414**
Revenue Requirement Conversion Factor	1.40335
State of MN Revenue Requirements	**$ (132,496)**
Interchange Agreement Energy Allocation	17.0442%
Interchange Agreement Revenue Offset	$ (22,583)
State of MN Revenue Requirements (Net of IA)	**$ (109,913)**

IRS Pro-Rate Method Accumulated Deferred Tax Adjustment

Including NOL Annual Deferred at Last Authorized Rate of Return

Test Year Ending December 31, 2020

Pro-Rate Adjustment Factor

								2020	
Annual Deferred Tax Expense			19,761,733		0			19,761,733	
	Days to Prorate	Prorate Factor	MN Jurisdiction Prorated Plant Deferred	MN Jurisdiction Prorated Plant Deferred	MN Jurisdiction NOL	MN Jurisdiction Prorated NOL		Monthly Expense	Prorated Monthly Expense
January	335	91.78%	1,646,811	1,511,457	-	-		1,646,811	1,511,457
February	307	84.11%	1,646,811	1,385,126	-	-		1,646,811	1,385,126
March	276	75.62%	1,646,811	1,245,260	-	-		1,646,811	1,245,260
April	246	67.40%	1,646,811	1,109,906	-	-		1,646,811	1,109,906
May	215	58.90%	1,646,811	970,039	-	-		1,646,811	970,039
June	185	50.68%	1,646,811	834,685	-	-		1,646,811	834,685
July	154	42.19%	1,646,811	694,819	-	-		1,646,811	694,819
August	123	33.70%	1,646,811	554,953	-	-		1,646,811	554,953
September	93	25.48%	1,646,811	419,598	-	-		1,646,811	419,598
October	62	16.99%	1,646,811	279,732	-	-		1,646,811	279,732
November	32	8.77%	1,646,811	144,378	-	-		1,646,811	144,378
December	1	0.27%	1,646,811	4,512	-	-		1,646,811	4,512
								Total	**9,154,465**

	(Increase)/ decrease to accumulated deferred taxes
Increase/(Decrease) in Rate Base	
Pro-Rate Method	(9,154,465)
BOY/EOY Average	(9,880,867)
Accumulated Deferred Taxes Adjustment	726,402
ADIT Prorate for IRS Adjustment - Sch 10a	5,303,634
Adjustment	(4,577,232)

Capital Structure - Last Authorized	
Composite Tax Rate	28.74%
Weighted Cost of STD	0.07%
Weighted Cost of LTD	2.18%
Weighted Cost of Debt	2.25%
Weighted Cost of Equity	4.83%
Required Rate of Return	**7.08%**
Equity Return Tax RR	**1.95%**
RB Revenue Requirement Factor	9.0282%
Increase/(Decrease) in Revenue Requirement	
Annual Revenue Requirement Impact	65,581
ADIT Prorate for IRS Adjustment - Sch 11a	478,822
Adjustment	(413,241)

Capital Structure - Proposed	
Composite Tax Rate	28.74%
Weighted Cost of STD	0.03%
Weighted Cost of LTD	2.06%
Weighted Cost of Debt	2.09%
Weighted Cost of Equity	5.36%
Required Rate of Return	**7.45%**
Equity Return Tax RR	**2.16%**
RB Revenue Requirement Factor	9.6120%
Increase/(Decrease) in Revenue Requirement	
Annual Revenue Requirement Impact	69,821
ADIT Prorate for IRS Adjustment - Sch 12	509,783
Adjustment	(439,962)

			Pro-Rate Adjustment Factor				2021	
Annual Deferred Tax Expense			(1,404,329)		0		-1,404,329	
	Days to Prorate	Prorate Factor	MN Jurisdiction Prorated Plant Deferred	MN Jurisdiction Prorated Plant Deferred	MN Jurisdiction NOL	MN Jurisdiction Prorated NOL	Monthly Expense	Prorated Monthly Expense
January	335	91.78%	(117,027)	(107,409)	-	-	(117,027)	(107,409)
February	307	84.11%	(117,027)	(98,431)	-	-	(117,027)	(98,431)
March	276	75.62%	(117,027)	(88,492)	-	-	(117,027)	(88,492)
April	246	67.40%	(117,027)	(78,873)	-	-	(117,027)	(78,873)
May	215	58.90%	(117,027)	(68,934)	-	-	(117,027)	(68,934)
June	185	50.68%	(117,027)	(59,315)	-	-	(117,027)	(59,315)
July	154	42.19%	(117,027)	(49,376)	-	-	(117,027)	(49,376)
August	123	33.70%	(117,027)	(39,437)	-	-	(117,027)	(39,437)
September	93	25.48%	(117,027)	(29,818)	-	-	(117,027)	(29,818)
October	62	16.99%	(117,027)	(19,879)	-	-	(117,027)	(19,879)
November	32	8.77%	(117,027)	(10,260)	-	-	(117,027)	(10,260)
December	1	0.27%	(117,027)	(321)	-	-	(117,027)	(321)
							Total	**(650,544)**

Increase/(Decrease) in Rate Base	(Increase)/ decrease to accumulated deferred taxes
Pro-Rate Method	650,544
BOY/EOY Average	702,164
Accumulated Deferred Taxes Adjustment	(51,620)
ADIT Prorate for IRS Adjustment - Sch 10b	(376,892)
Adjustment	325,272

Capital Structure - Last Authorized	
Composite Tax Rate	28.74%
Weighted Cost of STD	0.07%
Weighted Cost of LTD	2.18%
Weighted Cost of Debt	2.25%
Weighted Cost of Equity	4.83%
Required Rate of Return	**7.08%**
Equity Return Tax RR	**1.95%**
RB Revenue Requirement Factor	9.0282%
Increase/(Decrease) in Revenue Requirement	
Annual Revenue Requirement Impact	(4,660)
ADIT Prorate for IRS Adjustment - Sch 11b	(34,027)
Adjustment	29,366

Capital Structure - Proposed	
Composite Tax Rate	28.74%
Weighted Cost of STD	0.03%
Weighted Cost of LTD	2.06%
Weighted Cost of Debt	2.09%
Weighted Cost of Equity	5.36%
Required Rate of Return	**7.45%**
Equity Return Tax RR	**2.16%**
RB Revenue Requirement Factor	9.6120%
Increase/(Decrease) in Revenue Requirement	
Annual Revenue Requirement Impact	(4,962)
ADIT Prorate for IRS Adjustment - Sch 12	(36,227)
Adjustment	31,265

			Pro-Rate Adjustment Factor				2022	
Annual Deferred Tax Expense			(32,518,219)		0		-32,518,219	
	Days to Prorate	Prorate Factor	MN Jurisdiction Prorated Plant Deferred	MN Jurisdiction Prorated Plant Deferred	MN Jurisdiction NOL	MN Jurisdiction Prorated NOL	Monthly Expense	Prorated Monthly Expense
January	335	91.78%	(2,709,852)	(2,487,124)	-	-	(2,709,852)	(2,487,124)
February	307	84.11%	(2,709,852)	(2,279,245)	-	-	(2,709,852)	(2,279,245)
March	276	75.62%	(2,709,852)	(2,049,093)	-	-	(2,709,852)	(2,049,093)
April	246	67.40%	(2,709,852)	(1,826,366)	-	-	(2,709,852)	(1,826,366)
May	215	58.90%	(2,709,852)	(1,596,214)	-	-	(2,709,852)	(1,596,214)
June	185	50.68%	(2,709,852)	(1,373,486)	-	-	(2,709,852)	(1,373,486)
July	154	42.19%	(2,709,852)	(1,143,335)	-	-	(2,709,852)	(1,143,335)
August	123	33.70%	(2,709,852)	(913,183)	-	-	(2,709,852)	(913,183)
September	93	25.48%	(2,709,852)	(690,455)	-	-	(2,709,852)	(690,455)
October	62	16.99%	(2,709,852)	(460,304)	-	-	(2,709,852)	(460,304)
November	32	8.77%	(2,709,852)	(237,576)	-	-	(2,709,852)	(237,576)
December	1	0.27%	(2,709,852)	(7,424)	-	-	(2,709,852)	(7,424)
							Total	**(15,063,805)**

	(Increase)/ decrease to accumulated deferred taxes
Increase/(Decrease) in Rate Base	
Pro-Rate Method	15,063,805
BOY/EOY Average	16,259,109
Accumulated Deferred Taxes Adjustment	(1,195,304)
ADIT Prorate for IRS Adjustment - Sch 10c	(8,727,207)
Adjustment	7,531,902

Capital Structure - Last Authorized	
Composite Tax Rate	28.74%
Weighted Cost of STD	0.07%
Weighted Cost of LTD	2.18%
Weighted Cost of Debt	2.25%
Weighted Cost of Equity	4.83%
Required Rate of Return	**7.08%**
Equity Return Tax RR	**1.95%**
RB Revenue Requirement Factor	9.0282%
Increase/(Decrease) in Revenue Requirement	
Annual Revenue Requirement Impact	(107,914)
ADIT Prorate for IRS Adjustment - Sch 11c	(787,908)
Adjustment	679,994

Capital Structure - Proposed	
Composite Tax Rate	28.74%
Weighted Cost of STD	0.03%
Weighted Cost of LTD	2.06%
Weighted Cost of Debt	2.09%
Weighted Cost of Equity	5.36%
Required Rate of Return	**7.45%**
Equity Return Tax RR	**2.16%**
RB Revenue Requirement Factor	9.6120%
Increase/(Decrease) in Revenue Requirement	
Annual Revenue Requirement Impact	(114,892)
ADIT Prorate for IRS Adjustment - Sch 12	(840,601)
Adjustment	725,709

Pro-Rate Adjustment Factor

Days	Month	Prorated Days	Prorate Factor
31	Jan	335	0.917808
28	Feb	307	0.841096
31	Mar	276	0.756164
30	Apr	246	0.673973
31	May	215	0.589041
30	Jun	185	0.506849
31	Jul	154	0.421918
31	Aug	123	0.336986
30	Sep	93	0.254795
31	Oct	62	0.169863
30	Nov	32	0.087671
31	Dec	1	0.002740
365			

Double Average Prorate Factor	0.231621
BOY/EOY Average Factor	0.500000
Prorate Adjustment Factor	0.268379

Removing Double Average from Prorate Factor

Average Prorate Factor	0.463242
BOY/EOY Average Factor	0.500000
Prorate Adjustment Factor	0.036758

Net Operating Loss (NOL)
Test Year Ending December 31, 2020
($000s)

Impact of Unused/(Utilized) Tax Deductions on Rate Base	2018 Annual Report EOY Balances	2019 Bridge Annual Utilization Amounts	2019 Bridge EOY Balances	2020 Test Year Annual Utilization Amounts	2020 Test Year EOY Balances	2021 Plan Year Annual Utilization Amounts	2021 Plan Year EOY Balances	2022 Plan Year Annual Utilization Amounts	2022 Plan Year EOY Balances
1. Unused/(Utilized) Deductions	0	0	0	0	0	0	0	0	0
2. Deferred Tax Effect of Unused/(Utilized) Deductions	0	0	0	0	0	0	0	0	0
3. Unused/(Utilized) Credits State	0	0	0	0	0	0	0	0	0
4. Unused/(Utilized) Credits Federal	300,550	9,326	309,876	93,712	403,587	172,039	575,626	157,543	733,168
5. Accumulated Deferred Income Taxes (ADIT)	**300,550**	**9,326**	**309,876**	**93,712**	**403,587**	**172,039**	**575,626**	**157,543**	**733,169**

Impact of Unused/(Utilized) Tax Deductions on Revenue Requirements	2019 Bridge Year Utilization Adjustment	2020 Test Year Utilization Adjustment	2021 Plan Year Utilization Adjustment	2022 Plan Year Utilization Adjustment	Comment
6. Deferred Tax Asset BOY	0	0	0	0	Zero since adjustment reflects current year utilization
7. Deferred Tax Asset EOY	9,326	93,712	172,039	157,543	From Utilization columns on Line 4
8. Average Rate Base	4,663	46,856	86,019	78,771	(BOY + EOY)/2
9. Return Requirement	348	3,491	6,408	5,884	Rate Base * Req Rate of Return
10. RR Tax on Equity Return	101	1,013	1,860	1,703	(T/(1-T))*RB*Equity Return
11. Rate Base Revenue Requirement	450	4,504	8,268	7,587	Line 9 + Line 10
12. Deferred Tax	(9,326)	(93,712)	(172,039)	(157,543)	From Utilization columns on Line 5
13. Current Tax Rev Req [1]	9,326	93,712	172,039	157,543	From Line 19
14. Total Annual Utilization Revenue Requirements	**450**	**4,504**	**8,268**	**7,587**	Line 10+11+12
[1] *Current Income Tax Rev Req Calculation*					
15. Utilized Deductions	-	-	-	-	Unused Annual Deductions
16. Deferred Taxes	(9,326)	(93,712)	(172,039)	(157,543)	Line 12
17. Unused State Tax Credits	-	-	-	-	From Utilization columns on Line 3
18. Unused Federal Tax Credits	9,326	93,712	172,039	157,543	From Utilization columns on Line 4
19. Current Income Tax Revenue Requirement	9,326	93,712	172,039	157,543	(T/(1-T))*(-Line 15+.79xLine16+Line17)+.79xLine 16+Line 17

Validation Section	2019	2020	2021	2022
Total Annual Utilization Revenue Requirements	450	4,504	8,268	7,587
RR on beg balance	28,985	29,785	38,793	55,444
Sec 199 Manufacture Production Deduction - Fed	-	-	-	-
Section 199 Revenue Requirement	-	-	-	-
Total NOL & Sec 199 for validation	29,435	34,289	47,061	63,031
RIS COSS	29,435	34,289	47,061	63,031
Difference	0	0	0	0
Total Average Rate Base	4,663	56,181	189,057	353,847

Weighted Cost of Capital	2019	2020	2021	2022
Active Rates and Ratios Version	Proposed	Proposed	Proposed	Proposed
Cost of Short Term Debt	2.71%	2.97%	2.99%	3.04%
Cost of Long Term Debt	4.48%	4.42%	4.44%	4.48%
Cost of Common Equity	10.20%	10.20%	10.20%	10.20%
Ratio of Short Term Debt	1.65%	0.87%	1.22%	1.08%
Ratio of Long Term Debt	45.46%	46.63%	46.28%	46.42%
Ratio of Common Equity	52.89%	52.50%	52.50%	52.50%
Weighted Cost of STD	0.04%	0.03%	0.04%	0.03%
Weighted Cost of LTD	2.04%	2.06%	2.05%	2.08%
Weighted Cost of Debt	2.08%	2.09%	2.09%	2.11%
Weighted Cost of Equity	5.39%	5.36%	5.36%	5.36%
Required Rate of Return	**7.47%**	**7.45%**	**7.45%**	**7.47%**

Corp Composite Tax Rate	28.11%	28.11%	28.11%	28.11%
MN Composite Tax Rate	28.74%	28.74%	28.74%	28.74%

MYRP Forecast Fuel Reconciliation

Category	2020 Test Year	2021 Plan Year	2022 Plan Year	Comments
Fuel and Purchased Power	$ 1,062,005	$ 1,062,360	$ 1,061,665	BCH-1, Sch. 11a-11c, column 6, row 10
Costs Not Recoverable in Fuel Clause:				
Less Fuel Handling O&M Expenses	$ (18,083)	$ (18,438)	$ (17,742)	
Less Non-Asset Based Trading Expenses	$ (6,918)	$ (6,918)	$ (6,918)	
Less Off-System Sales Net of Interchange	$ (103,457)	$ (103,457)	$ (103,457)	
Less Windsource Fuel Costs	$ (7,605)	$ (7,605)	$ (7,605)	
Less Renewable*Connect Costs	$ (6,395)	$ (6,395)	$ (6,395)	
Subtotal	$ (142,459)	$ (142,814)	$ (142,118)	
Interchange Agreement Impacts				
Less Minnesota Fuel Costs Offset by Interchange Revenue	$ (123,492)	$ (123,492)	$ (123,492)	
Total Minnesota Fuel Costs included in Cost of Service	$ 796,055	$ 796,055	$ 796,055	
Minnesota Fuel Costs recovered through FCA	$ 796,055	$ 796,055	$ 796,055	FCA revenues included in retail revenue
Difference in Fuel Costs and Fuel Revenue	$ -	$ -	$ -	

Rider Roll-In Timeline****

		2020 Test Year	2021 Rate Plan Year	2022 Rate Plan Year
TCR Rate Rider				
CapX2020 Brookings*	Base Rates	X	X	X
CapX2020 Fargo*	Base Rates	X	X	X
CapX2020 La Crosse*	Base Rates	X	X	X
Big Stone - Brookings*	Base Rates	X	X	X
La Crosse - Madison*	Base Rates	X	X	X
MISO RECB Sch 26 and 26A net revenues**	TCR Rider Projects	✓	✓	✓
ADMS**	TCR Rider Projects	✓	✓	✓
Huntley Wilmarth**	TCR Rider Projects	✓	✓	✓
Interim rates - No TCR Projects in 2020/2021				
RES Rate Rider				
Courtenay Wind Farm*	Base Rates	X	X	X
Foxtail Wind Farm*	Base Rates	X	X	X
Blazing Star I Wind Farm*	Base Rates	X	X	X
Lake Benton Wind Farm*	Base Rates	X	X	X
Blazing Star II Wind Farm**	RES Rate Rider	✓	✓	✓
Freeborn Wind Farm**	RES Rate Rider	✓	✓	✓
Crowned Ridge Wind Farm**	RES Rate Rider	✓	✓	✓
Dakota Range Wind Farm**	RES Rate Rider	✓	✓	✓
Interim rates - No RES Projects in 2020/2021				

* Included in 2020 to 2022 Plan Years with 2020 and 2021 Interim rate adjustments to exclude from Interim rates; to be recovered in base rates and removed from the TCR Rider at conclusion of the case.

** Removed from 2020 to 2022 Plan Year revenue requirement calculations (revenues and expenses), projects continue recovery in the RES and TCR Riders. after the conclusion of the rate case.

**** The Rider Roll-In Timeline is based on the Compliance Activities identified in the Direct Testimony of Mr. Halama

Procedural Key Milestones from Nov 2019 to June 2021 (tentative subject to change based on procedural schedule)

- November 1, 2019: 2020 Rate Case filed
- Week of October 28, 2019: 2019-2020 RES/TCR Rider Supplements filed
- January 1, 2020: 2020 Interim Rates and 2020 RES/TCR rate effective
- January 1, 2021: 2021 Interim Rates
- March 1st, 2021: MPUC Multi-Year Rate Plan Order
- April 1, 2021: Final Rates Compliance Filing