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-21-630 Exhibit___(BCH-1)

2022 Test Year and 2023-2024 Plan Years
Overall Revenue Requirements
Rate Base
Income Statement
Rate Rider Recovery 2022-2024

October 25, 2021

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1		I. INTRODUCTION
2		
3	Q.	PLEASE STATE YOUR NAME AND TITLE.
4	Α.	My name is Benjamin C. Halama. I am the Manager of Revenue Analysis for
5		Xcel Energy Services Inc. (XES or the Service Company), the service company
6		for Xcel Energy, Inc. and its operating company subsidiaries.
7		
8	Q.	PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.
9	Α.	I have more than six years of experience at XES, supporting Northern States
10		Power Company–Minnesota (NSPM or the Company) in the areas of regulatory
11		accounting, financial operations, and revenue requirements. In my current role,
12		I am responsible for the development of jurisdictional revenue requirements for
13		all NSPM jurisdictions. My resume is attached as Exhibit(BCH-1), Schedule
14		1, Resume.
15		
16	Q.	WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?
17	Α.	In my Direct Testimony, I support the Company's Minnesota jurisdiction
18		electric operations cost of service, revenue requirements, and revenue
19		deficiency for each of the three years of the Company's multi-year rate plan
20		(MYRP), which include calendar year 2022 (the test year) and 2023 and 2024
21		(the plan years). Overall, the net deficiencies and retail revenue requirements
22		for the test year and plan years are summarized in Table 1 below:

Table 1 1 2022-2024 Revenue Requests 2 Minnesota Jurisdictional Deficiency Net of Interchange (\$s in millions) 3 **MYRP** Year 2022 2023 2024 4 Amount, cumulative \$396.0 \$546.1 \$677.3 5 Amount, incremental \$396.0 \$150.2 \$131.2 6 Average % increase, 12.2% 4.8% 4.2% incremental * * The "average percent increase, incremental" is calculated using the annual 8 revenue request over the forecasted present revenues in each applicable year, less prior year(s). 9 10 I provide the financial data supporting these overall revenue deficiencies for the 11 State of Minnesota retail electric jurisdiction, including a description of cost 12 changes, the data we provide, and our selection of the test year. Further, I 13 present: 14 • our jurisdictional cost of service study and the revenue requirement 15 effects of our utility and jurisdictional allocations; and 16 our revenue requirement, including rate base and income statement 17 components, with related adjustments and amortizations. 18 19 My testimony also supports the 2022 and 2023 requested interim rate increases 20 discussed in the Company's Petition for Interim Rates. Company witness Mr. 21 Gregory P. Chamberlain provides additional support for the interim rate 22 increases proposed as a part of our MYRP, as does the Notice and Petition for

Interim Rates, included in Volume 1 of our Application.

23

1		In addition, I explain our treatment of riders, and identify certain compliance
2		requirements addressed in our general rate filing.
3		
4		I relied on information provided by other Company witnesses in this proceeding
5		to develop many of the test year revenue requirement adjustments discussed in
6		my Direct Testimony.
7		
8	Q.	How is the rest of your Direct Testimony organized?
9	Α.	I present my testimony in the following sections:
10		• Section II, Case Overview, summarizes our jurisdictional revenue
11		requirement for the 2022 test year and 2023-2024 plan years, and
12		discusses the key drivers of cost increases compared to our last MYRP
13		established in Docket No. E002/GR-15-826 (the 2016-2019 MYRP).
14		• Section III, Supporting Information, provides information related to the data
15		provided in our application, the selection of the test year and plan years,
16		and the jurisdictional cost of service study.
17		• Section IV, Rate Base, identifies and explains the components of rate base,
18		and supports the reasonableness of the Company's projected 2022 test
19		year and 2023-2024 plan years rate base.
20		• Section V, Income Statement, identifies and explains the major components
21		of the income statement and supports the reasonableness of the
22		Company's proposed 2022 test year and 2023-2024 plan years income
23		statement.
24		• Section VI, Utility and Jurisdictional Allocations, explains why it is necessary
25		for the Company to allocate costs among its affiliates and between
26		jurisdictions, and describes the utility and jurisdictional allocators that are

1		used in determining the MYRP revenue requirement.
2		• Section VII, Annual Adjustments to the MYRP, presents adjustments
3		affecting the 2022 test year and 2023-2024 plan years revenue
4		requirements, providing both rate base and income statement impacts.
5		• Section VIII, Costs Recovered in Riders, presents our proposed treatment of
6		costs recovered in riders during the MYRP period, providing details
7		about which riders we propose to continue to use and costs we propose
8		to move into base rates, coincident with the implementation of fina
9		rates.
10		• Section IX, Compliance with Prior Commission Orders, provides information
11		related to specific requirements from prior Minnesota Public Utilities
12		Commission (Commission) Orders that have not been addressed
13		elsewhere in my testimony.
14		• Section X, Conclusion, summarizes our request.
15		
16	Q.	Are all the dollar values presented in your testimony
17		JURISDICTIONALIZED TO STATE OF MINNESOTA ELECTRIC JURISDICTION?
18	Α.	While most of the dollar values presented in my testimony are jurisdictionalized
19		to State of Minnesota Electric Jurisdiction, there are several instances where
20		dollars are either Total Company, or net of Interchange Agreement (IA) billings
21		to Northern States Power Company-Wisconsin (NSPW). Dollar values that are
22		Total Company or net of Interchange Agreement billings to NSPW are labeled
23		accordingly.

1	Q.	DO YOU PROVIDE INFORMATION IN COMPLIANCE WITH PAST COMMISSION
2		ORDERS AND COMPANY COMMITMENTS?
3	Α.	Yes. Throughout my testimony, I note where I am providing information
4		related to prior Commission Orders and Company commitments. In Section
5		IX, I provide additional information related to compliance with prior
6		Commission Orders that have not been addressed elsewhere in my testimony.
7		
8		II. CASE OVERVIEW
9		
10	Q.	WHAT TOPICS DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?
11	Α.	In this section, I will:
12		• present the jurisdictional revenue requirement and revenue deficiencies
13		for Minnesota for the 2022 test year and 2023-2024 plan years, referred
14		to in total as the "MYRP Forecast;"
15		• present a summary comparison of the costs in the MYRP Forecast to the
16		costs in the 2016-2019 MYRP approved in our last completed rate case,
17		which include costs and changes and true-ups in each year of the MYRP;
18		and
19		• provide an explanation of the primary sources of the changes in overall
20		costs, including plant-related costs and operations and maintenance
21		(O&M) costs.
22		
23		A. MYRP Jurisdictional Revenue Requirements and Deficiencies
24	Q.	PLEASE DESCRIBE THE BASIS OF THE COMPANY'S MYRP PROPOSAL.
25	Α.	The Company's three-year plan utilizes 2022 as the test year, with 2023 and 2024
26		as additional plan years developed using budgeted capital additions and

1		budgeted O&M expenses. Also included in the proposal are impacts to other
2		rate base items, sales adjustments, and other adjustments impacting the revenue
3		requirements for these years, so that each year represents a cost of service
4		approach to rate-setting for both capital and O&M.
5		
6	Q.	What is the 2022 test year jurisdictional overall revenue
7		REQUIREMENT AND REVENUE DEFICIENCY?
8	Α.	The overall jurisdictional revenue requirement for the 2022 test year is \$3.65
9		billion. The 2022 test year revenue deficiency, excluding rider roll-ins, is \$396.0
10		million. The 2022 test year revenue deficiency amount represents a 12.2 percent
11		overall increase in retail revenues from base rates compared to projected 2022
12		retail revenues at present rates. A summary of the 2022 revenue deficiency (in
13		dollars and as a percent) is provided in Exhibit(BCH-1) Schedule 2,
14		Summary of Revenue Requirements. The calculation of these dollar amounts
15		is provided in Exhibit(BCH-1) Schedule 3, Cost of Service Study Summary.
16		
17	Q.	WHAT ARE THE OVERALL REVENUE REQUIREMENT AND REVENUE
18		DEFICIENCIES FOR THE 2023 THROUGH 2024 PLAN YEARS?
19	A.	The overall jurisdictional revenue requirements for the 2023 and 2024 plan
20		years are \$3.76 billion and \$3.87 billion, respectively. The 2023 and 2024
21		revenue deficiencies, excluding rider roll-ins, are \$546.1 million and \$677.3
22		million, respectively. The overall revenue requirement request for the MYRP
23		Forecast represents a 21.2 percent increase in retail revenues from base rates in
24		2024 compared to projected 2024 retail revenues at present rates. A summary
25		of the 2023 and 2024 revenue deficiencies (in dollars and as percentages) is
26		provided in Schedule 2, Summary of Revenue Requirements. The calculation

1		of these dollar amounts is provided in Schedule 3, Cost of Service Study
2		Summary.
3		
4	Q.	What is the amount of the interim rate revenue deficiency in 2022?
5	Α.	The Interim Rate Petition (Petition) supports an interim revenue deficiency
6		based on the 2022 test year of \$288.3 million, which results in a proposed
7		interim rate increase of 9.4 percent beginning January 1, 2022.
8		
9	Q.	Is an interim rate request for 2023 included in this filing?
10	Α.	Yes. As discussed in the Direct Testimony of Mr. Chamberlain and in the
11		Notice and Petition for Interim Rates, the Company is also proposing an interim
12		rate adjustment for 2023 as part of its multi-year rate plan filing. The 2023
13		interim rate revenue deficiency includes an additional \$135.1 million beginning
14		on January 1, 2023, which equates to an additional interim rate increase of 4.5
15		percent in 2023.
16		
17	Q.	How does the Company calculate its revenue requirement and
18		REVENUE DEFICIENCY?
19	Α.	The general formula for calculation of the revenue requirement and revenue
20		deficiency is depicted below in Table 2:

1			Tab	le 2		
2		Revenue Requ	irement a	nd Reveni	ue Deficie	ncy
3			2022	2023	2024	Exhibit (BCH-1),
4			Test Year	Plan Year	Plan Year	, ,,
5			Amount	Amount	Amount	Sch. 3
		Item	(\$000s)	(\$000s)	(\$000s)	Reference
6		Average Rate Base	\$10,931,371	\$11,445,687	\$11,918,156	Page 1, Line 44
7	multiplied by	Cost of capital	7.31%	7.28%	7.30%	Page 1, Line 20
8		Operating Income Requirement	\$799,083	\$833,246	\$870,025	Page 4, Line 158
9						D 0.11 47 47
10		Current Retail Revenue	\$3,256,313	\$3,214,831	\$3,191,440	Page 2, Line 47 + Line 48
	plus	Current Other Revenue	\$595,815	\$609,232	\$620,259	Page 2, Line 49
11	equals	Current Total Revenue	\$3,852,129	\$3,824,063	\$3,811,699	Page 2, Line 50
12	minus	Operating Expenses	\$2,427,130	\$2,469,029	\$2,487,435	Page 2, Line 74
1.2	minus	Depreciation Expense	\$815,505	\$849,115	\$899,980	Page 2, Line 76
13	minus	Amortization Expense	\$61,229	\$55,267	\$54,647	Page 2, Line 77
14	minus	Taxes	\$64,555	\$38,329	\$20,812	Page 3, Line 135
15	plus	AFUDC	\$33,212	\$31,766	\$38,536	Page 4, Line 140 + Line 141
16	equals	Total Available for Return	\$516,922	\$444,090	\$387,362	Page 4, Line 143
17		Operating Income Requirement	\$799,083	\$833,246	\$870,025	Page 4, Line 158
	minus	Total Available for Return	\$516,922	\$444,090	\$387,362	Page 4, Line 143
18	equals	Income Deficiency	\$282,161	\$389,156	\$482,664	Page 4, Line 160
19	multiplied by	Gross Revenue Conversion Factor	1.403351	1.403351	1.403351	Page 4, Line 162
20	equals	Revenue Deficiency	\$395,971.58	\$546,122.96	\$677,346.77	Page 4, Line 163
21	plus	Current Retail Revenue	\$3,256,313	\$3,214,831	\$3,191,440	Page 4, Line 166
22	equals	Total Revenue Requirement	\$3,652,285	\$3,760,954	\$3,868,787	Page 4, Line 168

Q. HAS THE COMPANY PROVIDED AN EXPLANATION OF THE ASSUMPTIONS AND

1

2		APPROACHES USED IN DEVELOPING THE TEST YEAR OPERATING INCOME?
3	Α.	Yes. An explanation is provided in the Financial Information section of
4		Volume 3 (Required Information) of this Application. In addition, workpapers
5		supporting the 2022 test year cost of service are provided in Volume 4 (MYRP
6		Workpapers) of this Application.
7		
8	Q.	How does the Company treat capital and O&M costs in the 2022-2024
9		MYRP?
10	Α.	Our proposal uses the following reasoning to develop costs:
11		1. Capital, capital-related, and O&M costs follow the Company's budget,
12		except as needed to comply with prior Commission Orders or
13		adjustments the Company is specifically proposing in this proceeding.
14		(Capital-related consists of depreciation and allowance for funds used
15		during construction (AFUDC) as well as the cost of capital).
16		2. Fuel revenues and expenses for all years of the 2022-2024 MYRP are
17		represented in this docket based on the level filed in the Company's July
18		30, 2021 fuel update ¹ as discussed in the Company's August 11, 2019
19		Compliance Filing approved by the Commission in Docket No.
20		E999/CI-03-802. ²
21		3. Expenses that have jurisdiction-specific regulatory accounting treatment
22		follow that treatment. For example:

¹ Company's July 31, 2021, Reply Comments, Docket No. E002/AA-21-295.

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² Fuel expenses for the 2022-2024 MYRP are held flat at the filed level, but the Fuel and Purchased Energy line of the cost of service model (BCH-1 Schedule 3, row 58) fluctuates due to inclusion of fuel handling base O&M and the Benson PPA).

1		a. The Company amortizes nuclear fueling outage costs over the periods
2		between outages. These costs should follow the Company's budget;
3		and
4		b. Expenses related to the Company's pension and benefit costs have
5		several regulatory adjustments based on the outcome of the
6		Company's recent rate cases.
7		4. Secondary calculations necessary for a full cost of service study are based
8		on the results of the above items. For example:
9		a. Cash Working Capital balance related to the revenues and expenses
10		developed above;
11		b. Deferred Tax Asset balance and deferred tax expense related to a Net
12		Operating Loss calculation; and
13		c. Change in debt interest expense related to the budgeted change in
14		debt costs and the budget of rate base.
15		
16		B. Case Drivers
17	Q.	HAVE YOU PREPARED A COMPARISON OF THE COSTS IN THE MYRP FORECAST
18		TO CURRENT RATES RESULTING FROM THE 2016-2019 MYRP?
19	Α.	Yes. I provide an explanation of the detailed case drivers of the deficiency using
20		a comparison of the 2022 test year (including rider roll-ins) with the base rates
21		in effect in 2019 as a result of the MYRP in Docket No. E002/GR-15-826 (the
22		2016-2019 MYRP). ³ My analysis also includes a comparison of years two (2023)

³ 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 2022 test year.

and three (2024) of the MYRP. My analysis differs from the Direct Testimony analyses of the Company's business area witnesses, who discuss costs and cost changes in more detail and 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 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 COMPANY'S LAST ELECTRIC 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)

1'/		т	т	т	
		Increase	Increase	Increase	
18		(Decrease)	(Decrease)	(Decrease)	3-Year
		2022 TY	2023 TY	2024 TY	
19		to 2019	to 2022	to 2023	MYRP
20		MYRP	TY	TY	
20	Capital and Capital Related	\$543.2	\$70.5	\$82.0	\$695.7
21	Amortizations	17.2	(0.0)	(2.5)	14.7
22	Taxes	(94.2)	15.7	19.1	(59.5)
22	Operating Expense	(28.5)	37.5	18.5	27.5
23	Other Margin Impacts*	(41.7)	26.5	14.1	(1.1)
24	Total Net Incremental Deficiency	\$396.0	\$150.2	\$131.2	\$677.3

*Includes settlement Other Revenue credit (revenue requirement reduction) from the 2016-2019 MYRP Rate Case as filed in indicative cost of service in Docket No. E002/GR-15-826.

In addition to the discussion in this Section, support for our proposed increase in rates for the 2022 test year is provided in the Direct Testimonies of the Company's business area witnesses and the Direct Testimony of Company witness Ms. Melissa L. Ostrom.

5

- 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.

11

12

13

Table 4
Capital and Capital Related Cost Changes (\$ in millions)

14		Increase	Increase	Increase	
		(Decrease)	(Decrease)	(Decrease)	3-Year
15		2022 TY	2023 TY	2024 TY	MYRP
1.7		to 2019	to 2022	to 2023	
16		MYRP	TY	<u>TY</u>	
17	Nuclear	\$40.6	\$8.2	\$6.9	\$55.7
1 /	Steam	(15.4)	(17.8)	1.2	(32.0)
18	Wind	202.9	(20.1)	(12.9)	169.9
19	All Other Production	3.1	8.8	7.3	19.3
17	Transmission	84.9	13.3	12.4	110.6
20	Distribution	60.6	34.6	33.3	128.5
21	General and Intangible	56.5	28.2	19.4	104.1
41	DTA (Federal Credits & NOL)	19.2	10.9	10.5	40.6
22	Other Rate Base	(1.2)	(0.1)	(0.1)	(1.4)
23	Cost of Capital	92.0	4.3	4.0	100.4
43	TOTAL Capital and Capital	\$543.2	\$70.5	\$82.0	\$695.7
24	Related				

1 PLEASE DESCRIBE THE PRINCIPAL CHANGES IN NUCLEAR CAPITAL COSTS. Q. 2 Α. The MYRP Forecast revenue requirements include a \$55.7 million increase in 3 Nuclear. This increase is primarily due to capital investments for Nuclear Fuel, 4 Dry Cask Storage, Mandated Compliance, Reliability, and Improvements in the 5 MYRP forecast as well as incremental additions during the last MYRP period. 6 Additional information regarding nuclear projects is discussed in the Direct 7 Testimony of Company witness Mr. Peter A. Gardner. 8 9 WHAT ARE THE PRINCIPAL CHANGES IN WIND CAPITAL COSTS? Q. 10 The MYRP Forecast revenue requirements include a \$169.9 million increase to 11 Wind. This increase is due to capital investments for the Blazing Star II, 12 Freeborn, and Dakota Range Wind Farms, which are scheduled to be placed in 13 service in 2021. In addition, we anticipate rolling into base rates the Courtenay, 14 Foxtail, Blazing Star I and II, Lake Benton, Crowned Ridge, Jeffers, Community 15 Wind North, Mower, Freeborn and Dakota Range Wind Farms. Additional 16 information regarding wind projects are discussed in the Direct Testimony of 17 Company witness Mr. Randy A. Capra. 18 19 Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN TRANSMISSION CAPITAL COSTS. 20 Α. The MYRP Forecast revenue requirements include an \$110.6 million increase 21 to Transmission. This increase is due mainly to an increase in asset health 22 projects and the roll-in of large transmission capital projects, particularly the 23 CapX2020 projects from the Transmission Cost Recovery (TCR) Rider. 24 Additional information regarding transmission projects are discussed in the 25 Direct Testimony of Company witness Mr. Ian R. Benson.

PLEASE IDENTIFY THE PRINCIPAL CHANGES IN DISTRIBUTION CAPITAL COSTS.

1

22

23

24

Q.

2 The MYRP Forecast revenue requirements include an \$128.5 million increase 3 to Distribution. This increase is due to capital investments relating to increased 4 investment in Distribution's asset health and reliability programs to address the 5 portions of our system that are closest to our customers, such as pole and substation transformer replacements. This increase is also due to our Electric 6 7 Vehicle (EV) programs, support for new business and localized load growth, 8 and mandated relocation projects and tools and equipment. Distribution also 9 manages work associated with the Advanced Grid Intelligence & Security 10 (AGIS) initiative, but most AGIS costs are certified for inclusion in the TCR 11 Rider and are not reflected in base rates in this matter. Additional information 12 regarding distribution projects is discussed in the Direct Testimony of Company 13 witness Ms. Kelly A. Bloch. 14 15 WHAT ARE THE PRINCIPAL CHANGES IN GENERAL AND INTANGIBLE CAPITAL Q. 16 COSTS? 17 The MYRP Forecast revenue requirements include a \$104.1 million increase to 18 General and Intangible. This increase is primarily due to increasing technology 19 needs and capital investments relating to replacing aging technology, addressing 20 evolving cyber security threats and requirements, enhancing capabilities, 21 enhancing the customer experience, and addressing emergent demands. It also

Testimony of Company witness Mr. Michael O. Remington.

includes AGIS costs that are not included in the TCR Rider. Additional

information regarding general and intangible projects is discussed in the Direct

PLEASE DESCRIBE THE PRINCIPAL CHANGES IN COST OF CAPITAL.

1

25

Q.

2 The MYRP Forecast revenue requirements include an \$100.4 million increase 3 related to changes in cost of capital. The change in cost of capital is due to a 4 requested 10.2 percent return on equity (ROE), partially offset by a decrease in 5 the cost of long-term debt. Company witness Mr. Paul A. Johnson describes 6 the capital structure and costs of debt in his Direct Testimony. Company 7 witness Mr. Dylan D'Ascendis of ScottMadden, Inc. discusses the Company's 8 recommended ROE. 9 10 Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN AMORTIZATIONS. 11 The MYRP Forecast revenue requirements include a \$14.7 million increase Α. 12 related to amortizations. This increase is due to new amortizations for the 13 Aurora Deferral (discussed in adjustment 15 below), Net Operating Loss 14 (NOL) Tax Reform Regulatory Amortization (discussed in adjustment 20 15 below) and Income Tax Tracker Amortization (discussed in adjustment 18 16 below), as well as an increase in Rate Case Expense amortization (discussed in 17 adjustment 22 below). 18 19 PLEASE DESCRIBE THE PRINCIPAL CHANGES IN TAXES. Q. 20 The MYRP Forecast revenue requirements include a \$59.5 million decrease to Α. 21 This decrease is due to increased Production Tax Credits (PTCs) taxes. 22 associated with new and existing wind farms being moved to base rate recovery 23 in this case partially offset by an increase in income and property taxes. 24 Additional information regarding property taxes is discussed in the Direct

Testimony of Company witness Mr. Christopher A. Arend.

- 1 Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN O&M COSTS.
- 2 A. Table 5 below compares the MYRP Forecast revenue requirements with the
- 3 comparable revenue requirements for the 2019 MYRP plan year, by category,
- for operating expenses as shown on Schedule 6, Detailed Case Drivers.

5

Table 5

O&M Cost Changes (\$ in millions)

8		Increase	Increase	Increase	
O		(Decrease)	(Decrease)	(Decrease)	3-Year
9		2022 TY	2023 TY	2024 TY	MYRP
4.0		to 2019	to 2022	to 2023	WITT
10		MYRP Year	TY	TY	
11	Nuclear	(\$84.4)	\$7.1	\$4.8	(\$72.5)
11	Steam	(47.4)	7.0	(5.2)	(45.6)
12	Wind	31.4	(6.0)	(2.7)	22.7
13	Purchased Demand	14.3	2.7	2.8	19.8
13	All Other Production	11.4	10.2	(3.9)	17.7
14	Transmission	30.5	(0.0)	2.2	32.6
15	Transmission Interchange	(16.6)	8.4	4.2	(4.0)
13	Distribution	9.6	5.7	1.9	17.2
16	Regional Markets	2.3	0.3	0.2	2.8
17	Customer Accounting / Info /	8.1	(4.4)	6.4	10.1
1 /	Service				
18	A&G	12.4	6.5	7.8	26.7
19	TOTAL O&M	(\$28.5)	\$37.5	\$18.5	\$27.5

20

- Q. What are the reasons for the decrease in Nuclear Operations operating expense?
- A. The MYRP Forecast revenue requirements include a \$72.5 million decrease in nuclear operating expenses. This decrease is due to reductions in internal labor and contractor costs and materials, reduced materials and chemicals, and reductions in outage costs in 2020 and 2021, which flow through to subsequent

_		
1		years through the deferral and amortization of these costs. Additional
2		information regarding nuclear operating expenses is discussed by Mr. Gardner.
3		
4	Q.	WHAT ARE THE REASONS FOR THE DECREASE IN STEAM OPERATING EXPENSE?
5	Α.	The MYRP Forecast revenue requirements include a \$45.6 million decrease in
6		steam operating expenses. This decrease is due to reduced overhaul and project
7		investments as several units approach retirement. Additional information
8		regarding overhauls is discussed by Mr. Capra.
9		
10	Q.	WHAT ARE THE REASONS FOR THE INCREASE IN WIND OPERATING EXPENSE?
11	Α.	The MYRP Forecast revenue requirements include a \$22.7 million increase in
12		wind operating expenses. This increase is due to the additional operating
13		expense, specifically operations and maintenance contracts and land easement
14		payments associated with new wind farms that have been or will be added to
15		our generation portfolio, as discussed by Mr. Capra.
16		
17	Q.	WHAT ARE THE REASONS FOR THE INCREASE IN PURCHASED DEMAND
18		OPERATING EXPENSE?
19	Α.	The MYRP Forecast revenue requirements include a \$19.8 million increase in
20		purchased demand operating expenses. The increase is due to a known increase
21		in overall contracted capacity due to a new contract with Manitoba Hydro that
22		increased the capacity purchases by 125 MW starting in 2021 as well as annual
23		price increases in the capacity contracts.
		price mercuses in the cupucity continues.

1	Q.	WHAT ARE THE REASONS FOR THE INCREASE IN ALL OTHER PRODUCTION
2		OPERATING EXPENSE?
3	Α.	The MYRP Forecast revenue requirements include a \$17.7 million increase in
4		all other production operating expenses. This increase is due to changes in the
5		NSPW Interchange Agreement bill to NSPM, primarily due to increased capital
6		investment. A significant portion of the increase in 2022 and 2023 is due to the
7		addition of a NSPW solar farm.
8		
9	Q.	WHAT ARE THE REASONS FOR THE INCREASE IN TRANSMISSION OPERATING
10		EXPENSE?
11	Α.	The MYRP Forecast revenue requirements include a \$32.6 million increase in
12		Transmission operating expenses. This increase is primarily due to a change in
13		the TCR Removal adjustment compared to the 2016-2019 MYRP. In the 2022-
14		2024 MYRP, the adjustment removes the Minnesota jurisdictional share (net of
15		IA) of the costs including the Regional Expansion Criteria and Benefits (RECB)
16		expense; however, in the 2016-2019 MYRP, the rider removal removed the
17		gross RECB expense and included an offset in other revenue for the IA portion.
18		The change in methodology was made in the 2022-2024 MYRP to better align
19		with the presentation of the Cost of Service Study (COSS).
20		
21	Q.	What are the reasons for the decrease in Transmission Interchange
22		OPERATING EXPENSE?
23	Α.	The MYRP Forecast revenue requirements include a \$4.0 million decrease in
24		transmission interchange operating expenses. This decrease is due to lower
25		transmission rate base and a decrease in the Interchange ROE.

1	Q.	WHAT ARE THE REASONS FOR THE INCREASE IN DISTRIBUTION OPERATING
2		EXPENSE?
3	Α.	The MYRP Forecast revenue requirements include a \$17.2 million increase in
4		distribution operating expenses. This increase is due to increased Vegetation
5		Management work, increased O&M to implement the AGIS initiative, and
6		increases in Asset Health and Reliability projects, as discussed in the Direct
7		Testimony of Ms. Bloch.
8		
9	Q.	What are the reasons for the increase in Administrative and
10		GENERAL (A&G) EXPENSE?
11	Α.	The MYRP Forecast revenue requirements include a \$26.7 million increase in
12		A&G expense. This increase is due to increases in Business Systems costs
13		related to the Company's additional software licensing and maintenance cost
14		increases, increased network services, Company labor costs (offset somewhat
15		by reduced contractor costs) and increases in insurance costs. Additional
16		information regarding Business Systems O&M is discussed by Mr. Remington.
17		Additional information regarding insurance costs is provided by Company
18		witness Mr. Robert L. Miller.
19		
20	Q.	PLEASE DESCRIBE HOW CHANGES IN SALES RELATE TO THE RATE INCREASE.
21	Α.	As discussed by Company witness Mr. John Goodenough, Minnesota electric
22		sales steadily declined from 2008 through 2019 before showing a sharper decline
23		in 2020 due to the impacts of the COVID-19 pandemic. Although Residential
24		sales were strong in 2020, those increases were offset by larger reductions in the
25		Commercial and Industrial sector and we expect overall sales to continue to be
26		relatively flat through the MYRP based primarily on reduced consumption.

1		Consequently, the Company's retail revenues show a significant decrease in the
2		2022 test year as compared to the 2019 plan year from the Company's last rate
3		case and are expected to decrease slightly over the 2023 and 2024 plan years,
4		increasing the MYRP revenue deficiency.
5		·
6	Q.	ARE THERE ANY OTHER MARGIN ITEMS WITH A SIGNIFICANT IMPACT ON THE
7		2022 REVENUE DEFICIENCY?
8	Α.	The MYRP Forecast revenue requirements include a \$158.2 million increase in
9		rider revenue since the illustrative test year from our prior MYRP, which acts
10		as an offset to the net revenue deficiency when rolled into base rates. As
11		discussed in further detail in Section VII, Annual Adjustments to the MYRP,
12		Part D. Rider Removals, of my testimony, there are a number of projects
13		currently recovered through the TCR and RES riders that we are proposing to
14		roll into base rates at the implementation of final rates and this increase is
15		revenue is attributed to those projects. It is also worth noting that while the
16		Tax Cut and Jobs Act (TCJA) was implemented midway through the 2016-2019
17		MYRP, TCJA impacts are currently being refunded to customers in base rates,
18		as approved in the Commission's Order in Docket No. E,G999/CI-17-895, and
19		are included in the baseline numbers for the cost of service. As such, they will
20		not appear as a driver of the 2022 revenue deficiency.
21		
22	Q.	Are the functional class categories of Operating Expense
23		COMPARABLE BETWEEN THE 2022 TEST YEAR AND THE DOCKET NO.
24		E002/GR-15-826 2019 PLAN YEAR?
25	Α.	Yes. Budget amounts for both periods conform to the Federal Energy
26		Regulatory Commission (FERC) Uniform System of Accounts. To better show

1		cost drivers, especially as they relate to operating margins, some reclassifications
2		are made in the cost driver analysis from the Jurisdictional COSS.
3		
4	Q.	DID YOU INCLUDE COMPARISONS OF THE CHANGE IN THE FUEL AND
5		PURCHASED ENERGY EXPENSE AS PART OF THE O&M EXPENSE ANALYSIS?
6	Α.	No. Although the cost of fuel and purchased energy are considered to be an
7		operating expense, recovery occurs through the Company's separate fuel clause
8		adjustment (FCA) mechanism and true-up process. I provide a reconciliation
9		of fuel costs and revenues in Exhibit(BCH-1), Schedule 21, Fuel
10		Reconciliation.
11		
12		III. SUPPORTING INFORMATION
13		
14	Q.	WHAT TOPICS DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?
15	Α.	In this section, I provide information related to data provided in our application,
16		the selection of the test year and, the jurisdictional cost of service study.
17		
18		A. Data Provided and Selection of the Test Year
19	Q.	WHAT TOPICS DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?
20	Α.	In this section, I will:
21		• identify the supporting financial information and related fiscal periods
22		that we are providing in connection with the MYRP Forecast; and
23		demonstrate that the supporting financial information and related fiscal
24		periods that we are presenting provide appropriate information and
25		facilitate review of our MYRP Forecast.

1		1) Overview
2	Q.	PLEASE DEFINE THE FISCAL PERIODS FOR WHICH FINANCIAL DATA IS PROVIDED
3		IN THIS PROCEEDING.
4	Α.	Following the Commission's rules, financial data is provided for 2020 (the most
5		recent fiscal year), 2021 (the projected fiscal year), and 2022 (the test year). In
6		addition, we provide financial data to support the MYRP Forecast. The most
7		recent fiscal year (calendar year 2020) reflects the Company's actual financial
8		results. For the projected fiscal year 2021, actual financial results through June
9		2021 are provided as rate base data, operating expenses, and revenues. Forecast
10		projections are provided for the remainder of 2021. The MYRP Forecast
11		reflects the Company's most recent available budget data.
12		
13		All fiscal periods provided in this testimony are adjusted for traditional
14		regulatory adjustments (e.g., charitable donations, etc.).
15		
16		I also provide schedules showing: the actual unadjusted average rate base
17		consisting of the same rate base components; unadjusted operating income;
18		overall rate of return; the calculation of required income; and the income
19		deficiency and revenue requirements for the most recent fiscal year (2020); the
20		projected fiscal year (2021); and the MYRP Forecast. Separate rate base and
21		income statement bridge schedules for the MYRP Forecast that identify test
22		period adjustments are provided with my testimony.

1		2) MYRP Forecast
2	Q.	WHAT WAS THE BASE SOURCE FOR THE PROPOSED MYRP FORECAST COSTS?
3	Α.	Calendar year 2022 was selected as the test year for this filing using Xce
4		Energy's most recent available budget data for the first year of the budget cycle
5		Use of a fully projected calendar test year (2022) is consistent with longstanding
6		practice and precedent in the Company's rate cases before the Commission.
7		
8		The 2023 and 2024 plan years reflect years two and three from the most recent
9		available budget information, of which the 2022 test year is year one. Unlike
10		our 2016-2019 MYRP, our plan year O&M is based on the budget for those
11		years as opposed to using escalations from the test year budget. Using the same
12		budget vintage for the test year and plan years allows for a consistent MYRF
13		Forecast.
14		
15		The 2022-2024 Budget is supported in Ms. Ostrom's Direct Testimony and
16		provided in Volumes 5 (Budget Summary and Documentation) and 6 (Budget
17		Documentation) of the Application.
18		
19	Q.	DOES THE COMPANY ANTICIPATE UPDATING SOME OF ITS INFORMATION IN
20		REBUTTAL TESTIMONY?
21	Α.	Yes. Consistent with prior cases, we will update certain costs to incorporate
22		updated information. More specifically, as in our 2016-2019 MYRP, we will
23		review the following and update in this case as appropriate:
24		 Cost of capital to reflect the most currently available data;

1		• Current customer count and sales information and expected trends that
2		might indicate that adjustments to the sales and customer counts forecast
3		are needed;
4		• Assumptions used for calculating Qualified Pension, FAS 106 retiree
5		medical, and FAS 112 post-employment benefits expense based on
6		information as of December 31, 2021;
7		• O&M active health care may be updated to reflect actual 2021 active
8		medical and pharmacy claims; and
9		• Property tax forecasts based upon property tax data that will become
10		available during 2022.
11		
12		3) Supporting Information and the 2022 Projected Test Year
13	Q.	Why does the Company use $2020\mathrm{as}$ its most recent fiscal year instead
14		OF 2021?
15	Α.	Minn. R. 7825.3100, Subp. 10 provides the following definition:
16 17 18 19 20 21 22 23		"Most recent fiscal year" is the <i>utility's prior fiscal year [here, 2020] unless</i> 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. (Emphasis added.)
24		In this proceeding, the Company's prior fiscal year is 2020, and its current fiscal
25		year is 2021 because the two exceptions to the rule that would instead convert
26		2021 into the most recent fiscal year are not fulfilled. While the Company is
27		filing this rate case within the last three months of 2021, nine months of actual
28		2021 data is not "available for presentation." Since that requirement cannot be

1 met, the plain language of the Rule directs the Company to use 2020 as the most 2 recent fiscal year, consistent with the Company's long-standing approach.

3

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Nothing in the Rule requires the Company to delay its filing until additional 2021 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 2020 as the prior fiscal year and Minn. R. 7825.3100, Subp. 12 requires that we treat 2021 as the projected fiscal year.

9

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

12 Α. Yes. In our rate case in Docket E002/GR-12-961, the Administrative Law 13 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 14 ALJ supported,⁴ and the Commission adopted, the Company's use of a fully 15 16 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 17 18 was not available for presentation at the time of that filing. There was no issue with that approach in that case.⁵ 19

⁴ ALJ Report Findings 866-873 in Docket No. E002/GR-12-961 (July 3, 2013).

⁵ 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 (2016 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 2020 data is consistent with the Minnesota Rule under the circumstances of this filing. But if the 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 2021, and it would be an excessive burden on the utility to wait to file the case or

1 DOES THE COMPANY'S PRACTICE RESULT IN LESS INFORMATION BEING O. 2 INCLUDED IN THE FILING? 3 No. The Company filed information for 2020 (the most recent fiscal year), 2021 4 (the projected year), the unadjusted 2022 year, the adjusted 2022 test year, and 5 the 2023-2024 plan years. Definitions and financial schedules related to 2020 6 actual and 2021 projections are included in the following locations. 7 • Volume 3, Required Information, Section II: - Tab 2, Jurisdictional Financial Summary Schedules, Schedule A-1 8 9 - Tab 3, Rate Base Schedules, Section A, Schedule A-1 10 Tab 3, Rate Base Schedules, Section B, Schedule B-2 11 Tab 3, Rate Base Schedules, Section E, Schedule E, Page 2 12 Tab 4, Operating Income Schedules, Section A, Schedule A-1 13 Tab 4, Operating Income Schedules, Section B, Schedule B-1 14 Tab 4, Operating Income Schedules, Section C, Schedules C-1 and C-3 15 Tab 4, Operating Income Schedules, Section F, Schedule F, Page 2 16 Tab 5, Rate of Return Cost of Capital Schedules, Sections A-D; 17 Exhibit (BCH-1), Schedule 7, Comparison of Detailed Rate Base 18 Components; Exhibit ___(BCH-1), Schedule 8, Comparison of Detailed Income 19 20 Statement Components.

refile the case when 2021 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.

Docket No. E002/GR-21-630 Halama Direct

1		B. Jurisdictional Cost of Service Study
2	Q.	WHAT TOPICS DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?
3	Α.	In this section, I will explain the jurisdictional cost of service studies that we
4		prepared for the MYRP Forecast.
5		
6	Q.	PLEASE DESCRIBE THE COMPONENTS OF THE JURISDICTIONAL COST OF SERVICE
7		STUDY FOR THE MYRP Forecast.
8	Α.	A summary of the jurisdictional cost of service study for the MYRP Forecast is
9		provided in Schedule 2, Summary of Revenue Requirements. The complete
10		jurisdictional cost of service study for the MYRP Forecast provided in Schedule
11		3, Cost of Service Study Summary, and in Volume 4, Section II, Cost of Service
12		Study (COSS) of this filing and include all the adjustments discussed in my
13		Direct Testimony.
14		
15		The jurisdictional cost of service study includes the following financial data
16		input sections, for both Total Company and the Minnesota Jurisdiction:
17		(i) capital structure; (ii) cost of capital; (iii) income tax rates; (iv) rate base; (v)
18		income statement; (vi) income tax calculations; and (vii) cash working capital.
19		
20	Q.	PLEASE DESCRIBE THE JURISDICTIONAL COST OF SERVICE SUMMARY
21		SCHEDULES.
22	Α.	The jurisdictional cost of service summary for each year of the MYRP Forecast
23		is included as Schedule 3, Cost of Service Study Summary:
24		• The Rate Base Summary for the Minnesota jurisdiction is shown on Page
25		1. It provides the assumed capital structure, including the earned overall
26		rate of return on rate base and the earned ROE. The Rate Base Summary

1		references a calculation of cash working capital, which is detailed in
2		Exhibit(BCH-1), Schedule 4 (Cash Working Capital), and Volume 4
3		Section III, Rate Base (Plant), Tab P10, Cash Working Capital.
4		• An Income Statement for the Minnesota jurisdiction is shown on Page 2
5		and Page 3. The income statement shows the determination of tota
6		operating income at present authorized retail rates. The Income
7		Statement references calculations for federal and state income taxes
8		which are detailed on Page 3.
9		• The Revenue Requirement and Return Summary for the Minnesota
10		jurisdiction is shown on Page 4. It shows the revenue deficiency that
11		needs to be recovered to enable the Minnesota jurisdiction electric
12		operations to earn the requested ROE and the total revenue
13		requirements and the percent of increase that would result by increasing
14		retail billing rates by the amount of the revenue deficiency.
15		
16	Q.	ARE THE REVENUE CONVERSION FACTOR CALCULATION AND THE MINNESOTA
17		COMPOSITE INCOME TAX RATES INCLUDED IN THIS FILING?
18	Α.	Yes. The revenue conversion factor calculation is included in Volume 3, Section
19		II.7, Required Financial Information, Other Supplemental Information, Tab B
20		Gross Revenue Conversion Factor; and composite income tax rates are
21		included in Volume 3, Section II.4, Required Financial Information, Operating
22		Income Schedules, Tab C, Income Tax Computation, Schedule C-5.

1	Q.	PLEASE EXPLAIN HOW THE INTEREST DEDUCTION FOR DETERMINING TAXABLE
2		INCOME IS CALCULATED.
3	Α.	The amount of interest deducted for income tax purposes is the weighted cost
4		of debt capital multiplied by the average rate base. This is sometimes called
5		"interest synchronization." The MYRP calculation for the interest
6		synchronization is provided in Schedule 3, Cost of Service Summary, line 110.
7		
8	Q.	WHICH SCHEDULES ATTACHED TO YOUR TESTIMONY ARE RELATED TO RATE
9		BASE?
10	Α.	I have provided three schedules related to rate base: Schedule 7, Comparison of
11		Detailed Rate Base Components; Exhibit(BCH-1) Schedules 10a-10c, 2022-
12		2024 Rate Base Adjustment Schedules; and Exhibit(BCH-1) Schedule 9,
13		Rate Base, CWIP, and ADIT Summary. I discuss these schedules in Section
14		IV; Rate Base and Section VII, Annual Adjustments to the MYRP. Additional
15		comparative rate base schedules are provided in Volume 3, Required
16		Information.
17		
18	Q.	WHICH SCHEDULES TO YOUR TESTIMONY ARE RELATED TO THE INCOME
19		STATEMENT?
20	Α.	I have provided two schedules related to the income statement: Schedule 8,
21		Comparison of Detailed Income Statement Components, and
22		Exhibit(BCH-1), Schedules 11a-11c, 2022-2024 Income Statement
23		Adjustment Schedules. I discuss these schedules in Section V, Income
24		Statement and Section VII, Annual Adjustments to the MYRP. Additional
25		comparative income statement schedules are provided in Volume 3, Required
26		Information.

1		IV. RATE BASE
2		
3	Q.	WHAT TOPICS DO YOU ADDRESS IN THIS SECTION OF YOUR TESTIMONY?
4	Α.	In this section of my testimony, I support the reasonableness of the Company's
5		projected 2022-2024 MYRP rate base and identify and explain how the
6		components of the rate base were determined, focusing on the 2022 test year
7		and noting any limited situations where there are differences for the other years
8		of the MYRP. I begin by providing the overall rate base calculation and identify
9		its components, then walk through each of the MYRP Forecast components of
10		rate base in turn.
11		
12	Q.	Is the Company's projected 2022 test year rate base reasonable for
13		PURPOSES OF DETERMINING FINAL RATES IN THIS PROCEEDING?
14	Α.	Yes. The projected 2022 test year rate base for the Company's Minnesota
15		jurisdiction electric operations was developed using sound ratemaking
16		principles and in a manner similar to prior Company electric rate cases. This is
17		also true of the 2023-2024 plan years.
18		
19	Q.	PLEASE EXPLAIN WHAT RATE BASE REPRESENTS.
20	Α.	Rate base primarily reflects the capital expenditures made by a utility to secure
21		plant, equipment, materials, supplies, and other assets necessary for the
22		provision of utility service, reduced by amounts recovered from depreciation
23		and non-investor sources of capital.

1	Q.	PLEASE IDI	ENTIFY THE MAJOR COMPONENTS OF THE PROJECTED 2022-2024	
2		MYRP RAT	E BASE.	
3	Α.	The MYRP	rate base is generally composed of the following major items, which	
4		I later descr	ribe in detail:	
5		• Net	Utility Plant;	
6		• Cons	struction Work in Progress (CWIP);	
7		• Accu	amulated Deferred Income Taxes (ADIT);	
8		• Pre-l	Funded Allowance for Funds Used During Construction (AFUDC);	
9		and		
10		• Other Rate Base.		
11				
12	Q.	How does	THE COMPANY CALCULATE RATE BASE?	
13	Α.	The Compa	any's rate base can be expressed using the breakdown on Page 27 of	
14		the "Electric Utility Cost Allocation Manual" of the National Association of		
15		Regulatory Utility Commissioners (NARUC) as follows:		
16				
17			Original Average Cost of Electric Plant in Service (Plant)	
18		Less:	Average Accumulated Depreciation Reserve (Reserve)	
19		Less:	Average Accumulated Provision for Deferred Taxes	
20			(net of accts 281-283 and 190) (ADIT)	
21		Plus:	Average Construction Work in Progress (CWIP)	
22		Plus:	Average Working Capital (Work Cap)	
23		Equals:	Rate Base	

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

3	Plant	\$22,725,537	(per BCH-1, Schedule 3, Page 1, Line 23)
4	Reserve	(10,346,933)	(per BCH-1, Schedule 3, Page 1, Line 24)
5	ADIT	(2,178,105)	(per BCH-1, Schedule 3, Page 1, Line 32)
6	CWIP	436,833	(per BCH-1, Schedule 3, Page 1, Line 26)
7	Other Rate Base	294,039	(per BCH-1, Schedule 3, Page 1, Line 42)
8	Rate Base	\$10,931,371	(thousands of dollars)

9

10 Q. PLEASE DESCRIBE THE SCHEDULES IN YOUR EXHIBIT THAT ARE RELATED TO 11 THE TEST YEAR AVERAGE INVESTMENT IN RATE BASE.

12 Schedule 7, Comparison of Detailed Rate Base, provides a detailed statement Α. 13 of the rate base components. Page 1 provides a comparison of the rate base 14 components for the 2022 test year to the 2019 plan year used in our 2016-2019 MYRP. Page 2 provides the rate base components for the MYRP Forecast. 15

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Schedule 9, Rate Base, CWIP, and ADIT Summary, Page 1 of 4, shows a detailed average rate base by component for the 2022 test year for the Minnesota jurisdiction and Total Company, before and after making proposed test period adjustments. Page 2 shows the 2023 and 2024 plan years 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.

1		Schedules 10a-10c, 2022-2024 Test/Plan Year Rate Base Adjustment Schedules,
2		are a bridge schedule showing the 2022-2024 unadjusted rate base, each
3		proposed rate base adjustment, and the resulting proposed 2022-2024 test/plan
4		year rate base.
5		
6		A. Net Utility Plant
7	Q.	WHAT DOES NET UTILITY PLANT REPRESENT?
8	Α.	Net utility plant represents the Company's investment in plant and equipment
9		that is used and useful in providing retail electric service to its customers, net
10		of accumulated depreciation and amortization.
11		
12	Q.	PLEASE EXPLAIN THE METHOD USED TO CALCULATE NET UTILITY PLANT
13		INVESTMENT IN THIS CASE.
14	Α.	The net utility plant is included in rate base at depreciated original cost reflecting
15		the simple average of projected net plant balances at the beginning and end of
16		the 2022 test year. Such treatment is consistent with the method employed in
17		the Company's most recent Minnesota electric rate case.
18		
19	Q.	WHAT HISTORICAL BASE DID THE COMPANY USE AS A STARTING POINT TO
20		DEVELOP THE PROJECTED NET PLANT BALANCES FOR THE BEGINNING OF THE
21		2022 TEST YEAR?
22	Α.	The historical base used for the beginning of the 2022 test year was the
23		Company's actual net investment (Plant in Service less Accumulated
24		Depreciation) on the Company's books and records as of June 30, 2021 plus
25		the forecast for the remaining months of 2021. Similarly, the 2023 and 2024
26		projected beginning net plant balances are based on the forecasted balances at

	the end of 2022 and 2023, respectively, as walked forward from the actual net
	investment as of June 30, 2021.
Q.	ON WHAT BASIS WERE NET PLANT BALANCES PROJECTED FOR THE END OF THE
	2022 TEST YEAR?
Α.	The 2022 test year ending net plant balances were determined by applying the
	data contained in the 2022 capital budget to the above-described beginning test
	year balances, adjusted for retirements, depreciation, salvage and removal costs
	projected to occur during the 2022 test year. The same methodology was
	utilized to establish 2023 and 2024 end-of-year projected net plant balances.
Q.	What was the average net utility plant included in the 2022 test
	YEAR RATE BASE?
Α.	The average net utility plant included in the 2022 test year rate base is \$12.379
	billion, as shown on Schedule 7, Comparison of Detailed Rate Base
	Components. This is comprised of an average plant balance of \$22.726 billion
	as detailed on Schedule 7, minus an average depreciation reserve of \$10.347
	billion, also shown by component on Schedule 7.
	B. Construction Work In Progress (CWIP)
Q.	WHAT IS CONSTRUCTION WORK IN PROGRESS?
Α.	In Minnesota, 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.
	A. Q. A.

1	Q.	HAS CWIP BEEN INCLUDED IN THE 2022 TEST YEAR AND 2023-2024 PLAN
2		YEARS RATE BASE?
3	Α.	Yes. CWIP is included in rate base with a corresponding offset of AFUDC
4		added to operating income, except where the Company is allowed to earn a
5		current return. The rate base amount reflects a simple average of projected
6		CWIP beginning and ending balances. This is consistent with the method
7		employed in Minnesota and approved by the Commission in the Company's
8		2016-2019 MYRP and matches the use of an average rate base. The CWIP and
9		AFUDC determinations for rate base are discussed in the Direct Testimony of
10		Company witness Mr. Mark P. Moeller.
11		
12	Q.	How were the 2022 test year beginning and ending CWIP balances
13		DETERMINED?
14	Α.	The beginning balance for CWIP was the June 30, 2021 historical balance. The
15		beginning CWIP balance was adjusted to reflect projected construction
16		expenditures, AFUDC, and transfers to Plant in Service during the remainder
17		of 2021 and in 2022 to obtain the beginning and ending 2022 test year CWIP
18		balance. These projections were developed from the Company's 2022 capital
19		budget. The same methodology was utilized to establish 2023 and 2024 end-
20		of-year CWIP balances.
21		
22		C. Accumulated Deferred Income Taxes (ADIT)
23	Q.	PLEASE DESCRIBE ACCUMULATED DEFERRED INCOME TAXES.
24	Α.	Inter-period differences exist between the book and taxable income treatment
25		of certain accounting transactions. These differences typically originate in one
26		period and reverse in one or more subsequent periods. For utilities, the largest

1		such timing difference typically is the extent to which accelerated income tax
2		depreciation exceeds book depreciation during the early years of an asset's
3		service life. ADIT represents the cumulative net deferred tax amounts that have
4		been allowed and recovered in rates in previous periods.
5		
6	Q.	WHY IS ADIT DEDUCTED IN ARRIVING AT TOTAL RATE BASE?
7	Α.	To the extent income taxes recovered in rates are deferred for later payment,
8		they represent a prepayment by customers, a non-investor source of funds. The
9		average projected ADIT balance is deducted in arriving at total rate base to
10		recognize such funds are available for corporate use between the time they are
11		collected in rates and ultimately remitted to the respective taxing authorities.
12		
13	Q.	What amount of ADIT was deducted to arrive at the 2022-2024 MYRP
14		TEST YEAR RATE BASE?
15	Α.	As shown on Schedule 7, Comparison of Detailed Rate Base Components,
16		\$2.178 billion was deducted for the 2022 test year. This amount reflects a simple
17		average of the projected beginning and ending 2022 test year ADIT balances
18		and incorporates Internal Revenue Service (IRS) tax regulations. Specifically,
19		Sec. 1.167(l) of the tax code defines a prorated schedule for the extent average
20		accumulated deferred income taxes can be used to reduce rate base to comply
21		with the tax normalization requirements of the Code when forecast information
22		is used to set rates. Details related to the full MYRP Forecast ADIT are
23		provided in Schedule 9, Rate Base, CWIP and ADIT Summary, on Page 4 of 4,
24		and are discussed in more detail by Mr. Moeller.

1	Q.	HAS THE COMPANY INCORPORATED THE EFFECTS OF THE TCJA INTO THE
2		PROPOSED MYRP ADIT IN RATE BASE?
3	Α.	Yes. As I previously noted, the Commission's Order in Docket No.
4		E,G999/CI-17-895 directed the Company's amortizations of excess ADIT,
5		which are included in the amounts shown on Schedule 7, Comparison of
6		Detailed Rate Base Components, Pages 1 and 2. Additional information
7		regarding the TCJA's effect on the deferred taxes associated with plant assets is
8		addressed by Mr. Moeller. Support for the excess ADIT can be found in
9		Volume 4, Section III Rate Base (Plant), Tab P2-3.
10		
11		D. Pre-Funded AFUDC
12	Q.	WHAT IS PRE-FUNDED AFUDC?
13	Α.	In Minnesota, AFUDC is included as part of the revenue requirement
14		calculation for base rates. Specifically, during construction, AFUDC is
15		calculated and included in the CWIP balance and is also included in operating
16		income as an offset to the revenue requirement. AFUDC is added to the cost
17		of related capital projects and is reflected in rate base when the related capital
18		project is placed into service. Once a project is placed in-service, the recording
19		of AFUDC ceases, and the total capital cost of the project including
20		accumulated AFUDC is recovered through depreciation.
21		
22		However, certain rate riders in Minnesota (e.g., the TCR Rider and the
23		Renewable Energy Standards (RES) Rider) include a current return on CWIP
24		as part of the revenue requirement calculation for the rider. The capital projects
25		associated with those riders do not include the accumulated AFUDC as part of

	rate base. Pre-funded AFUDC is needed to offset the accumulated AFUDC to
	align with the current return on CWIP in a rider.
Q.	How is Pre-Funded AFUDC treated?
Α.	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?
Α.	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 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
	A.

period as the associated asset.

23

- 1 Q. How have you treated Pre-funded AFUDC in the 2022-2024 MYRP?
- 2 A. All Minnesota jurisdictional Pre-funded AFUDC has been directly assigned to 3 the Minnesota jurisdiction, according to the functional class of the associated
- 4 asset for CWIP, Depreciation Reserve, Plant in Service, and ADIT in rate base,
- 5 and to depreciation and deferred taxes, and AFUDC on the income statement.
- 6 Accumulated Pre-funded AFUDC is a reduction to rate base, with the
- 7 amortization of the Pre-funded AFUDC balance being a reduction to
- 8 depreciation expense. The deferred taxes associated with Pre-funded AFUDC
- 9 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
- 14 Minnesota, North Dakota, and South Dakota jurisdictions based on 12
- 15 coincident peak demand. This allocation method is consistent with treatment
- of the underlying transmission assets and their associated expenses and
- 17 revenues.

18

19

E. Other Rate Base

- 20 Q. Please summarize the Items you have included in Other Rate Base.
- 21 A. Other Rate Base is composed primarily of Working Capital. It also includes
- certain unamortized balances that are the result of specific ratemaking
- 23 amortizations, as discussed below in my testimony.

1	Q.	PLEASE EXPLAIN WHAT WORKING CAPITAL REPRESENTS.
2	Α.	Working Capital is the average investment in excess of net utility plant provided
3		by investors that is required to provide day-to-day utility service. It includes
4		items such as materials and supplies, fuel inventory, prepayments, and various
5		non-plant assets and liabilities. The net cash requirement (referred to as Cash
6		Working Capital) is shown separately.
7		
8	Q.	How were 2022-2024 MYRP Materials and Supplies and Fuel
9		INVENTORY REQUIREMENTS CALCULATED?
10	Α.	The Materials and Supplies average balance included in the MYRP rate base are
11		included on Schedule 3, Cost of Service Study Summary Page 1, Line 35, for
12		each year of the MYRP Forecast. The MYRP average rate base amount for
13		Fuel Inventory is included on Schedule 3, Cost of Service Study Summary Page
14		1, Line 36, for each year of the MYRP Forecast. The Materials and Supplies
15		and Fuel Inventory amounts shown on Schedule 3 Page 1, Cost of Service Study
16		Summary, are based on the 13-month average balances ending June 30, 2021,
17		the most recent data available.
18		
19	Q.	How were 2022-2024 MYRP Non-Plant Assets and Liabilities
20		DETERMINED?
21	Α.	These balances, as shown on Schedule 3 Page 1, Cost of Service Study
22		Summary, represent 2022-2024 estimates of these balances. Any book/tax
23		timing differences associated with these items have been reflected in the
24		determination of current and deferred income tax provision and ADIT
25		balances previously discussed. The Non-Plant Assets and Liabilities average

1		balance are included on Schedule 3, Cost of Service Study Summary Page 1,
2		Line 37, for each year of the MYRP Forecast.
3		
4	Q.	How were 2022-2024 MYRP Prepayments and Other Working Capital
5		ITEMS DETERMINED?
6	Α.	Prepayments and Other Working Capital, such as customer advances and
7		deposits, are based on the actual 13-month average balances during the period
8		ended June 30, 2021, as a proxy for the 2022-2024 MYRP. Our nuclear outage
9		amortization is also included in Other Working Capital. The average rate base
10		for nuclear outage amortization is based on the average of the beginning of
11		year and end of year balances. The unamortized balances included in this
12		section are based on the amortization schedules as described in Section IV. The
13		Prepayments and Other Working Capital average balances are included on
14		Schedule 3, Cost of Service Study Summary Page 1, Lines 38-40, for each year
15		of the MYRP Forecast.
16		
17	Q.	HOW WERE THE MYRP FORECAST CASH WORKING CAPITAL REQUIREMENTS
18		DETERMINED?
19	Α.	Cash Working Capital requirements have been determined by applying the
20		results of a comprehensive lead/lag study to the projected MYRP Forecast
21		revenues and expenses.

Q. WERE THE COMPONENTS OF THE MYRP FORECAST CASH WORKING CAPITAL

1

2		CALCULATED CONSISTENT WITH METHODS USED IN THE 2016-2019 MYRP?
3	Α.	Yes. The current MYRP Forecast cash working capital has been calculated
4		consistent with methods accepted in our most recent completed Minnesota
5		electric rate case.
6		
7	Q.	PLEASE BRIEFLY EXPLAIN HOW A LEAD/LAG STUDY MEASURES CASH WORKING
8		CAPITAL.
9	Α.	A lead/lag study is a detailed analysis of the time periods involved in the utility's
10		receipt and disbursement of funds. The study measures the difference in days
11		between the date services to a customer are rendered and the revenues for that
12		service are received, and the date the costs of rendering the services are incurred
13		until the related disbursements are actually made.
14		
15	Q.	HAS XCEL ENERGY'S LEAD/LAG STUDY BEEN UPDATED SINCE THE 2016-2019
16		MYRP RATE CASE?
17	Α.	Yes. The Company has updated the lead/lag study for the calculation of the
18		lead and lag days for all categories through year-end 2020, using the
19		methodology for calculating the lead/lag days consistent with the Company's
20		prior electric and gas regulatory filings. The results of the updated lead/lag
21		study for electric operations were incorporated into the Minnesota jurisdiction
22		cash working capital calculations as shown on Schedule 3, Cost of Service Study
23		Summary, Page 1.

WHAT ARE THE CURRENT MYRP FORECAST CASH WORKING CAPITAL

1

Q.

2 AMOUNTS? 3 The amounts included as a reduction in average rate base in the MYRP Forecast Α. 4 are based on the results of our lead/lag study prepared consistently with 5 previous rate cases. The resulting Cash Working Capital amounts are as follows: 6 2022 Test Year: (\$152.4 million); 7 2023 Plan Year: (\$163.6 million); 8 2024 Plan Year: (\$179.1 million). 9 10 HAS THERE BEEN A CHANGE IN THE TEST-YEAR CASH WORKING CAPITAL Q. 11 AMOUNT SINCE THE 2016-2019 MYRP? 12 Yes. The 2022 test year Cash Working Capital balance of \$152.4 million 13 represents a \$41.3 million increase compared to the 2019 plan year in the 2016-14 2019 MYRP of \$111.1 million. 15 16 WHAT IS THE SOURCE OF THE CHANGE IN CASH WORKING CAPITAL? Q. 17 Α. The change in Cash Working Capital results in a corresponding decrease in 18 average rate base. This change is primarily due to the net changes in the average 19 expense lead and revenue lag days between the two periods. Average revenue 20 lag days decreased to 39.07 in 2022 from 41.58 in 2016, meaning the Company's 21 revenues are being collected on average 2.51 days faster in 2022 than in 2016. 22 Conversely, the Company's average expense lead days increased to 58.22 in 2022 23 from 56.34 in 2016, meaning that the Company's cash outlay for paying 24 expenses has been extended by an average of 1.88 days. The shorter time in 25 collection of revenues exceeded the slower disbursing of cash and has 26 decreased the cash working capital balance to be included in rate base.

1	Q.	WHAT IS THE SIGNIFICANCE OF NEGATIVE CASH WORKING CAPITAL?
2	Α.	A negative cash working capital balance indicates that overall revenue
3		collections occur sooner than the date when the associated costs of service are
4		paid. In other words, on average, more cash requirements are being provided
5		by customers and vendors. The negative cash working capital reduces rate base
6		to compensate customers for funds provided to meet cash working capital
7		requirements. It should be noted that changes in the revenues or expenses
8		could cause the cash working capital calculation to change. The Company will
9		update the 2022-2024 MYRP COSS accordingly through this proceeding.
10		
11		V. INCOME STATEMENT
12		
13	Q.	WHAT TOPICS WILL YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?
14	Α.	In this section, I will support the reasonableness of the Company's proposed
15		MYRP income statements. I begin by providing the overall income statement
16		calculations and identify their components, then walk through each of the
17		MYRP components of the income statements in turn.
18		
19	Q.	ARE THE COMPANY'S PROPOSED MYRP INCOME STATEMENTS REASONABLE
20		FOR DETERMINING FINAL RATES IN THIS PROCEEDING?
21	Α.	Yes. The proposed MYRP income statements for the Company's Minnesota
22		jurisdiction electric operations were developed using sound ratemaking
23		principles in a manner similar to prior Company electric rate cases.

PLEASE IDENTIFY THE MAJOR COMPONENTS OF THE PROJECTED INCOME Q. 1 STATEMENTS. 2 3 The following are the major components of the MYRP income statements: Α. 4 Revenues; 5 • Operating and Maintenance Expenses; 6 Depreciation Expense; 7 Taxes; 8 AFUDC; and 9 Interchange Agreement. 10 11 PLEASE DESCRIBE THE SCHEDULES TO YOUR TESTIMONY THAT ARE RELATED 12 TO THE INCOME STATEMENT. 13 Schedules 11a-11c, 2022-2024 Income Statement Adjustment Schedules, are 14 bridge schedules that show the unadjusted income statement, each proposed 15 income statement adjustment, and the resulting proposed income statement for 16 each year of the MYRP Forecast. Schedules 11a-11c also include the revenue 17 deficiency amount for each item included in this schedule. 18 19 Schedule 8, Comparison of Detailed Income Statement Components, provides 20 a detailed statement of the income statement components. Page 1 provides a 21 comparison of income statement components for the 2022 test year to the 2019 22 plan year used in our most recent rate case. Page 2 provides the income 23 statement components for the MYRP Forecast.

1		A. Revenues
2	Q.	HOW DOES THE COMPANY PRESENT ITS PROJECTED SALES FOR THE MYRP
3		FORECAST?
4	Α.	The MYRP sales volumes are supported by Mr. Goodenough. Mr.
5		Goodenough discusses the basis for the Company's sales forecasts, including
6		the use of normal weather to develop the Company's projected MYRP sales.
7		
8	Q.	Do retail operating revenues reflect the projected level of
9		UNBILLED SALES VOLUMES IN THE MYRP FORECAST?
10	Α.	Yes. As Mr. Goodenough explains, the projected level of unbilled sales is
11		incorporated into the retail sales forecast on a calendar-month basis. This
12		eliminates the need to reconcile billing-month sales to calendar-month sales by
13		recording unbilled revenues.
14		
15	Q.	HAVE YOU CONSIDERED OTHER OPERATING REVENUES AS AN OFFSET TO THE
16		RETAIL REVENUE REQUIREMENT?
17	Α.	Yes. The MYRP Forecast includes items such as revenues from sales to other
18		utilities, certain revenues from wholesale trading activities, wholesale
19		transmission revenues, and specific tariff charges, including service activation
20		fees, reconnection fees, and others. Other operating revenues also include
21		billings to NSPW under the Interchange Agreement. I discuss adjustments to
22		revenues in more detail in Section VII, Annual Adjustments to the MYRP.

Q. HAVE REVENUES AND EXPENSES ASSOCIATED WITH NSPM'S NON-REGULATED

1

2		BUSINESS ACTIVITIES BEEN EXCLUDED FROM THE MYRP COST OF SERVICE?
3	Α.	Yes. We have excluded the revenues and expenses associated with
4		Commission-approved non-regulated business activities (i.e. customer-owned
5		street lighting maintenance and Sherco steam sales to Liberty Paper) from the
6		MYRP cost of service. Because these activities are recorded in below-the-line
7		accounts, they were not included in the MYRP Forecast.
8		
9	Q.	How are revenues and expenses related to the MISO schedules
10		TREATED IN RATES?
11	A.	Both revenues and expenses related to the MISO schedules are included in the
12		determination of retail rates through either base rates, the FCA, or the TCR
13		Rider. Base rate recovery, for example, includes both the revenues received
14		from MISO and the expense billings from MISO for Schedules 1 (Scheduling,
15		System Control, and Dispatch Service) and 2 (Reactive Supply and Voltage).
16		The FCA, for example, includes Schedule 3 (Regulating Reserve). The TCR
17		Rider includes recovery of Schedule 26 (Network Upgrade from Transmission
18		Expansion Plan) and 26-A (Multi-Value Project Usage Rate) revenues and
19		expenses. The TCR Rider also includes, for capital projects not regionally
20		shared, an Open Access Transmission Tariff (OATT) Revenue Credit to
21		estimate the revenue that will be collected for the project from wholesale
22		transmission customers. The treatment of revenues and expenses related to the
23		MISO schedules is consistent with their treatment in prior rate cases.

1	Q.	WHAT ARE WHOLESALE MARGINS?
2	Α.	There are two categories of transactions that generate wholesale margins
3		(revenues less costs): asset based transactions; and non-asset based transactions
4		Asset based transactions are comprised of short-term sales of excess energy or
5		capacity from Company-owned generation assets or power purchase
6		agreements (PPAs) executed to serve our native load customers. The Company
7		executes these asset based transactions through bilateral agreements with
8		specific wholesale customers and through sales directly into the MISO energy
9		market. Sales into the MISO market account for the bulk of these transactions
10		
11		Non-asset based transactions are wholesale trading transactions undertaken to
12		obtain margins from purchases and sales of energy or capacity unrelated to
13		meeting the energy needs of our native load customers. The only transactions
14		that qualify as non-asset based transactions are third-party supplied electricity
15		or financial transactions that are not purchased to meet the needs of our retain
16		customers and that are then resold to other utilities or market participants.
17		
18	Q	HOW HAVE ASSET BASED MARGINS BEEN TREATED IN PRIOR RATE CASES?
19	Α.	Because asset based margins are created by selling energy or capacity from
20		generating facilities or PPAs paid for by customers, all asset based margins have
21		been credited to customers. In each of our last three rate cases, the Commission
22		approved passing the sales margins through to customers using the FCA.

1	Q.	IS THE COMPANY RECOMMENDING ANY CHANGE TO THE TREATMENT OF ASSET
2		BASED MARGINS?
3	Α.	No. The Company recommends the same treatment of crediting asset based
4		energy sales margins to customers through the FCA going forward.
5		
6	Q.	HOW HAVE NON-ASSET BASED MARGINS BEEN ADDRESSED IN PRIOR CASES?
7	Α.	In our last three rate cases: (i) 100 percent of the non-asset based trading
8		margins were retained by the Company; and (ii) 100 percent of the fully allocated
9		O&M costs and IT system-related costs associated with non-asset based trading
10		margins were excluded from the test year and, thus, resulted in a decrease in test
11		year operating expenses.
12		
13	Q.	IS THE COMPANY RECOMMENDING ANY CHANGE TO THE TREATMENT OF NON-
14		ASSET BASED MARGINS?
15	Α.	No. The Company recommends the same treatment of retaining 100 percent
16		of non-asset based trading margins and excluding 100 percent of the fully
17		allocated O&M and IT costs.
18		
19	Q.	HAS THE COMPANY CONDUCTED A FULLY ALLOCATED COST STUDY OF NON-
20		ASSET BASED TRADING?
21	Α.	Yes. The fully allocated O&M and IT cost study is included as
22		Exhibit(BCH-1) Schedule 17. The adjustment to remove the fully allocated
23		costs of non-asset based trading is included in Volume 4, Section VIII
24		Adjustments, Tab A17, Trading: Non-Asset Based Admin.

1	Q.	IS THE COMPANY RECOMMENDING ANY CHANGE TO NON-ASSET BASED STUDY?
2	Α.	Yes, since the study included in Schedule 17 is simply a comparison of the
3		incremental and fully allocated costs and this information is also provided in
4		Volume 4, Section VIII Adjustments, Tab A17, Trading: Non-Asset Based
5		Admin, the Company proposes to discontinue this study in future rate cases.
6		
7	Q.	Under the Company's proposals for asset based margins and non-
8		ASSET BASE MARGINS, IS IT NECESSARY TO MAKE ANY TEST OR PLAN YEAR
9		ADJUSTMENTS?
10	Α.	The treatment of asset-based and non-asset based margin as described above is
11		incorporated into the test and plan year base data. All asset-based energy
12		margins are shared with customers through the FCA and are excluded from
13		revenue and expenses in the 2022-2024 MYRP. Non-asset based margins are
14		retained by shareholders and are excluded from revenue and expense in the
15		2022-2024 MYRP. Lastly, the Non-Asset Trading O&M adjustment removes
16		the operating expenses in the income statement for the fully allocated O&M
17		and IT-related costs of non-asset based trading activity.
18		
19		B. Operating and Maintenance Expenses
20	Q.	HOW DOES THE COMPANY CALCULATE OPERATING EXPENSES?
21	Α.	The Company's operating expenses can be expressed using the breakdown on
22		Pages 30-31 of the "Electric Utility Cost Allocation Manual" of the National
23		Association of Regulatory Utility Commissioners (NARUC) as follows:

1			Operation and	d Maintenanc	e Expense (i	ncluding fue	l) (Operating Exp)
2		+	Depreciation 1	Expense (De _l	preciation)		
3		+	Miscellaneous	Amortization	n Expense (A	Amortization	1)
4		+	Taxes other th	nan Income T	axes (Other)	Taxes)	,
5			Income Taxes		,	,	
				•	•)		
6		_	Total Expense	es			
7							
8		In thi	s case, the calc	ulation is pro	vided in Tabl	le 6 below:	
9				7	Table (
10					Table 6		
11				Operati	ng Expense	es	
12				2022	2023	2024	Exhibit
13				Test Year	Plan Year	Plan Year	(BCH-1),
14				Amount	Amount	Amount	Sch. 3
14				(\$000s)	(\$000s)	(\$000s)	Reference
11			Item	(, ,	` ,	, ,	
15			Operating	\$ 2,427,130	\$ 2,469,029	\$ 2,487,435	Page 2, Line 74
		plus		, ,	, ,	\$ 2,487,435 899,980	Page 2, Line 74 Page 2, Line 76
15 16		plus plus	Operating Expense	\$ 2,427,130	\$ 2,469,029		
15 16 17		-	Operating Expense Depreciation	\$ 2,427,130 815,505	\$ 2,469,029 849,115	899,980	Page 2, Line 76
15 16		plus	Operating Expense Depreciation Amortization	\$ 2,427,130 815,505 61,229	\$ 2,469,029 849,115 55,267	899,980 54,647	Page 2, Line 76 Page 2, Line 77
15 16 17		plus plus	Operating Expense Depreciation Amortization Other Taxes	\$ 2,427,130 815,505 61,229 162,192	\$ 2,469,029 849,115 55,267 123,761	899,980 54,647 110,436	Page 2, Line 76 Page 2, Line 77 Page 2, Line 88
15 16 17 18		plus plus plus	Operating Expense Depreciation Amortization Other Taxes Income Tax	\$ 2,427,130 815,505 61,229 162,192 (97,637)	\$ 2,469,029 849,115 55,267 123,761 (85,432)	899,980 54,647 110,436 (89,624)	Page 2, Line 76 Page 2, Line 77 Page 2, Line 88 Page 3, Line 134
15 16 17 18 19	Q.	plus plus plus equals	Operating Expense Depreciation Amortization Other Taxes Income Tax	\$ 2,427,130 815,505 61,229 162,192 (97,637) \$ 3,368,419	\$ 2,469,029 849,115 55,267 123,761 (85,432) \$ 3,411,739	899,980 54,647 110,436 (89,624) \$ 3,462,874	Page 2, Line 76 Page 2, Line 77 Page 2, Line 88 Page 3, Line 134
15 16 17 18 19 20	Q. A.	plus plus plus equals	Operating Expense Depreciation Amortization Other Taxes Income Tax Total Expense	\$ 2,427,130 815,505 61,229 162,192 (97,637) \$ 3,368,419	\$ 2,469,029 849,115 55,267 123,761 (85,432) \$ 3,411,739 EXPENSE CA	899,980 54,647 110,436 (89,624) \$ 3,462,874	Page 2, Line 76 Page 2, Line 77 Page 2, Line 88 Page 3, Line 134
15 16 17 18 19 20 21	`	plus plus plus equals	Operating Expense Depreciation Amortization Other Taxes Income Tax Total Expense	\$ 2,427,130 815,505 61,229 162,192 (97,637) \$ 3,368,419 UCIPAL O&M se categories a	\$ 2,469,029 849,115 55,267 123,761 (85,432) \$ 3,411,739 EXPENSE CA	899,980 54,647 110,436 (89,624) \$ 3,462,874	Page 2, Line 76 Page 2, Line 77 Page 2, Line 88 Page 3, Line 134
15 16 17 18 19 20 21 22 23	`	plus plus plus equals	Operating Expense Depreciation Amortization Other Taxes Income Tax Total Expense T ARE THE PRIN	\$ 2,427,130 815,505 61,229 162,192 (97,637) \$ 3,368,419 ACIPAL O&M se categories a	\$ 2,469,029 849,115 55,267 123,761 (85,432) \$ 3,411,739 EXPENSE CA	899,980 54,647 110,436 (89,624) \$ 3,462,874	Page 2, Line 76 Page 2, Line 77 Page 2, Line 88 Page 3, Line 134
15 16 17 18 19 20 21 22 23 24	`	plus plus plus equals	Operating Expense Depreciation Amortization Other Taxes Income Tax Total Expense T ARE THE PRIN Orincipal expense Fuel & Purch	\$ 2,427,130 815,505 61,229 162,192 (97,637) \$ 3,368,419 UCIPAL O&M se categories a ased Energy; ction;	\$ 2,469,029 849,115 55,267 123,761 (85,432) \$ 3,411,739 EXPENSE CA	899,980 54,647 110,436 (89,624) \$ 3,462,874	Page 2, Line 76 Page 2, Line 77 Page 2, Line 88 Page 3, Line 134
15 16 17 18 19 20 21 22 23	`	plus plus plus equals	Operating Expense Depreciation Amortization Other Taxes Income Tax Total Expense T ARE THE PRIN	\$ 2,427,130 815,505 61,229 162,192 (97,637) \$ 3,368,419 ACIPAL O&M se categories a ased Energy; ction; kets;	\$ 2,469,029 849,115 55,267 123,761 (85,432) \$ 3,411,739 EXPENSE CA	899,980 54,647 110,436 (89,624) \$ 3,462,874	Page 2, Line 76 Page 2, Line 77 Page 2, Line 88 Page 3, Line 134

1		• Transmission;
2		• Distribution;
3		Customer Accounting;
4		Customer Service & Information;
5		Sales, Economic Development and Other; and
6		Administrative and General.
7		
8	Q.	How are Fuel and Purchased Energy costs treated?
9	Α.	The fuel and purchased energy costs are collected through the FCA. Those
10		costs are fully offset by revenues from the FCA or the Interchange Agreement,
11		as described in Section IX.A later in my Direct Testimony and confirmed by
12		the Deloitte & Touche, LLP (D&T) Report included as Exhibit(BCH-1)
13		Schedule 23. Therefore, these costs have no impact on the 2022-2024 MYRP
14		revenue deficiency.
15		
16	Q.	HAS THIS CHANGED SINCE THE 2016-2019 MYRP?
17	Α.	Yes. While the level of fuel revenues and expenses are consistent with the 2016-
18		2019 MYRP, the Company is no longer providing a base cost of energy filing
19		with this rate case, consistent with the Commission's November 5, 2019, Order
20		Approving Compliance Filings in Docket No. E999/CI-03-802. Consistent
21		with the Commission's Order, we have provided financial schedules that reflect
22		a cost of service with and without fuel revenues and expenses. Where
23		comparisons are made with prior years, we continue to present those financial
24		schedules with fuel revenues and expenses to allow comparison. Consistent
25		with the Commission's November 5, 2019, Order in Docket No. E999/CI-03-

802, and as discussed in greater detail later in my testimony, the rates proposed

1

exclude Fuel Clause Adjustment-related costs. 2 3 WHAT ARE POWER PRODUCTION COSTS AND HOW ARE THEY DETERMINED? Q. 4 Power production costs are primarily the costs of operating our generating 5 facilities. These costs are budgeted through development of a production 6 budget prepared to serve the combined energy and demand requirements of the 7 NSP System (used for both NSPM and NSPW). Please see the Direct 8 Testimony of Mr. Capra for further information related to how the Company 9 budgets for the operation and maintenance of our generation fleet. 10 11 HOW DOES XCEL ENERGY DEVELOP ITS TEST YEAR TRANSMISSION EXPENSE? Q. 12 Α. Transmission expenses are the O&M costs associated with operating and 13 maintaining our system transmission facilities. These costs are budgeted 14 through development of a transmission budget prepared to serve the NSP 15 System (i.e., for both NSPM and NSPW). These costs and their development 16 are detailed in Mr. Benson's Direct Testimony. 17 18 HOW DOES XCEL ENERGY DEVELOP ITS TEST YEAR DISTRIBUTION EXPENSE? Q. 19 Distribution expenses are the O&M costs associated with operating and 20 maintaining our Minnesota distribution facilities. These costs are developed 21 through a distribution budget that takes into account historical spend, known 22 changes to labor and non-labor inflationary factors, unique past and upcoming 23 projects and activities, and other identified cost considerations. These costs and 24 their development are detailed in the Direct Testimony of Ms. Bloch.

1	Q.	HOW DOES ACEL ENERGY DEVELOP ITS TEST YEAR CUSTOMER ACCOUNTING
2		EXPENSE?
3	A	Customer Accounting O&M cost is associated with providing meter reading,
4		billing, credit and collections, bad debt expense, contact center, and operational
5		support services. These costs are developed through the Customer Care budget
6		prepared for both the NSPM electric and gas utilities. These costs and their
7		development are detailed in the Direct Testimony of Company witness Mr.
8		Christopher C. Cardenas. The allocation of these costs to the electric utility and
9		then to the Minnesota jurisdiction is addressed in Section VI of my Direct
10		Testimony.
11		
12	Q.	What costs are included in Administrative and General (A&G)
13		EXPENSE?
14	Α.	A&G expense includes Information Technology (IT), compensation, office
15		supplies and expenses, and consulting services for officers, executives, and
16		other Company employees properly chargeable to utility operations and not
17		chargeable directly to a particular operating function. Also included in A&G
18		expense are insurance and other costs related to injury or damage claims made
19		by employees or others, employee pensions and benefits, regulatory expenses,
20		general advertising expense, utility rental expense not properly chargeable
21		directly to a particular operating function, and maintenance costs assignable to
22		the customer accounts, sales, and A&G functions.

Q. ARE ANY COSTS RELATED TO CIVIC OR POLITICAL ACTIVITIES (LOBBYING),

2		IDENTIFIED IN THE COST OF SERVICE, OR ADJUSTMENTS?
3	Α.	No. The Company records all lobbying costs to below-the-line accounting,
4		FERC account 426.4, Expenditures For Certain Civic, Political, and Related
5		Activities. The Company prepares the unadjusted expenses for the test year
6		using queries that restrict the data to only above-the-line accounts (FERC
7		Accounts 500 through 935). Thus, no adjustment to the cost of service for
8		lobbying costs is required, as these below-the-line amounts are not used in our
9		development of the test year cost of service. We have also excluded the portion
10		of organizational dues associated with lobbying activities. Company witness
11		Mr. William K. Husen addresses our efforts to identify and remove lobbying
12		expenses in his Direct Testimony.6
13		
14		C. Depreciation Expense
15	Q.	WHAT IS THE BASIS OF THE DEPRECIATION RATES AND EXPENSE USED IN THE
16		2022-2024 MYRP?
17	Α.	Depreciation expense for the 2022 test year base data reflects the Company's
18		depreciation rates last certified by the Commission for the 2020 Average

19

20

21

22

1

Remaining Life filing (Docket No. E, G002/D-19-723) and adjustments for the

pending 2020 Annual Update of Remaining Lives and Depreciation Rates for

Transmission, Distribution and General Accounts (Docket No. E, G002/D-21-

584). These adjustments are discussed in Section VII (adjustments 4 and 5).

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.

1		Mr. Moeller discusses the Company's depreciation expense in his Direct
2		Testimony.
3		
4		D. Taxes
5	Q.	What tax expenses are included in the 2022 test year income
6		STATEMENT?
7	Α.	We have line items for Property; Income Taxes including Deferred Income Tax,
8		Investment Tax Credits and Federal and State Income Tax; and Payroll. The
9		State and Federal income taxes are calculated in Schedule 3, Cost of Service
10		Study Summary for 2022 test year, Page 3 of 4.
11		
12	Q.	How are property taxes determined for the jurisdiction?
13	A.	Property taxes are determined on a NSPM Total Company basis. The functions
14		are then allocated to the Company's regulatory jurisdictions using the demand
15		allocator for electric production and transmission, the gas design day allocator
16		for gas production, gas transmission is direct assigned by state and distribution
17		is direct assigned by state for both electric and gas. Please see Volume 4, Section
18		III Rate Base (Plant), Tab P6, Property Tax for more details.
19		
20	Q.	How are income taxes determined for the jurisdiction?
21	Α.	Income taxes are determined based on total before tax book income, tax
22		additions, and deductions which determine deferred income taxes and the
23		resulting taxable income that is used to calculate federal and state income taxes.
24		The federal income tax rate reflects the 21 percent rate effective January 1, 2018
25		with the enactment of the TCJA. The utilization or generation of net operating

1		losses or tax credits impact both deferred income taxes and federal and state
2		income taxes, which I will discuss in more detail below.
3		
4	Q.	Does the cost of service reflect any potential federal or state
5		CORPORATE TAX RATE CHANGES DURING THE MYRP?
6	A.	Not at this time. When the cost of service was prepared, federal legislation
7		around a potential tax increase had been proposed, but the timing or the
8		effective date is still uncertain. In addition, any state or federal tax change
9		proposal would need to be passed into law before it would take effect.
10		
11	Q.	WHAT IMPACT WOULD A FEDERAL TAX RATE INCREASE HAVE ON THE COST OF
12		SERVICE?
13	Α.	The specific impacts to the cost of service would depend on the actual
14		legislation that is enacted, if any. However, at a high level, an increase in the
15		corporate income tax rate is expected to increase current and deferred income
16		tax expense and ADIT leading to a net increase in the cost of service. Similarly,
17		a decrease in the corporate income tax rate is expected to decrease current and
18		deferred income tax expense and ADIT leading to a net decrease in the cost of
19		service consistent with the TCJA impacts on the cost of service.
20		
21	Q.	WHAT DOES THE COMPANY PROPOSE IF INCOME TAX RATES WERE TO CHANGE
22		DURING THE MYRP?
23	Α.	At this time, it is not clear if or when federal and/or state tax rates may change,
24		but the Company would likely need to work with the Commission to seek relief
25		in such a change occurs. In the event of new tax legislation, it is also possible
26		other Minnesota utilities will need similar relief. One option may be to institute

1		a tracker, similar to how the TCJA was addressed in 2018, that would track and
2		defer the difference between the cost of service used to set final base rates in
3		this rate case filing with a cost of service adjusted for any income tax changes.
4		We would then address the net regulatory asset or liability in our next rate case.
5		
6	Q.	PLEASE SUMMARIZE THE RATEMAKING TREATMENT OF NET OPERATING
7		Losses (NOLs).
8	Α.	The Company continues to follow the resolution of "Tax Normalization and
9		Allowance for Net Operating Losses" from the last three rate cases, which was
10		reflected in Exhibit 105 in Docket No. E002/GR-10-971. Specifically, the
11		Company will continue to give back to retail customers annually the revenue
12		requirement benefit associated with the utilization of tax deductions and credits
13		carried forward from prior periods.
14		
15		NOLs require an adjustment that offsets the part of the ADIT rate base
16		reduction that is associated with the accelerated depreciation deductions that
17		have exceeded the Company's taxable income and have, thus, not resulted in
18		deferral of income taxes. That adjustment is needed to keep the Company's
19		rate base consistent with the income tax deductions that the Company has been
20		able to use. Keeping a balance of rate-base reductions resulting from the ADIT
21		and the use of accelerated depreciation deductions is required under federal
22		income tax law as part of "normalization" for both accounting and ratemaking.
23		
24		The timing of utilization and the carry-forward balances associated with unused
25		deductions and credits will continue to change over time as the Company's
26		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. The Company is not proposing any changes to that reporting process in this case.

Had this rate treatment not been approved by the Commission, the 2022 test

Had this rate treatment not been approved by the Commission, the 2022 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 protects customers in the event of changes in the utilization of tax deductions and credits, although the Company does not have the same protections if deferred tax assets increase between cases.

Q. Please explain how the Company determines whether deferred tax
 assets (DTAs) are created or consumed.

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. 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 Reports, including the (most recent) May 1, 2021 Jurisdictional Annual Report. Separate detailed reporting and the revenue requirement value associated with any utilization was most recently reported on June 1, 2021. By having these annual determinations made on an all-in basis, the jurisdictional cost of service study (JCOSS) includes actual data

1		for both rider recovery and base rate recovery. Any change in rider recovery by
2		the Commission will be incorporated in this process.
3		
4	Q.	DO THE DTAs AFFECT THE 2022-2024 MYRP REVENUE REQUIREMENTS?
5	Α.	Yes. The Company's 2022-2024 MYRP COSS includes a revenue requirement
6		increase associated with Production Tax Credits (PTCs) carried forward from
7		prior periods to the 2022 test year and 2022-2024 MYRP generation of federal
8		tax credits to be carried forward based on the Company's 2022-2024 MYRF
9		COSS. An accounting for the balances carried forward to the 2022 test year
10		COSS, as well as the documented calculations supporting this revenue
11		requirement increase, can be found in Exhibit(BCH-1), Schedule 20, Net
12		Operating Loss.
13		
14		It should be noted that any change in the revenues, expenses, or capital structure
15		will cause the income tax calculation to be changed. This could, in turn, affect
16		the timing of the DTAs being generated or consumed and added to or removed
17		from rate base. The Company will update the 2022-2024 MYRP COSS
18		accordingly.
19		
20	Q.	WHAT ARE PTCs?
21	Α.	PTCs are per-kWh tax credits to income for electricity generated using qualified
22		renewable energy resources

1	Q.	What is the level of PTCs included in the State and Federal income
2		TAX CALCULATION IN THE 2022 TEST YEAR?
3	Α.	As shown on Exhibit (BCH-1), Schedule 18, Production Tax Credits, the
4		MYRP Forecast assumes PTCs for the Company-owned wind farms as shown
5		in Table 7 below.
6		Table 7
7		Production Tax Credits included in MYRP Forecast
8		(Amount in \$000s) 2022 2023 2024
9		MN PTC Impact on Rev (\$190,169) (\$192,916) (\$193,385) Req net of I/A
10		
11		We expect production to begin at additional wind facilities in 2022. Due to the
12		anticipated in-service date of these projects, the Company is recommending that
13		these projects be recovered through the RES Rider. I provide a discussion later
14		in this Section of my Direct Testimony about how PTCs interact with the
15		deferred tax asset calculations in the 2022 test year.
16		
17	Q.	WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE TREATMENT OF
18		PTCs between test years?
19	Α.	In addition to the PTCs included in the RES Rider, the Company continues to
20		recommend that the RES Rider act as a true-up mechanism for the PTCs related
21		to projects already in service and included in base rates as a part of the 2022 test
22		year cost of service. We propose that the difference in the dollar value of actual
23		PTCs generated and the amounts included in the test year be recorded to the
24		RES Tracker account and either returned to, or recovered from, customers
25		through the RES Rider. This approach meets our understanding of the current
26		regulatory treatment for PTCs.

1	Q.	PLEASE EXPLAIN THE EFFECT OF TAX TREATMENT OF PTCs AND THE REQUIRED
2		REVENUE LEVEL NECESSARY TO COVER THE CHANGE IN OPERATING INCOME.
3	Α.	PTCs create a direct reduction (credit) to income tax expense causing a
4		corresponding increase to operating income. Every dollar change in operating
5		income needs a revenue conversion factor to be applied to determine the pre-
6		tax revenue level necessary to achieve the operating income change. The
7		revenue conversion factor calculation is included in Volume 3, Section II.7,
8		Required Financial Information, Other Supplemental Information, Tab B,
9		Gross Revenue Conversion Factor; and composite income tax rates are
10		included in Volume 3, Section II.4, Required Financial Information, Operating
11		Income Schedules, Tab C, Schedule C-5.
12		
13	Q.	WHAT IS THE REDUCTION IN REVENUE REQUIREMENTS FOR PTCs REFLECTED
14		IN THE 2022 TEST YEAR FINANCIAL STATEMENTS?
15	Α.	The State of Minnesota jurisdictional revenue requirement impact of PTCs in
16		the test year, after applying the 1.40335 revenue conversion factor, is (\$190.2
17		million) net of Interchange Agreement billings to NSPW. Support for these
18		calculations is shown on Schedule 18, Production Tax Credits.
19		
20		E. AFUDC
21	Q.	WHAT IS AFUDC, AND WHAT IS ITS FUNCTION IN THE INCOME STATEMENT?
22	Α.	As previously noted, AFUDC is the cost of financing during the period a capital
23		investment is included in CWIP. Once an asset is placed in service, the total
24		cost to construct including accumulated AFUDC is recovered through
25		depreciation expense. Mr. Moeller's Direct Testimony discusses the role
26		AFUDC plays in allowing utilities to recover their cost of financing. In the

1		income statement, AFUDC is used to offset expenses, thus increasing total
2		operating income, and reducing the revenue requirement. This provides a direct
3		offset to the return requirement associated with the inclusion of CWIP in rate
4		base. Please see Section IV. Rate Base, for a detailed discussion of the
5		relationship between CWIP and AFUDC and a discussion of Pre-Funded
6		AFUDC.
7		
8		F. Interchange Agreement
9	Q.	PLEASE DESCRIBE THE INTERCHANGE AGREEMENT BETWEEN THE COMPANY
10		AND NSPW.
11	Α.	The Company and NSPW operate a single integrated electric generation and
12		transmission system and a single electrical "local balancing authority area." This
13		integrated NSP System jointly serves the electric customers and loads of the
14		Company and NSPW. However, the specific generators and transmission
15		facilities making up the NSP System are owned by the two separate legal entities
16		(the Company and NSPW), with the ownership boundary at the
17		Minnesota/Wisconsin border. The Interchange Agreement is a FERC-
18		approved contractual mechanism that provides a means to share the costs of
19		the integrated NSP System between the Company and NSPW.
20		
21	Q.	PLEASE DESCRIBE THE COSTS AND REVENUES ALLOCATED BETWEEN THE
22		COMPANY AND NSPW UNDER THE INTERCHANGE AGREEMENT.
23	Α.	Under the Interchange Agreement, the Company and NSPW share annual
24		system generation (production) and transmission costs. Under the Interchange
25		Agreement formulas, approximately 16 percent of the costs of the Company
26		system are allocated to NSPW, and approximately 84 percent of the NSPW

1		system costs are allocated to the Company, because approximately 84 percent
2		of the load on the integrated system is the Company load and 16 percent is
3		NSPW load. The exact allocation percentages are determined by the allocation
4		factors updated and filed at FERC annually.
5		
6		The Interchange Agreement also provides for an allocation of revenues received
7		by the Company and NSPW, such as revenues from transmission services or
8		off-system wholesale sales. Interchange Agreement costs and revenues are
9		budgeted by the Company and NSPW annually. Thus, the Company's budget
10		shows Interchange Revenues, which are revenues that reflect the charges to
11		NSPW for its share of production and transmission assets and associated
12		expenses. Likewise, Interchange Expense reflects the Company's budgeted
13		payments to NSPW for its proportionate share of the costs of generation and
14		transmission assets and associated expenses incurred by NSPW to serve the
15		NSP System needs.
16		
17		The MYRP Forecast Interchange Revenue and Interchange Expenses have
18		been calculated using 2022-2024 Company and NSPW budget information.
19		This is consistent with the treatment of Interchange Revenues and Interchange
20		Expenses in our last three rate cases.
21		
22	Q.	Please describe the Interchange Agreement off-set treatment
23		BEING EMPLOYED IN THE MYRP FORECAST COSS.
24	Α.	As discussed earlier, in general, the Interchange Agreement is designed to share
25		system-related production and transmission cost between the two operating
26		companies, NSPM and NSPW. The intent of this sharing is to represent these

1		two company systems as a single joint operation. To equalize the costs across
2		this joint system, each operating company bills the other operating company for
3		their share of the joint costs in general using energy requirements as the basis
4		for sharing variable costs and peak demand as the basis for sharing capital
5		related and other fixed costs.
6		
7	Q.	What specific components are impacted by this sharing in the 2022-
8		2024 MYRP COSS?
9	Α.	The NSPM billings to NSPW for the sharing of NSPM costs appear as other
10		revenues in the MYRP Forecast cost of service. The NSPW billings to NSPM
11		for the sharing of NSPW costs appear as either production or transmission
12		expenses in the MYRP Forecast cost of service. Also, any adjustments being
13		proposed in the case that pertain to production or transmission are developed
14		using the same mechanics.
15		
16		VI. UTILITY AND JURISDICTIONAL ALLOCATIONS
17		
18	Q.	WHAT TOPICS DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?
19	Α.	In this section I will:
20		• explain, at a high level, why it is necessary for the Company to allocate
21		costs among its affiliates and between the jurisdictions in which it does
22		business;
23		• describe the utility and jurisdictional allocations that are used in
24		determining the revenue requirement;
25		• explain the circumstances of the elimination of the separate Wholesale
26		Jurisdiction, the circumstances that led to the loss of full-service

1		wholesale customers, and the effect of those events, including the results
2		of the Company's Wholesale Customer Study.
3		
4	Q.	Why is it necessary to assign or allocate costs between NSPM and its
5		AFFILIATES?
6	Α.	Whenever services or facilities are shared between NSPM and an affiliate, it is
7		necessary that the appropriate costs related to those services or facilities be
8		assigned or allocated to the appropriate entity. Company witness Mr. Ross L.
9		Baumgarten, in his Direct Testimony, explains the allocations for services and
10		facilities shared between NSPM and an affiliate. Additional information
11		regarding this process and the reason for selecting a particular allocator is also
12		included in the Cost Assignment and Allocation Manual (CAAM) submitted
13		with this application as Mr. Baumgarten's Exhibit(RLB-1), Schedule 3.
14		
15	Q.	Is it necessary to assign or allocate costs between NSPM's electric
16		AND GAS UTILITIES?
17	Α.	Yes. NSPM operates both an electric utility and a gas utility. Therefore, it is
18		necessary that the appropriate costs related to those services or facilities be
19		assigned or allocated to the appropriate utility.
20		
21	Q.	IS IT NECESSARY TO ASSIGN OR ALLOCATE COSTS BETWEEN JURISDICTIONS?
22	Α.	Yes. The Company operates in three jurisdictions: Minnesota, North Dakota,
23		and South Dakota. Thus, it is necessary to allocate or assign costs appropriately
24		between jurisdictions. Previously, costs were allocated or assigned to four
25		jurisdictions: Minnesota, North Dakota, South Dakota, and Wholesale.
26		Beginning in 2014, however, the Company has no full requirements wholesale

1		customers. Therefore, since 2014, costs are allocated between the Company's
2		three retail jurisdictions.
3		
4	Q.	HOW ARE COSTS ASSIGNED AND ALLOCATED?
5	Α.	The expense budgets relied upon to develop test-year income statement items
6		were generally prepared on a functional basis (i.e. Production, Transmission,
7		Distribution, Customer Accounts, Customer Information, Sales,
8		Administrative and General). These functional amounts are directly assigned
9		to the Minnesota jurisdiction electric utility operations where appropriate or
10		allocated based on cost causation.
11		
12		Detailed records are maintained on a functional basis (i.e. Production,
13		Transmission, Distribution, etc.). The capital budgets, from which the
14		projected plant balances in rate base were developed, are also prepared on a
15		functional basis. These functional amounts are assigned to the appropriate
16		jurisdiction directly or allocated based on the use of such assets in providing
17		electric service in a particular jurisdiction and the underlying elements of cost
18		causation.
19		
20		Generally, all production plant is allocated to jurisdiction using the jurisdictional
21		demand allocator, with the exception of wind projects, which are allocated using
22		the jurisdictional energy allocator. In addition, production costs are shared with
23		NSPW under the terms of the Interchange Agreement. The Interchange
24		Agreement tariff approved by FERC specifically requires fixed production
25		assets to be allocated between NSPM and NSPW based on demand.

1		Fixed production O&M expense is allocated using the jurisdictional demand
2		allocator. In addition, fixed production O&M expense is shared with NSPW
3		under the terms of the Interchange Agreement. The Interchange Agreement
4		requires these costs to be allocated between NSPM and NSPW based on
5		demand.
6		
7		All variable production O&M expense is allocated to jurisdiction using the
8		jurisdictional energy allocator. In addition, variable production O&M expense
9		is shared with NSPW under the terms of the Interchange Agreement. The
10		Interchange Agreement requires these costs to be allocated between NSPM and
11		NSPW based on energy.
12		
13		Mr. Baumgarten further explains assignment and allocation of costs in his
14		Direct Testimony.
15		
16	Q.	HOW ARE THESE ALLOCATION FACTORS DEVELOPED?
17	Α.	A summary and description of the allocation factors used to allocate expenses
18		and capital items to the Minnesota jurisdictional electric operations income
19		statement and rate base is contained in Volume 3, Section II.3, Required
20		Financial Information, Rate Base Schedules, Tab E Rate Base Jurisdictional
21		Allocation Factors, and Section II.4, Required Financial Information, Operating
22		Income Schedules, Tab F, Operating Income Jurisdictional Allocation Factors.
23		Plant investments are accounted for in the manner prescribed by the FERC
24		Uniform System of Accounts. Mr. Baumgarten also further explains the
25		development of allocation factors in his Direct Testimony.

- 1 Q. HOW ARE FUEL AND PURCHASED POWER COSTS ALLOCATED? 2 Fuel and purchased energy costs are allocated to each jurisdiction using the 3 jurisdictional energy allocator. Purchased demand costs are allocated to each 4 jurisdiction using the jurisdictional demand allocator. In addition, fuel and 5 purchased power costs are shared with NSPW under the terms of the 6 The Interchange Agreement requires fuel and Interchange Agreement. 7 purchased energy costs to be allocated between NSPM and NSPW based on 8 energy. Purchased demand costs are allocated between NSPM and NSPW using 9 demand. 10 11 WHAT IS THE WHOLESALE CUSTOMERS STUDY? Q. 12 The Wholesale Customers Study shows all wholesale customers being served Α. 13 by the Company (including, but not limited to, full requirements, partial 14 requirements, and market based wholesale customers), types of service being
- 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,

provided to each wholesale customer, costs, and revenues associated with each

for all services provided to wholesale customers.

19

15

- Q. Does the Wholesale Customers 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.

26

1	Q.	WHAT SERVICES DOES THE COMPANY ANTICIPATE PROVIDING TO PARTIAL
2		REQUIREMENTS WHOLESALE CUSTOMERS DURING THE MYRP FORECAST?
3	Α.	During the MYRP Forecast, the Company expects to provide services to
4		wholesale customers in the following categories: asset based energy sales, asset
5		based capacity sales, non-asset based energy and capacity sales, and other
6		wholesale transactions (including interfacing and scheduling services, energy
7		services agreements, and pass through charges).
8		
9		Services to wholesale customers include interfacing between the customer and
10		MISO, including providing balancing services. Revenues from these customers
11		for services and asset based capacity are included in Other Revenues (e.g., for
12		balancing services). Sales of asset based energy are treated as asset based margins
13		and passed through the fuel clause. We also provide some non-asset based
14		services to these customers (energy and capacity sales using financial instruments).
15		The margins from non-asset based transactions, as well as the fully allocated
16		embedded costs related those activities, are treated as below-the-line activities not
17		included in the retail revenue requirement.
18		
19		Attachment A to Schedule 14, Wholesale Customers Study provides a list of the
20		types of services provided, and the ratemaking treatment for each type of service.
21		Attachment B to Schedule 14, Wholesale Customers Study provides a wholesale
22		customer summary including all current agreements by customer and the expected
23		revenues for the years 2022 to 2024.

1	Q.	Does the Wholesale Customers Study demonstrate that the
2		REVENUES ARE INCLUDED IN THE RETAIL RATE CASE?
3	Α.	Yes. After reviewing the services provided to our wholesale customers and the
4		transactions associated with those services, the Company concludes that the
5		ratemaking treatment of these transactions is consistent with past regulatory
6		practice and the requirements of the Commission. Based on the treatment of
7		these transactions, the Company believes that costs and revenues associated
8		with wholesale customers are reflected properly in the test year.
9		
10		VII. ANNUAL ADJUSTMENTS TO THE MYRP
11		
12	Q.	WHAT TOPICS DO YOU ADDRESS IN THIS SECTION OF YOUR TESTIMONY?
13	Α.	In this section of my testimony, I explain adjustments that affect our proposed
14		MYRP Forecast revenue requirement. These adjustments were identified
15		during our review of the 2022 budget and preparation for this case. An
16		individual adjustment may be related to a previous Commission Order, reflect
17		Commission policy or traditional ratemaking treatment, or may be proposed to
18		address a situation particular to this rate case. In this section, I provide details
19		related to each adjustment and explain why each is necessary in order to present
20		a representative level of rate base or costs in the MYRP Forecast. I also identify
21		where another Company witness provides information to explain and support
22		the adjustment.
23		
24	Q.	HOW ARE THESE ADJUSTMENTS PRESENTED IN YOUR TESTIMONY?
25	Α.	First, I present traditional adjustments consistent with treatment in prior cases

26

and existing Commission Policy Statements (Precedential Adjustments) and rate

1		case adju	ustments specific to this particular case (Rate Case Adjustments). Next,
2		I explain	n the various amortizations affecting the test year (Amortizations), the
3		removal	of certain costs and revenues being recovered through riders (Rider
4		Remova	ls) and a group of adjustments that are the result of secondary dynamic
5		calculation	ons in the cost of service model (Secondary COS Calculations).
6			
7	Q.	PLEASE	LIST THE 2022-2024 MYRP ADJUSTMENTS.
8	Α.	The foll	lowing adjustments were made to rate base and the income statement
9		where a	pplicable. Rate base adjustments are shown on Schedules 10a-10c, Rate
10		Base A	adjustment Schedule. Income statement (revenue requirement)
11		adjustm	ents are shown on Schedules 11a-11c, 2022-2024 Income Statement
12		Adjustn	nent Schedule. As a general note, all revenue requirements shown on
13		Schedul	es 11a-11c, are net of Interchange Agreement billings, where applicable,
14		and cap	pital related revenue requirements are shown calculated at the last
15		authoriz	zed rate of return. Exhibit(BCH-1), Schedule 12 MYRP Adjustment
16		Summan	ry provides adjustment amounts for the MYRP, on this schedule capital
17		related	adjustments are shown calculated at the proposed rate of return.
18		Precede	ntial Adjustments are set forth in Exhibit (BCH-1), Schedule 13
19		and Tab	ole 8 below.
20			
21		Rate Ca	se Adjustments
22		1)	CIP Approved Program Costs
23		2)	Credit Card AutoPay
24		3)	Decommissioning
25		4)	Depreciation Study: Remaining Life
26		5)	Depreciation Study: TD&G

1	6)	Electric Battery Reserve Reallocation
2	7)	EOL Nuclear Fuel Update
3	8)	Incentive Compensation
4	9)	Nobles Amount over Certificate of Need
5	10)	Pension: Deferred Expense
6	11)	Pension: Discount Rate Expense
7	12)	Pension: Extend Deferral
8	13)	Pension: Retiree Medical Discount Rate
9	14)	Transmission ROE
10	<u>Amortiz</u>	<u>rations</u>
11	15)	Aurora Deferral
12	16)	BIS Rider
13	17)	State Credit Rate Change
14	18)	Income Tax Tracker Amortization
15	19)	LED Street Lighting Amortization
16	20)	NOL Tax Reform Regulatory Amortization
17	21)	Prairie Island EPU Deferred Costs
18	22)	Rate Case Expense
19	23)	Sherco 3 Depreciation
20	<u>Rider Re</u>	<u>emovals</u>
21	24)	Renewable Connect Removal and Avoided Capacity
22	25)	RES Rider
23	26)	TCR Rider
24	<u>Seconda</u>	ry Cost of Service Calculations
25	27)	ADIT Pro-Rate – IRS Required
26	28)	Cash Working Capital

- 1 29) Change in Cost of Capital
- 2 30) Net Operating Loss

3

4

A. Precedential Adjustments

- Q. Please list the precedential test year adjustments included in the
 Revenue requirement calculation.
- 7 A. Table 8 below is a list of Precedential Adjustments and their associated revenue 8 requirement impact, based on past rate case precedent and Commission policy:

9

10

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Table 8
Precedential Adjustments

12 13	Adjustment	2022 Test Year	2023 Plan Year	2024 Plan Year	Workpaper Reference
13	NSPM-Advertising (Trad)	(\$3,154)	(\$3,186)	(\$3,218)	WP-A1
14	NSPM-Assn Dues (Trad)	(36)	(37)	(37)	WP-A2
15	NSPM-Aviation	(2,041)	(2,455)	(2,798)	WP-A3
13	NSPM-Chamber of Commerce Dues	156	156	156	WP-A4
16	NSPM-Customer Deposits - A&G Expense (Trad)	7	7	7	WP-A5
17	NSPM-Donations (Trad)	584	1,685	1,686	WP-A6
17	NSPM-Econ Dev Donations (Trad)	102	102	102	WP-A7
18	NSPM-Econ Develop (Trad)	(229)	(229)	(229)	WP-A8
10	NSPM-Employee Expenses	(1,151)	(1,219)	(1,165)	WP-A9
19	NSPM-Foundation Admin	(150)	(152)	(154)	WP-A10
20	NSPM-Incentive Pay_Remove Long Term	(14,571)	(15,447)	(16,247)	WP-A11
21	NSPM-Investor Relations	(321)	(326)	(330)	WP-A12
21	NSPM-Monticello EPU Commission Order No Return	(9,089)	(7,835)	(6,632)	WP-A13
22	NSPM-Nuclear Retention Removal	(16)			WP-A14
22	NSPM-Pension Non-Qual Restoration Removal	(675)	(658)	(611)	WP-A15
23	NSPM-Pension Non-Qual SERP Removal	(213)	(156)	(144)	WP-A16
24	NSPM-Remove NonAsset Trading Fully Allocated Costs	(3,604)	(3,279)	(3,201)	WP-A17
25	Sub-Total Precedential	(\$34,401)	(\$33,030)	(\$32,814)	

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 completed 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
- 8 of each adjustment and supporting materials, in the workpapers identified in
- 9 Table 8 above. This organization is intended to facilitate the review of and full
- support for each adjustment within the identified workpaper.

11

1

Q.

- 12 Q. WHAT IMPACT DO THESE PRECEDENTIAL ADJUSTMENTS HAVE ON THE COMPANY'S ABILITY TO RECOVER ITS TOTAL COSTS OF SERVICE?
- A. Regulatory treatment of these precedential adjustments, combined with the incentive compensation adjustments discussed below, decrease our recovery of our costs of service by approximately \$26 to \$28 million as shown in Table 9 below. The Company expects to incur these costs over the three years of the MYRP, so the cumulative cost to the Company is \$81 million over the three-year MYRP.

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23

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Table 9 Regulatory Disallowances

Adjustment	2022 Test Year	2023 Plan Year	2024 Plan Year	Total
Total Precedential	(\$34,401)	(\$33,030)	(\$32,814)	(\$100,244)
Total Incentive Adjustments	6,126	6,374	6,671	19,171
Total Disallowances	(\$28,275)	(\$26,656)	(\$26,143)	(\$81,073)

2627

1	Q.	How is the Company incorporating these adjustments into the MYRP
2		FORECAST?
3	Α.	The precedential adjustments are combined in one column matching the Total
4		Precedential row in Table 8 above to Schedules 11a-11c, 2022-2024 Income
5		Statement Adjustment Schedule. In total, these precedential adjustments
6		represent a decrease in our rate request compared to our budgeted costs. The
7		detail of the precedential adjustments in bridge schedule format can be seen in
8		Schedule 13, Precedential Adjustment Detail. In addition, as noted above, each
9		respective workpaper referenced above contains a detailed description of the
10		adjustment, including the past precedent and related Commission Orders or
11		Policy Statements.
12		
13	Q.	WITH RESPECT TO ECONOMIC DEVELOPMENT COSTS, HAS THE COMPANY
14		PERFORMED A COST BENEFIT ANALYSIS TO DETERMINE THAT THE BENEFITS OF
15		THE ECONOMIC DEVELOPMENT PROGRAMS EXCEED THEIR COST TO RETAIL
16		CUSTOMERS?
17	Α.	Yes. We completed a cost-benefit analysis supporting the inclusion of
18		economic development costs in the MYRP Forecast. Exhibit(BCH-1),
19		Schedule 16, Economic Development Cost-Benefit Analysis, Attachments A
20		and B provide the potential revenue and cost impacts of the addition of one
21		commercial/industrial customer to NSPM's electric system due to economic
22		development programs. The results indicate that the investments made by the
23		Company to support economic development in our community have the
24		potential to provide value to customers as soon as the second year.

1		B. Rate Case Adjustments
2		1) CIP Approved Program Costs
3	Q.	PLEASE DESCRIBE THE CIP APPROVED PROGRAM LEVELS ADJUSTMENT.
4	Α.	The MYRP Forecast CIP expenses and corresponding revenues have been set
5		at the 2022 level of \$128.5 million as proposed in Docket E,G002/CIP-20-473.
6		
7		Because we make corresponding adjustments to both revenue and expense, this
8		adjustment has no impact on the MYRP Forecast deficiency, as shown on:
9		• Schedule 11, page 1, row 41, column 8;
10		• Schedule 12, page 1, row 22, columns 5 through 7;
11		• Volume 4, Section VIII Adjustments, Tab A18, CIP Approved
12		Program Levels.
13		
14		I note that the decision of the Deputy Commissioner of the Minnesota
15		Department of Commerce in Docket No. E,G002/CIP-20-473 on the
16		Company's 2022-2024 CIP Triennial Plan was not yet available as I prepared
17		this testimony. However, as previously noted, the decision would not affect the
18		revenue deficiency in this proceeding since any changes are made to both
19		revenue and expense.
20		
21		2) Credit Card AutoPay
22	Q.	PLEASE DESCRIBE THE CREDIT CARD AUTOPAY ADJUSTMENT.
23	Α.	The credit card autopay adjustment is a proposal the Company is making in the
24		2022-2024 MYRP to improve this payment option for customers and include
25		credit card processing costs in base rates rather than have customers continue
26		to be charged on a per-transaction basis. The Company's proposal also includes

1		a tracker for these costs, which I discuss in further detail in Section VIII, Costs
2		Recovered in Riders and Trackers, Part B. Trackers and Deferrals, of my Direct
3		Testimony. Mr. Cardenas also discusses the Company's proposal in his Direct
4		Testimony.
5		
6		This adjustment impacts the MYRP Forecast revenue requirements by the
7		amounts shown on:
8		• Schedule 11, page 1, row 41, column 9;
9		• Schedule 12, page 1, row 23, columns 5 through 7;
10 11		• Volume 4, Section VIII Adjustments, Tab A19, Credit Card Auto Pay.
12		3) Decommissioning
13	Q.	PLEASE DESCRIBE THE DECOMMISSIONING ADJUSTMENT.
14	A.	We have adjusted the 2022-2024 MYRP to reflect the most recently
15		recommended accrual level included in the open 2022-2024 Triennial Nuclear
16		Plant Decommissioning Study and Assumptions, Docket No. E002/M-20-855.
17		Support for this change is provided by Mr. Moeller in his Direct Testimony.
18		
19		This adjustment impacts the MYRP Forecast revenue requirements by the
20		amounts shown on:
21		• Schedule 11, page 1, row 41, column 10;
22		• Schedule 12, page 1, row 24, columns 5 through 7;
23		Volume 4, Section VIII Adjustments, Tab A20, MN Decommissioning.

1		4) Depreciation Study: Remaining Life
2	Q.	PLEASE DESCRIBE THE DEPRECIATION STUDY: REMAINING LIFE ADJUSTMENT.
3	A.	We have adjusted the 2022-2024 MYRP to include the approved changes of
4		Docket No. E,G002/D-19-723. The Commission's Order was issued on
5		September 2, 2021, after the base forecast was prepared; therefore it was
6		necessary to make an adjustment to reflect the approved changes. Support for
7		the changes that were approved are provided by Mr. Moeller in his Direct
8		Testimony.
9		
10		This adjustment impacts the MYRP Forecast revenue requirements by the
11		amounts shown on:
12		• Schedule 10, page 1, row 43, column 7;
13		• Schedule 11, page 1, row 41, column 11;
14		• Schedule 12, page 1, row 25, columns 5 through 7;
15		• Volume 4, Section VIII Adjustments, Tab A21, Depreciation Study:
16		Remaining Life.
17		
18		5) Depreciation Study: TD&G
19	Q.	PLEASE DESCRIBE THE DEPRECIATION STUDY: TD&G ADJUSTMENT.
20	Α.	We have adjusted the 2022-2024 MYRP to include the impact of Docket No.
21		E,G002/D-21-584. The new depreciation rates as proposed in the compliance
22		filing would increase total Company depreciation expense by \$0.7 million. We
23		have proposed the new rates to be effective as of January 1, 2022. The 2021
24		docket is still pending final approval. However, the Test Year calculations
25		assume that this filing will be adopted in its entirety. To the extent that these
26		are not adopted per the filing, the Company will submit updates in rebuttal

1		testimony. Support for these changes are provided by Mr. Moeller in his Direct
2		Testimony.
3		
4		This adjustment increases MYRP Forecast revenue requirements by the
5		amounts shown on:
6		• Schedule 10, page 1, row 43, column 8;
7		• Schedule 11, page 1, row 41, column 12;
8		• Schedule 12, page 1, row 26, columns 5 through 7;
9		• Volume 4, Section VIII Adjustments, Tab A22, Depreciation Study:
10		TD&G.
11		
12		6) Electric Battery Reserve Reallocation
13	Q.	Please describe the electric battery reserve reallocation
14		ADJUSTMENT.
15	Α.	We have adjusted the 2022-2024 MYRP to include the impact of Docket No.
16		E,G002/D-19-723. In the 2020 Remaining Lives filing, we proposed
17		modifications to the remaining life of the Luverne Wind2Battery System and
18		reserve reallocations to certain Other Production accounts. These proposals
19		were not adopted in the Remaining Lives docket. The issue of the reserve
20		reallocation was deferred to this proceeding. Support for the changes to
21		depreciation expense for the proposed \$5.6M Luverne Battery removal cost
22		reserve allocation as of January 2022 is provided by Mr. Capra and Mr. Moeller
23		in their Direct Testimony. The impact to depreciation expense caused by this
24		reallocation has been excluded from interim rates as ordered in the remaining
25		lives docket.

26

1		This adjustment impacts the MYRP Forecast revenue requirements by the
2		amounts shown on:
3		• Schedule 10, page 1, row 43, column 9;
4		• Schedule 11, page 1, row 41, column 13;
5		• Schedule 12, page 1, row 27, columns 5 through 7;
6		• Volume 4, Section VIII Adjustments, Tab A23, Electric Battery
7		Reserve Reallocation.
8		
9		7) End of Life (EOL) Nuclear Fuel Update
10	Q.	PLEASE DESCRIBE THE EOL NUCLEAR FUEL UPDATE ADJUSTMENT.
11	A.	The EOL Nuclear Fuel adjustment reflects a change in nuclear fuel expense for
12		nuclear fuel commodities associated with the last few reloads at each
13		unit. These revised cost estimates were the result of the Company's updated
14		study that revised the cost of the unburned nuclear fuel at the time of shutdown
15		of our nuclear generating plants. Support for this change is provided by Mr.
16		Moeller in his Direct Testimony.
17		
18		This adjustment impacts the MYRP Forecast revenue requirements by the
19		amounts shown on:
20		• Schedule 10, page 1, row 43, column 10;
21		• Schedule 11, page 1, row 41, column 14;
22		• Schedule 12, page 1, row 28, columns 5 through 7;
23		• Volume 4, Section VIII Adjustments, Tab A24, EOL Nuclear Fuel
24		Update.

1		8) Incentive Compensation
2	Q.	PLEASE DESCRIBE THE INCENTIVE COMPENSATION ADJUSTMENT.
3	Α.	We have adjusted MYRP Forecast costs to include the budgeted costs for the
4		long-term incentive (LTI) compensation related to Company achievement of
5		environmental goals and time-based employee retention incentives and exclude
6		the budgeted costs for: 1) any non-corporate incentive plan costs; and 2) all
7		Annual Incentive Plan amounts above 20 percent of each individual's base pay.
8		Company witness Ms. Ruth K. Lowenthal discusses incentive compensation in
9		her Direct Testimony.
10		
11		This adjustment decreases MYRP Forecast revenue requirements by the
12		amounts shown on:
13		• Schedule 11, page 1, row 41, column 15;
14		• Schedule 12, page 1, row 29-31, columns 5 through 7;
15		• Volume 4, Section VIII Adjustments, Tabs A25, AIP over Cap, A26,
16		Environmental LTI, and A27 Time Based LTI.
17		
18		9) Nobles Amount over Certificate of Need
19	Q.	PLEASE DESCRIBE THE NOBLES DISALLOWED ASSET ADJUSTMENT.
20	A.	The Commission's Order in Docket No. E002/GR-12-961 required the
21		Company to amortize costs related to the Nobles Wind plant above the amount
22		estimated in the Company's Certificate of Need filing over the remaining life of
23		the plant. Specifically, the Commission ordered that the amortization includes
24		a return of, but not a return on, the \$5.6 million (IA) jurisdictional cost. To
25		accomplish this, the Company continues to include all cost components in base
26		data, such as net investment in rate base and depreciation expense in the income

1		statement. To value the zero return on rate base, a rate base return revenue
2		requirement calculation is performed and included as other revenue to reduce
3		the deficiency for this return requirement. This adjustment is included in the
4		2022 test year consistent with our last rate case. In Docket No. E-002/M-20-
5		620, the Commission approved the Company's proposal to repower the Nobles
6		facility; therefore, this adjustment is no longer needed as of the repower date.
7		
8		This adjustment impacts the MYRP Forecast revenue requirements by the
9		amounts shown on:
10		• Schedule 11, page 1, row 41, column 16;
11		• Schedule 12, page 1, row 32, columns 5 through 7;
12		• Volume 4, Section VIII Adjustments, Tab A28, Nobles Amounts over
13		CON.
14		
15		10) Deferred Pension Expense
16	Q.	PLEASE DESCRIBE THE DEFERRED PENSION EXPENSE ADJUSTMENT.
17	Α.	This adjustment reflects the annual amount of the three-year amortization of
18		the XES Plan cap cumulative deferred balance. The cumulative deferred
19		balance is discussed by Company witness Mr. Richard R. Schrubbe.
20		
21		This adjustment impacts MYRP Forecast revenue requirements by the amounts
22		shown on:
23		• Schedule 11, page 1, row 41, column 17;
24		• Schedule 12, page 1, row 33, columns 5 through 7;
25		• Volume 4, Section VIII Adjustments, Tab A29, Pension: Deferred
26		Amortization.

1		11) Pension Discount Rate Expense
2	Q.	PLEASE DESCRIBE THE PENSION DISCOUNT RATE EXPENSE ADJUSTMENT.
3	Α.	This adjustment reflects the Company's recalculation of its MYRP Forecast
4		pension costs using a five-year average discount rate. The Company determined
5		the five-year rolling average discount rate consistent with Order Point 7 in
6		Docket No. E002/GR-13-868. Mr. Schrubbe discusses the pension discount
7		rate in his Direct Testimony.
8		
9		This adjustment impacts MYRP Forecast revenue requirements by the amounts
10		shown on:
11		• Schedule 11, page 1, row 41, column 18,
12		• Schedule 12, page 1, row 34, columns 5 through 7,
13		• Volume 4, Section VIII Adjustments, Tab A30, Pension: Discount
14		Rate.
15		
16		12) Pension Extend Deferral
17	Q.	PLEASE DESCRIBE THE PENSION EXTEND DEFERRAL ADJUSTMENT.
18	Α.	This adjustment reflects the Company's deferred pension expense difference
19		related to extending the amortization period for unrecognized pension costs for
20		the NSPM Plan from 10 to 20 years, and a "cap and defer" recovery of XES
21		pension costs as approved in Docket No. E002/GR-13-868. Mr. Schrubbe
22		discusses the pension extend deferral further in his Direct Testimony.
23		
24		This adjustment impacts MYRP Forecast revenue requirements by the amounts
25		shown on:
26		• Schedule 10, page 1, row 43, column 11;

1		• Schedule 11, page 1, row 41, column 19;
2		• Schedule 12, page 1, row 35, columns 5 through 7;
3		• Volume 4, Section VIII Adjustments, Tab A31, Pension: Extend
4		Deferral.
5		
6		13) Pension Retiree Medical Discount Rate
7	Q.	PLEASE DESCRIBE THE PENSION RETIREE MEDICAL DISCOUNT RATE
8		ADJUSTMENT.
9	Α.	The Commission's Order in Docket No. E002/GR-13-868 states the discount
10		rate used to calculate retiree medical benefit costs for ratemaking purposes shall
11		be set to equal the five-year average of the FAS 106-based discount rates. Ar
12		adjustment is necessary to reflect the use of the five-year average discount rate
13		to calculate retiree medical benefits and reflect the appropriate expense level in
14		the test year. Mr. Schrubbe discusses retiree medical benefits and the discount
15		rate in his Direct Testimony.
16		
17		This adjustment impacts MYRP Forecast revenue requirements by the amounts
18		shown on:
19		• Schedule 11, page 1, row 41, column 20,
20		• Schedule 12, page 1, row 36, columns 5 through 7,
21		• Volume 4, Section VIII Adjustments, Tab A32, Pension: Retiree
22		Medical Adjustment.

1		14) Transmission ROE
2	Q.	PLEASE DESCRIBE THE TRANSMISSION ROE ADJUSTMENT.
3	Α.	In his Direct Testimony, Mr. Benson describes the MISO ROE complaints and
4		the potential test year impact on transmission revenues and expenses of any
5		final decision from FERC related to MISO ROE Complaints. The Company
6		believes a determination at FERC on this matter should not impact the retail
7		jurisdiction, and the cost of capital should be treated consistently across our rate
8		base; therefore, we are proposing this adjustment to calculate the net
9		transmission revenue credit using the ROE approved by the Commission in this
10		case. For purposes of this filing, the adjustment was prepared based on the last
11		authorized ROE of 9.06 percent for the TCR Rider. ⁷ In final compliance, the
12		Company will make an adjustment to reflect the final authorized ROE in this
13		case.
14		
15		This adjustment includes the impact on Attachment O, GG and MM from the
16		MISO Transmission Formula Rate which will be partially offset in the TCR
17		Rider removal of MISO RECB revenue and expenses discussed in Sections VII
18		and VIII of my testimony. This adjustment impacts the MYRP Forecast
19		revenue requirements by the amounts shown on:
20		• Schedule 11, page 1, row 41, column 21,
21		• Schedule 12, page 1, row 37, columns 5 through 7,
22		• Volume 4, Section VIII Adjustments, Tab A33, Transmission ROE.

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

Docket No. E002/GR-21-630 Halama Direct

1		C. Amortizations
2		15) Aurora Deferral
3	Q.	PLEASE DESCRIBE THE AURORA DEFERRAL EXPENSE AMORTIZATION.
4	Α.	The Commission's Order in Docket No. E-002/M-15-330 approved the PPA
5		between Xcel Energy and Aurora Distributed Solar, LLC. This resource was
6		disputed by the South Dakota Public Utilities Commission (SDPUC) in Docket
7		EL16-037 and resulted in recovery limited to an energy proxy price (derived
8		from the system average cost of fuel and purchased power), with no capacity
9		component. The Company is, therefore, requesting authorization to recover
10		the difference between the contracted PPA and the proxy price through this
11		case. Mr. Chamberlain discusses this request in his Direct Testimony. We are
12		requesting recovery of these costs over the two-year period from 2022-2023
13		along with the ability to pass this cost to Minnesota customers through the FCA
14		on a going forward basis beginning January 1, 2024.
15		
16	Q.	Please describe how the Aurora Deferral Expense amortization
17		ADJUSTMENT WAS CALCULATED.
18	Α.	This adjustment reflects actual PPA costs through June 30, 2021 and budgeted
19		PPA costs through December 31, 2023 in excess of the energy proxy price
20		referenced above from January 1, 2017, the date the South Dakota Public
21		Utilities Commission denied recovery, to January 1, 2024, the date the Company
22		requests to shift recovery to the FCA. The total accumulated balance over the
23		seven years is then amortized over 24 months.
24		
25		This adjustment impacts the MYRP Forecast revenue requirements by the
26		amounts shown on:

1		• Schedule 10, page 1, row 43, column 12;
2		• Schedule 11, page 2, row 41, column 22;
3		• Schedule 12, page 1, row 40, columns 5 through 7;
4		• Volume 4, Section VIII Adjustments, Tab A34, Aurora Deferral.
5		
6		16) BIS Rider
7	Q.	PLEASE DESCRIBE THE BIS RIDER AMORTIZATION.
8	Α.	The Commission's Order in Docket No. E002/M-20-436 and E002/M-20-662
9		approved temporary discount programs related to the pandemic and/or civil
10		unrest. The Company is, therefore, requesting authorization to recover the
11		deferral of these program costs over the MYRP Forecast.
12		This adjustment impacts the MYRP Forecast revenue requirements by the
13		amounts shown on:
14		• Schedule 10, page 1, row 43, column 13;
15		• Schedule 11, page 2, row 41, column 23;
16		• Schedule 12, page 1, row 41, columns 5 through 7;
17		• Volume 4, Section VIII Adjustments, Tab A35, BIS Rider.
18		
19		17) State Credit Rate Change
20	Q.	PLEASE DESCRIBE THE STATE CREDIT RATE CHANGE AMORTIZATION.
21	Α.	The state credits adjustment is needed to adjust the state tax credits on the 2017
22		tax return for the change in federal tax rate from 35 percent to 21 percent. This
23		amount was not reflected in the TCJA docket because it was not known until
24		the tax return was filed, so an estimate was used. This adjustment represents an
25		amount due to customers and therefore is a reduction to the revenue deficiency

1		This adjustment impacts the MYRP Forecast revenue requirements by the
2		amounts shown on:
3		• Schedule 10, page 1, row 43, column 14;
4		• Schedule 11, page 2, row 41, column 24;
5		• Schedule 12, page 1, row 42, columns 5 through 7;
6		• Volume 4, Section VIII Adjustments, Tab A36, State Credit Rate
7		Change.
8		
9		18) Income Tax Tracker Amortization
10	Q.	PLEASE DESCRIBE THE INCOME TAX TRACKER AMORTIZATION.
11	Α.	The Company has concluded tax audits with the IRS and the Minnesota
12		Department of Revenue for tax years ended 2010 through 2016. As a result of
13		the audits, the Company paid tax and interest on the disputed amounts. In the
14		Company's 1992 rate case, Docket No. E002/GR-92-1185, and in Docket Nos.
15		E002/M-93-1328, E002/M-04-1605, E002/M-05-1471 and E002/GR-12-961,
16		the Commission authorized deferred accounting status of both tax credits and
17		debits. Consistent with this precedent, we propose to collect this amount over
18		the MYRP period.
19		
20		This adjustment impacts the MYRP Forecast revenue requirements by the
21		amounts shown on:
22		• Schedule 10, page 1, row 43, column 15;
23		• Schedule 11, page 2, row 41, column 25;
24		• Schedule 12, page 1, row 43, columns 5 through 7;
25		• Volume 4, Section VIII Adjustments, Tab A37, Income Tax Tracker.

1		19) LED Street Lighting Amortization
2	Q.	PLEASE DESCRIBE THE LED STREET LIGHTING AMORTIZATION.
3	Α.	The Commission's Order in Docket No. E002/GR-15-826 approved deferral
4		of the LED Street Lighting revenue requirements, and the Commission's
5		Orders in Docket No. E002/19-688 (Order Approving True-Ups) and Docket
6		No. E002/20-723 (Stay Out Proposal) approved that deferral to continue for
7		an additional two years. The Company is, therefore, requesting authorization
8		to recover the LED Street Lighting costs over the MYRP Forecast.
9		
10		This adjustment impacts the MYRP Forecast revenue requirements by the
11		amounts shown on:
12		• Schedule 10, page 1, row 43, column 16;
13		• Schedule 11, page 2, row 41, column 26;
14		• Schedule 12, page 1, row 44, columns 5 through 7;
15		• Volume 4, Section VIII Adjustments, Tab A38, LED Street Lighting.
16		
17		20) NOL Tax Reform Regulatory Amortization
18	Q.	PLEASE DESCRIBE THE NOL TAX REFORM REGULATORY AMORTIZATION.
19	Α.	The Commission's Order in Docket No. E,G999/CI-17-895 approved the
20		Company's proposed amortization level included in the TCJA refund
21		calculation. This is being amortized over 23 years.
22		
23		The adjustment impacts the MYRP Forecast revenue requirements by the
24		amounts shown on:
25		• Schedule 10, page 1, row 43, column 17;
26		• Schedule 11, page 2, row 41, column 27;

1		• Schedule 12, page 1, row 45, columns 5 through 7;		
2		• Volume 4, Section VIII Adjustments, Tab A39, NOL Tax Reform		
3		ADIT ARAM.		
4				
5		21) Prairie Island EPU Deferred Costs		
6	Q.	PLEASE EXPLAIN THE ADJUSTMENT NEEDED TO RECOVER THE PRAIRIE		
7		ISLAND EXTENDED POWER UPRATE (EPU) DEFERRED COSTS.		
8	Α.	The Commission's Order in Docket No. E002/GR-13-868 approved the		
9		recovery of the abandoned Prairie Island EPU project costs over the remaining		
10		life of the plant through an amortization expense. The Order also approved		
11		including this unrecovered investment in rate base but limited the return on rate		
12		base related to this project to the weighted cost of debt.		
13				
14		The amortization and rate of return adjustment impacts the MYRP Forecast		
15		revenue requirements by the amounts shown on:		
16		• Schedule 10, page 1, row 43, column 18;		
17		• Schedule 11, page 2, row 41, column 28;		
18		• Schedule 12, page 1, row 46, columns 5 through 7;		
19		• Volume 4, Section VIII Adjustments, Tab A40, PI EPU Recovery.		
20				
21	Q.	PLEASE DESCRIBE THE PRAIRIE ISLAND EPU ADJUSTMENTS INCLUDED IN THE		
22		2022-2024 MYRP COSS IN MORE DETAIL.		
23	Α.	First, the various rate base and income statement components related to the		
24		amortization of this deferred cost are input as an adjustment to the cost of		
25		service. This results in the calculation of the overall revenue requirement		
26		associated with this project. Embedded in these calculations is a computation		

1		of return on rate base at the overall weighted cost of capital (debt and equity).
2		To adjust for the ordered weighted cost of debt return requirement, the
		,
3		Company computes the revenue requirements associated with the weighted cost
4		of equity and includes the result of this calculation as Other Revenues to reduce
5		the deficiency by this amount. If return component weighted costs are adjusted
6		during this case, this adjustment will require a recalculation to reflect those
7		changes.
8		
9		22) Rate Case Expense
10	Q.	PLEASE DESCRIBE THE RATE CASE EXPENSE AMORTIZATION.
11	Α.	The Company is requesting authorization to recover a total of \$4.686 million in
12		rate case costs over the MYRP Forecast. We are requesting recovery of these
13		costs over the three-year period 2022-2024, consistent with our multi-year rate
14		plan.
15		
16	Q.	PLEASE DESCRIBE HOW RATE CASE EXPENSE WAS ESTIMATED.
17	A.	The rate case expense budget was developed by first reviewing actual expenses
18		incurred in our 2015 electric rate case. We built the 2022 rate case budget based
19		upon a combination of our plans for outside experts, expected regulatory and
20		legal fees, and estimates for administrative costs such as required notices.
21		
22	Q.	HOW IS THIS ADJUSTMENT IMPACTING THE MYRP FORECAST REVENUE
23		REQUIREMENTS?
24	Α.	This adjustment impacts the MYRP Forecast revenue requirements by the
25		amounts shown on:
26		• Schedule 11, page 2, row 41, column 29;

1		• Schedule 12, page 1, row 47, columns 5 through 7;			
2		• Volume 4, Section VIII Adjustments, Tab A41, Rate Case Expenses.			
3					
4		23) Sherco 3 Depreciation			
5	Q.	PLEASE DESCRIBE THE SHERCO 3 DEPRECIATION DEFERRAL AMORTIZATION.			
6	Α.	The Commission's Order in Docket No. E002/GR-12-961 required the			
7		Company to defer the depreciation expense incurred for Sherco 3 during the			
8		extended repair outage following the 2011 catastrophic event and amortize it			
9		over the remaining life of the plant.			
10					
11		The adjustment impacts the MYRP Forecast revenue requirements by the			
12		amounts shown on:			
13		• Schedule 10, page 1, row 43, column 19;			
14		• Schedule 11, page 2, row 41, column 30;			
15		• Schedule 12, page 1, row 48, columns 5 through 7;			
16		Volume 4, Section VIII Adjustments, Tab A42, Sherco 3 Depr Deferral.			
17					
18		D. Rider Removals			
19	Q.	PLEASE DESCRIBE THE PURPOSE OF THE RIDER REMOVALS.			
20	Α.	As previously noted, the Company is removing from base rates all costs it is			
21		continuing to recover through riders. Rider costs removed from base rates			
22		include costs for rider-eligible projects that are ongoing after the conclusion of			
23		the test year; certain types of variable costs; and costs for certain ongoing rider			
24		programs. Conversely, some portions of rider-eligible projects - such as			
25		internal labor – remain in base rates because the Commission does not consider			
26		those project components to be rider-eligible. The discussion below			

1		demonstrates that the Company is appropriately removing rider costs from base
2		rates.
3		
4	Q.	FOR RIDER-ELIGIBLE PROJECTS WITH AN INTERNAL LABOR COMPONENT, HOW
5		DOES THE COMPANY CALCULATE THE INTERNAL LABOR COMPONENT THAT
6		WILL REMAIN IN BASE RATES?
7	Α.	The Company determines the percentage of total CWIP expenditures on a
8		project to date that consists of internal labor and applies that percentage to the
9		forecasted CWIP expenditures. From an O&M perspective, the Company
10		reviews the budget data and identifies the internal labor cost types. The rider
11		removal adjustment excludes these components from project costs, thereby
12		leaving the internal labor in base rates.
13		
14		24) Renewable*Connect Removal and Avoided Capacity
15	Q.	PLEASE DESCRIBE THE RENEWABLE*CONNECT REMOVAL AND AVOIDED
16		CAPACITY ADJUSTMENT.
17	Α.	The Renewable*Connect program is a stand-alone retail service program with
18		discrete revenues, purchase power contracts, and operating expenses. We have
19		excluded Renewable*Connect revenues and associated expenses from our
20		MYRP Forecast revenue requirements determination.
21		
22		Renewable*Connect is a voluntary renewable energy program that gives
23		customers an option to purchase renewable energy to meet all of their energy
24		needs. Customers can choose to subscribe to a five- or ten-year term, or on a
25		month-to-month basis. A customer subscribing to Renewable*Connect is

1		charged the Renewable*Connect price in lieu of the fuel clause pricing, which
2		is based on the Company's current mix of energy resources.
3		
4		Including Renewable*Connect as part of a utility's resource mix means that the
5		utility avoided building or purchasing from other sources. The kWh cost of
6		renewable energy purchased by a utility includes a capacity factor or value which
7		would otherwise have been included in the utility's base rates and paid by all
8		customers because all customers benefit from the capacity. This capacity credit
9		is subtracted from the Renewable*Connect rate because it is a cost that should
10		be shared by all customers, rather than only by Renewable*Connect customers.
11		The Direct Testimony of Company witness Mr. Michael A. Peppin further
12		supports the development of the Renewable*Connect avoided capacity credit.
13		
14		The net of these adjustments impacts the MYRP Forecast revenue requirements
15		by the amounts shown on:
16		• Schedule 11, page 2, row 41, column 31;
17		• Schedule 12, page 1, row 51, columns 5 through 7;
18		• Volume 4, Section VIII Adjustments, Tab A43, Renewable Connect.
19		
20		25) RES Rider
21	Q.	IS THE COMPANY PROPOSING CONTINUED USE OF THE RES RIDER DURING THE
22		MYRP?
23	Α.	Yes. As I describe in detail in Section VIII, Costs Recovered in Riders, we
24		propose continued use of the RES Rider during the MYRP for the projects that
25		will not be placed in-service as of December 31, 2021.

1	Q.	PLEASE DESCRIBE THE RES RIDER REMOVAL ADJUSTMENT.
2	Α.	The RES Rider removal adjustment removes all costs and PTCs from the test
3		year jurisdictional cost of service for the projects that we propose will stay in
4		the rider after the implementation of final rates in this case. The RES Rider test
5		year adjustment ensures no double recovery of these costs.
6		
7		For PTCs related to energy production at other Company-owned wind farms
8		currently and proposed to be included in base rates, we propose to continue the
9		true-up to actual PTCs in the RES Rider. These wind farms include Pleasant
10		Valley Wind Farm, Borders Wind Farm, Courtenay Wind Farm, Blazing Star I
11		Wind Farm, Foxtail Wind Farm, Lake Benton Wind Farm, Blazing Star II Wind
12		Farm, Crowned Ridge Wind Farm, Jeffers Wind Farm, Community Wind North
13		Wind Farm, Mower Wind Farm, Freeborn Wind Farm and Dakota Range Wind
14		Farm. Finally, should the Company sell any Renewable Energy Credits (RECs)
15		the proceeds from those sales would be shared with customers through the RES
16		Rider.
17		
18	Q.	WHAT COSTS ARE INCLUDED IN THE RES RATE RIDER REMOVAL ADJUSTMENT?
19	Α.	This adjustment includes project costs and PTCs for the incremental costs
20		associated with the four wind repower projects (Grand Meadow Wind Farm
21		Nobles Wind Farm, Pleasant Valley Wind Farm and Borders Wind Farm) and
22		Northern Wind Farm, as well as the proposed Sherco Solar project and RES
23		Rider present revenue associated with these items, which are proposed to be
24		included in the RES Rider after the implementation of final rates. Costs or
25		revenues associated with the PTC true-up and RECs sales occur only on an
26		actual basis and, as such, require no test year adjustment.

1

This adjustment decreases the MYRP Forecast rate base by \$272.6 million in

2		2022, as well as \$560.9 million and \$760.6 million in years 2023 and 2024
3		respectively. The adjustment has a net zero impact on the MYRP Forecast
4		revenue requirements, as we expect full recovery in the RES rider. Support for
5		these amounts can be found on:
6		• Schedule 10, page 1, row 43, column 20;
7		• Schedule 11, page 2, row 41, column 32;
8		• Schedule 12, page 1, row 52, columns 5 through 7;
9		• Volume 4, Section VIII Adjustments, Tab A44, Rider: RES.
10		
11		26) TCR Rider
12	Q.	Is the Company proposing continued use of the TCR Rider during the
13		MYRP?
14	Α.	Yes. As I describe in detail in Section VIII, Costs Recovered in Riders, we
15		propose continued use of the TCR Rider during the MYRP for the projects that
16		will not be placed in service as of December 31, 2021 and MISO RECB
17		Schedule 26 and 26A revenues net of expenses.
18		
19	Q.	PLEASE DESCRIBE THE TCR RIDER REMOVAL ADJUSTMENT.
20	Α.	The TCR Rider removal adjustment removes all costs and revenues (other than
21		(i) internal labor for all projects and (ii) all ADMS O&M, except software
22		maintenance) from the MYRP Forecast jurisdictional cost of service for the
23		Advanced Distribution Management System (ADMS), Advanced Metering
24		Infrastructure (AMI), Field Area Network (FAN), Time of Use (TOU) Pilot,
25		and LoadSeer projects, as well as MISO RECB Schedule 26 and 26A net
26		revenues, all of which are approved for inclusion in the TCR. We are also

	seeking approval to include our Distributed Intelligence and Sherco-Lyons
	County projects, in the TCR. 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 \$98.807 million in
	2022, as well as \$193.117 million and \$283.589 million in years 2023 and 2024
	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 43, column 21;
	• Schedule 11, page 2, row 41, column 33;
	• Schedule 12, page 1, row 53, columns 5 through 7;
	• Volume 4, Section VIII Adjustments, Tab A45, Rider: TCR.
Q.	DOES THE COMPANY COORDINATE THE TCR RIDER REMOVAL WITH ITS TCR
	RIDER FILINGS?
Α.	Yes. With each filing, we work to ensure coordination between the rate case
	test year and our TCR Rider filing. However, we note that rate case and rider
	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 aligned, there
	are typically variances in the revenue requirement calculations.

1		E. Secondary Cost of Service Calculations
2		27) ADIT Pro-Rate – IRS Required
3	Q.	PLEASE DESCRIBE THE ADIT PRO-RATE ADJUSTMENT THAT IS REQUIRED BY
4		THE IRS AND INCLUDED IN THESE SECONDARY CALCULATIONS.
5	Α.	In general, the IRS tax regulations in Sec. 1.167(l) define a pro-rated schedule
6		for the extent average accumulated deferred income taxes can be used to reduce
7		rate base to comply with the tax normalization requirements of the Code when
8		forecast information is used to set rates. Given that the Company's MYRP
9		filing utilizes forecast test year data, this condition applies. This has been
10		supported by a number of Private Letter Rulings (PLRs) issued by the IRS. In
11		addition, FERC approved the pro-ration logic included in the Company's
12		Attachment O-NSP transmission formula rate of the MISO Open Access
13		Transmission, Energy and Operating Reserve Markets Tariff in Docket No.
14		ER18-2322-000.
15		
16		This secondary calculation limits the ADIT deduction from rate base by
17		applying the IRS defined pro-rate method to only the forecast entries to this
18		balance. Support for this calculation is included in Exhibit(BCH-1),
19		Schedule 19, ADIT Pro-Rate. The IRS requirements for this adjustment are
20		described in more detail in the Direct Testimony of Mr. Moeller.
21		
22		The adjustment impacts the MYRP Forecast revenue requirements by the
23		amounts shown on:
24		• Schedule 10, page 1, row 43, column 22;
25		• Schedule 11, page 2, row 41, column 34;
26		• Schedule 12, page 1, row 56, columns 5 through 7;

1		• Volume 4, Section VIII Adjustments, Tab A46, ADIT Prorate for
2		IRS.
3		
4		28) Cash Working Capital
5	Q.	PLEASE DESCRIBE THE CASH WORKING CAPITAL ADJUSTMENT BEING MADE AS
6		A SECONDARY CALCULATION.
7	Α.	As discussed earlier in Section IV.E, Other Rate Base, the Company has
8		incorporated a secondary calculation to apply the various revenue lead days and
9		expense lag days to the various income statement components to result in the
10		appropriate cash working capital rate base adjustment. The adjustment impacts
11		the MYRP Forecast revenue requirements by the amounts shown on:
12		• Schedule 10, page 1, row 43, column 23,
13		• Schedule 11, page 2, row 41, column 35,
14		• Schedule 12, page 1, row 57, columns 5 through 7,
15		• Volume 4, Section VIII Adjustments, Tab A47, Cash Working Capital
16		Adjustment.
17		
18		29) Change in Cost of Capital
19	Q.	Please describe the impact of the change in the cost of capital
20		ADJUSTMENT.
21	Α.	The change in the cost of capital adjustment is the effect of the changes in the
22		overall cost of capital between the cost of capital (also referred to as the overall
23		rate of return, or ROR) being requested in this case for each year of the MYRP
24		and the effective cost of capital authorized in Docket No. E002/GR-15-826.
25		Table 10 below provides the requested rate of return in this case, and the
26		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

	2022 Test Year	2023 Plan Year	2024 Plan Year
Proposed Rate of Return	7.31%	7.28%	7.30%
Difference relative to 7.08%	0.23%	0.20%	0.22%

On Schedules 11a-11c, 2022-2024 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 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 from 9.20 percent in our 2016-2019 MYRP to 10.20 percent (for final rates only) in this MYRP, 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 2, row 41, column 36;

1		• Volume 4, Section VIII Adjustments, Tab A49, Change in Cost of
2		Capital.
3		
4		30) Net Operating Loss
5	Q.	PLEASE DESCRIBE THE COMPANY'S NET OPERATING LOSS POSITION.
6	Α.	The NSPM income tax determination was in a NOL position through 2018.
7		This means that more deductions existed in the current period than are needed
8		to bring current taxable income to zero. The Company still has federal tax
9		credits that have been deferred and tracked for use in future periods. The
10		Company worked with the Department on this issue, which resulted in a
11		process for reporting these deferred balances and returning to customers the
12		revenue requirement reduction associated with the utilization of these deferred
13		balances in the form of a refund or as a reduction to base rates.
14		
15		NOLs, unused tax credits, and the associated ratemaking treatment are
16		discussed in detail earlier in my testimony in Section V. D. Taxes.
17		
18	Q.	Is the Company proposing an adjustment to base rates related to
19		NOLS IN THIS CASE?
20	Α.	No. The Company was able to utilize the remainder of the deductions
21		previously deferred and currently no DTA is generated in the MYRP. As noted
22		previously in my testimony, any changes in the revenues, expenses, or capital
23		structure will cause the income tax calculation to be changed. This could, in
24		turn, affect the timing of the DTAs being generated and added to rate base.

1	Q.	Is the Company proposing an adjustment to base rates related to
2		DEFERRED TAX CREDITS IN THIS CASE?
3	Α.	Yes. The Company is utilizing federal tax credits during the 2022-2024 MYRP,
4		but due to the amount of federal tax credits earned during the year, the DTA is
5		increasing in each year of the MYRP. As noted previously in my testimony, any
6		changes in the revenues, expenses, or capital structure will cause the income tax
7		calculation to be changed. This could, in turn, affect the timing of the DTAs
8		being generated or consumed and added to or removed from rate base.
9		
10		This adjustment impacts the MYRP Forecast revenue requirements by the
11		amounts shown on:
12		• Schedule 10, page 1, row 43, column 24;
13		• Schedule 11, page 2, row 41, column 37;
14		• Schedule 12, page 1, row 58, columns 5 through 7;
15		• Schedule 20, Net Operating Loss;
16		• Volume 4, Section VIII Adjustments, Tab A48, Net Operating Loss.
17		
18		VIII. COSTS RECOVERED IN RIDERS AND TRACKERS
19		
20	Q.	WHAT TOPICS DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?
21	Α.	In this section, I present our proposed treatment of costs recovered in riders
22		during the MYRP period, including riders that we propose to continue to use
23		and costs we propose to move to base rates. I provide detailed information
24		supporting the adjustments to the MYRP Forecast that I presented in Section
25		VII of my testimony.
26		

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

1

2	Α.	The Company currently uses six cost recovery riders:
3		• Renewable Energy Standards (RES) Rider;
4		• Transmission Cost Recovery (TCR) Rider;
5		• Renewable Development Fund (RDF) Rider;
6		• Conservation Improvement Program (CIP) Rider;
7		Windsource Rider;
8		Renewable Connect Rider; and
9		• Fuel Clause Adjustment Rider (FCA).
10		
11	Q.	WHAT IS THE COMPANY PROPOSING WITH RESPECT TO THE TREATMENT OF
12		COSTS RECOVERED THOUGH RATE RIDERS?
13	Α.	As discussed in greater detail below, we propose to:
14		• Continue use of the RES Rider for recovery of incremental costs for the
15		four repowered wind projects (Grand Meadow Wind Farm, Nobles
16		Wind Farm, Pleasant Valley Wind Farm and Borders Wind Farm) and
17		Northern Wind Farm, as well as the proposed Sherco Solar project. We
18		also propose to include PTCs associated with these wind projects and
19		the PTC true-up for other Company-owned wind projects in base rates.
20		Finally, we propose to share with customers potential proceeds related
21		to any RECs the Company may sell in the future after the implementation
22		of final rates in this case. All current and proposed rider projects and
23		revenue credits will be collected through the RES Rider during the
24		interim rate period.
25		• Continue use of the TCR Rider, with costs for ADMS, AMI, FAN,
26		LoadSeer and TOU Pilot as well as the proposed Distributed Intelligence
		105 Docket No. E002/GR-21-630

1		and Sherco-Lyons County projects, and MISO RECB Schedule 26 and
2		26A net revenues to continue to be included in the rider after
3		implementation of final rates in this case. All current and proposed rider
4		projects and revenue credits will be collected through the TCR Rider
5		during the interim rate period.
6		• Continue use of the RDF Rider, CIP Rider, Renewable Connect Rider,
7		and the FCA in their current forms.
8		Transition Windsource Rider customers to the Renewable Connect Rider
9		and discontinue use of the Windsource Rider.
10		
11		In the following subsections of my testimony, I will address our proposed rate
12		case treatment for each of these riders in detail and discuss how the Company
13		ensures there is no double recovery of these costs.
14		
15	Q.	WHAT IS THE COMPANY'S BASE RATE REVENUE REQUIREMENT EXCLUSIVE OF
16		RIDER ROLL-INS?
17	Α.	Our proposed total revenue requirement in 2022, 2023, and 2024, including our
18		proposed increase in base rates, is approximately \$2.5 billion in 2022, \$2.7
19		billion in 2023 and \$2.8 billion in 2024, as shown in Table 11 below.

1 Table 11 2 **Total Cost Recovery Including Riders** 3 \$ in Thousands **2022 Test** 2023 Plan 2024 Plan 4 Recovery Method Year Year Year 5 Present Revenues \$3,191,440 \$3,256,313 \$3,214,831 395,972 546,123 Cumulative Rate Increase 677,347 6 3,652,285 3,760,954 3,868,787 Proposed Revenues 7 Less: Rider Revenue included in present revenue TCR Rider 87,710 85,495 83,350 8 44,204 48,349 48,261 CIP Rider 9 849,346 849,346 849,346 FCA Rider 37,586 31,666 33,526 **RDF** Rider 10 105,667 87,723 74,837 **RES Rider** 1,089,320 11 1,124,513 1,102,579 Total Rider Revenue included in present revenue \$2,527,772 \$2,658,375 \$2,779,467 Net Base Rate Revenue Requirement 12 13 Rate rider recovery estimates are preliminary, are subject to change, and are also 14 15 subject to the Commission's decisions in individual rate rider dockets. We 16 provide this information so that the Commission, parties, and our customers 17 can understand the combined impact of our requests. 18 19 A. **Rider Recovery** 20 RES Rider 1) 21 WHAT IS THE RES RIDER? Q. 22 The RES Rider is authorized by Minn. Stat. § 216B.1645, subd. 2a for the Α. 23 recovery of a utility's investments, expenses, or costs associated with facilities 24 constructed, owned, or operated by a utility that satisfy the Minnesota 25 Renewable Energy Standard.

1	Q.	What costs are currently included in the RES Rider?
2	Α.	The Commission's Order in Docket No. E002/M-19-732 approved our 2019
3		and 2020 RES Rider request to recover the costs of the following projects in
4		the RES Rider:
5		• Courtenay Wind Farm;
6		• Foxtail Wind Farm;
7		Blazing Star I Wind Farm;
8		• Lake Benton Wind Farm;
9		Blazing Star II Wind Farm;
10		• Crowned Ridge Wind Farm;
11		Jeffers Wind Farm
12		Community Wind North
13		Mower Wind Farm
14		• Freeborn Wind Farm;
15		Dakota Range Wind Farm
16		 PTCs for all wind farms above;
17		 PTC true up for wind farms included in base; and
18		• REC sales proceeds.
19		
20	Q.	WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE RES RIDER DURING
21		THE MULTI-YEAR RATE PLAN?
22	Α.	As described earlier, we propose to:
23		• Move Courtenay Wind Farm, Foxtail Wind Farm, Blazing Star I Wind
24		Farm, Lake Benton Wind Farm, Blazing Star II Wind Farm, Crowned
25		Ridge Wind Farm, Jeffers Wind Farm, Community Wind North, Mower

1		Wind Farm, Freeborn Wind Farm and Dakota Range Wind Farm
2		projects from RES Rider recovery to base rate recovery coincident with
3		implementation of final rates in this rate case;
4		• Begin recovery of costs and PTCs on Borders Wind Re-Power, Pleasant
5		Valley Wind Re-Power, Grand Meadows Wind Re-Power, Nobles Wind
6		Re-Power and Northern Wind Farm as well as the proposed Sherco Solar
7		project in the RES Rider;
8		• In the RES Rider, true-up actual PTCs related to energy production for
9		all wind farms currently in or proposed to roll into base rates compared
10		to the amount included in base rates; and
11		• Include in the RES Rider customers' share of potential proceeds related
12		to any RECs the Company may sell in the future.
13		
14		These costs are fully supported in our 2021 RES Rider petition filed in Docket
15		No. E002/M-20-815, which is pending Commission review and approval or
16		will be included in a future filing.
17		
18	Q.	PLEASE BRIEFLY DESCRIBE THE COMPANY'S REQUEST FOR RECOVERY OF THE
19		PROJECTS GOING INTO SERVICE IN 2022 AND BEYOND IN THE RES RIDER.
20	Α.	As described by Mr. Chamberlain, the Company proposes to recover all projects
21		noted above going into service in 2022 and beyond through the RES Rider. We
22		propose to recover the capital-related revenue requirements and property taxes,
23		as well as incremental operating and maintenance expenses. We also propose
24		to include all of the PTCs associated with the wind projects in the RES Rider.
25		Therefore, we have not included any PTCs for these projects in the 2022-2024
26		MYRP.

1	Q.	How is the RES Rider treated with respect to PTCs in the 2022-2024 $$
2		MYRP?
3	Α.	The Company requests PTC treatment consistent with the previously approved
4		process. Specifically, we request that:
5		1) A new baseline PTC will be set in this rate case. We have included PTC
6		amounts shown in Table 7 above as the base amount in the 2022-2024
7		MYRP. See Schedule 18, Production Tax Credits. These PTCs are
8		generated from the Pleasant Valley, Border, Courtenay, Blazing Star I,
9		Foxtail, Lake Benton, Blazing Star II, Crowned Ridge, Jeffers,
10		Community Wind North, Mower, Freeborn and Dakota Range facilities
11		which are included in the 2022-2024 MYRP.
12		2) The difference between actual and baseline PTCs be recorded in the RES
13		Tracker account.
14		3) The difference will be either refunded to, or recovered from, customers
15		as established in future RES Rider filings.
16		
17		Because we propose that the true-up between the level of PTCs included in base
18		rates through this MYRP and the actual amount of PTCs earned in the
19		respective period would occur through the RES Rider, we do not anticipate a
20		need to address this issue in the base rate revenue requirement in the final
21		compliance filing.

1	Q.	WHAT ADJUSTMENT HAVE YOU MADE TO ENSURE NO DOUBLE RECOVERY OF
2		COSTS RECOVERED IN THE RES RIDER AFTER THE IMPLEMENTATION OF FINAL
3		RATES IN THIS CASE?
4	Α.	The project costs and revenues remaining in the RES Rider have been removed
5		from our 2022-2024 MYRP. A review is also done for each RES filing to ensure
6		that no costs included in base rates are included in the RES filing. I provide
7		information related to the 2022-2024 MYRP adjustment that ensures no double
8		recovery of these costs in Section VII.D. Rider Removals, RES Rider
9		(adjustment 25).
10		
11		2) TCR Rider
12	Q.	WHAT IS THE TCR RIDER?
13	Α.	The TCR Rider is authorized by Minn. Stat. § 216B.16, subd. 7b to allow the
14		recovery of Minnesota jurisdictional costs related to transmission and grid
15		modernization investments and for MISO charges incurred for projects for
16		which MISO assigns regional costs under Schedule 26 and Schedule 26A of its
17		Tariff.
18		
19	Q.	WHAT COSTS ARE CURRENTLY INCLUDED IN THE TCR RIDER?
20	Α.	The Commission approved our 2017 and 2018 TCR Rider request to recover
21		the following projects in the TCR Rider in Docket No. E002/M-17-797, and
22		provisionally approved 2019 and 2020 TCR Rider requests in Docket No.
23		E002/M-19-721:
24		• ADMS;
25		• CapX2020 Brookings;
26		• CapX2020 Fargo;

1		• CapX2020 La Crosse;
2		• Big Stone – Brookings;
3		• Huntley – Wilmarth;
4		• La Crosse – Madison; and
5		 MISO RECB Schedule 26 and 26A net revenue.
6		
7		As of the development of this testimony, the Commission had not yet issued a
8		final decision in Docket No. E002/M-19-721.
9		
10	Q.	WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE TCR RIDER
11		DURING THE MULTI-YEAR RATE PLAN?
12	Α.	As described earlier, we propose to:
13		• Move the three CapX2020 La Crosse projects, CapX2020 Brookings,
14		CapX2020 Fargo, Big Stone-Brookings, La Crosse-Madison and
15		Huntley-Wilmarth projects from TCR Rider recovery to base rate
16		recovery coincident with implementation of final rates in this rate case;
17		• Continue recovery of the ADMS project in the TCR Rider;
18		• Seek recovery of the AMI, FAN, TOU Pilot and LoadSeer as well as the
19		Distributed Intelligence and Sherco-Lyons County projects to be
20		proposed in the TCR Rider;
21		Continue recovery of MISO RECB Schedule 26 and 26A net revenue
22		in the TCR Rider.

1	Q.	PLEASE DESCRIBE THE PROJECTS THAT WILL REMAIN IN THE TCR RIDER AFTER
2		THE IMPLEMENTATION OF FINAL RATES.
3	Α.	The Company is requesting continued recovery of the ADMS and to begin
4		recovery of the AMI, FAN, TOU Pilot and LoadSeer as well as the Distributed
5		Intelligence and Sherco-Lyons County projects to be proposed in the TCR
6		Rider. We propose to recover these projects through the TCR Rider because
7		these are large qualifying projects that are not yet fully in-service. We are also
8		requesting to continue recovery of the MISO RECB Schedule 26 and 26A net
9		revenues through the TCR Rider.
10		
11	Q.	WHAT ADJUSTMENT HAVE YOU MADE TO ENSURE NO DOUBLE RECOVERY OF
12		PROJECTS CONTINUING RECOVERY IN THE TCR RIDER AFTER THE
13		IMPLEMENTATION OF FINAL RATES IN THIS CASE?
14	Α.	The project costs and revenues remaining in the TCR Rider have been removed
15		from our 2022-2024 MYRP. A review is also done for each TCR filing to ensure
16		that no costs included in base, are included in the TCR filing. I provide
17		information related to the 2022-2024 MYRP adjustment that ensures no double
18		recovery of these costs in Section VII.D. Rider Removals, TCR Rider
19		(adjustment 26).
20		
21		3) TCR and RES Rider Roll-in
22	Q.	PLEASE DESCRIBE HOW YOU ARE PROPOSING TO MOVE PROJECTS TO BASE RATES
23		AT THE CONCLUSION OF THIS RATE CASE.
24	Α.	As noted above, we propose to move projects from the TCR and RES riders to
25		base rates at the conclusion of this case because it reduces the Interim Rate
26		increase and clarifies that there is no potential for double recovery of costs.

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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 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. 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. WHAT DOES THE COMPANY PROPOSE TO INCLUDE IN ITS FINAL RATE Q. COMPLIANCE TO SUPPORT MOVEMENT OF THESE PROJECTS FROM THE TCR RIDER TO BASE RATES? We propose to submit TCR and RES Rider compliance reports with final rate These reports will clearly identify the revenue compliance reporting. 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

1		factors. The Company anticipates this process will be similar to the process
2		used to move recovery of CIP costs from the CIP Rider to base rates.
3		
4	Q.	How are the projects that will move to base rates treated during
5		THE INTERIM RATE PERIOD?
6	Α.	During the interim rate period, the Company proposes that the identified
7		projects continue recovery through the TCR or RES Riders, along with the
8		other costs that we are proposing to continue to recover through the TCR and
9		RES Riders after implementation of final rates.
10		
11	Q.	HOW WILL YOU ENSURE NO DOUBLE RECOVERY OF THESE PROJECT COSTS
12		OCCURS DURING THE INTERIM RATE PERIOD?
13	Α.	We are proposing to continue recovery of these projects through the TCR and
14		RES Riders during the interim period and to move these projects into base rates
15		at the end of this case. The 2022 test year also includes the project costs in the
16		test year cost of service as well as the project revenues in present revenue. Thus,
17		an interim rate adjustment is necessary to ensure no double recovery of these
18		costs during the interim rate period. Accordingly, our 2022 and 2023 Interim
19		Rate requests each include an adjustment to remove the projects identified to
20		roll into base rates and the present revenue from the development of Interim
21		Rates.
22		
23	Q.	Please provide additional detail related to the Interim Rate
24		ADJUSTMENT FOR THE TCR AND RES RIDER COSTS.
25	Α.	The Interim Rate Adjustment removes the project costs and present revenue
26		included in the 2022 test year and 2023 plan year from the Interim Cost of

1 Service. This adjustment decreases the Interim Cost of Service rate base and 2 present revenue by the amounts shown in Table 12 below. 3 Table 12 4 Rider Removals from Interim Rates (\$ in millions) 5 Decrease in Decrease in 6 Rate Base **Present Revenue** 2022 2022 7 2023 2023 TCR Rider \$587.5 \$565.5 \$87.7 \$85.5 8 **RES Rider** 1,501.8 1,344.1 105.7 87.7 9 \$193.4 TOTAL Rider Removal \$2,089.3 \$1,909.6 \$173.2 10 11 Additional detail on these adjustments can be found in Volume 1, Notice of 12 Change in Rates and Interim Rate Petition, Interim Rate Supporting Schedules 13 and Workpapers. 14 15 O. DO YOU PROVIDE ANY OTHER INFORMATION RELATED TO TREATMENT OF TCR 16 AND RES RIDER COSTS AND PROJECTS DURING THE MULTI-YEAR RATE PLAN 17 PERIOD? Exhibit___(BCH-1), Schedule 22, Rider Roll-in Timeline, provides a 18 Yes. 19 timeline illustrating how projects will be rolled into base rates or will remain in 20 the TCR and RES Riders during the course of the multi-year rate plan. 21 RDF Rider 22 4) 23 WHAT COSTS ARE RECOVERED THROUGH THE RDF RIDER? 24 Commission-approved RDF costs pursuant to Minn. Stat. §§ 116C.779 and 25 216B.1645, subd. 2 are recovered from retail customers through the RDF Rider.

1	Q.	HOW IS THE RDF RIDER TREATED IN THE MYRP FORECAST?
2	Α.	Both revenue and amortization expense for the RDF Rider are included in the
3		MYRP Forecast. The amount of each is equal and therefore, does not
4		contribute to the MYRP Forecast deficiency. Any true-up of the revenues and
5		costs will occur in the RDF Rider, such that there will be no need to address a
6		change in revenue requirement in the final compliance filing.
7		
8		5) CIP Rider
9	Q.	WHAT COSTS ARE RECOVERED THROUGH THE CIP RIDER?
10	Α.	The CIP Rider is designed to recover conservation and demand-side
11		management program costs that are incremental to the level collected in base
12		rates. Base electric rates are designed to include conservation and demand-side
13		management cost at an authorized level approved by the Deputy Commissioner
14		of the Minnesota Department of Commerce, Division of Energy Resources for
15		a given test year. The CIP Rider collects any incremental conservation and
16		demand-side management costs above the authorized level in final base rates.
17		
18		The CIP performance incentive is also recovered through the CIP Rider and is
19		designed to compensate the Company for lost sales due to Company
20		conservation efforts. The annual projected CIP performance incentive margin
21		is included in the Other Revenue budget. The CIP performance margin is
22		intended as an incentive to the Company and represents budgeted level in
23		anticipation of achieving the CIP goals. An adjustment is made to remove the
24		estimated performance margin from the MYRP Forecast. Failure to include
25		this adjustment would flow the annual CIP performance incentive to customers

1		by overstating operating revenues in the MYRP Forecast and, therefore,
2		understating the revenue deficiency for the test year.
3		
4	Q.	How is the CIP Rider treated in the MYRP Forecast?
5	Α.	As discussed in Section VII, Annual Adjustments to the MYRP, the CIP Rider
6		amount in the case is at the level needed to assure that the CIP revenue (Base
7		and Rider) is equal to the expense in the MYRP Forecast. With the total amount
8		of CIP expense and CIP revenue equal, the overall CIP program does not
9		contribute to the test year deficiency.
10		
11		6) Windsource Rider
12	Q.	WHAT COSTS ARE RECOVERED THROUGH THE WINDSOURCE RIDER?
13	Α.	Costs related to the Windsource program, a stand-alone retail service program
14		with discrete revenues, purchase power contracts and operating expenses, are
15		recovered through the Windsource Rider.
16		
17	Q.	How is the Windsource Rider treated in the MYRP Forecast?
18	Α.	All revenue and expense related to the Windsource program ended in 2021;
19		therefore, there is no revenue or expense in the MYRP Forecast.
20		
21	Q.	Is the company anticipating any change in the Windsource Rider
22		DURING THE MYRP?
23	Α.	Yes. The Company anticipates transitioning Windsource customers to
24		Renewable*Connect over a period of time. All transactions associated with the
25		transition will occur within the respective mechanism and there is no impact to

	the COSS. Further information is provided in Section VII, Annual Adjustments
	to the MYRP.
	7) Renewable*Connect Rider
Q.	WHAT COSTS ARE RECOVERED THROUGH THE RENEWABLE*CONNECT RIDER?
Α.	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?
Α.	All revenue and expense related to the Renewable*Connect program are
	excluded from the MYRP Forecast. The Renewable*Connect Rider removal
	adjustment shown in column 31 of Schedules 11a-11c, 2022-2024 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 MYRP.
	8) Fuel Clause Adjustment
Q.	WHAT COSTS ARE RECOVERED THROUGH THE FCA?
Α.	Fuel and purchased energy are recovered from customers through the FCA.
	A. Q. Q.

- 1 Q. How is the FCA treated in the MYRP Forecast?
- 2 A. Both revenue and fuel expenses recovered through the FCA are included in the
- 3 MYRP Forecast, and the total amount of each is equal. Any true-up of the
- 4 revenues and costs during the MYRP Forecast will occur in the FCA and,
- 5 therefore, there will be no need to address a change in revenue requirement in
- 6 the final compliance filing. I provide a reconciliation of fuel costs and revenues
- 7 in the Cost of Service in Schedule 21, Fuel Reconciliation. As required by the
- 8 Commission in its November 5, 2019 Order Approving Compliance Filings in
- 9 Docket No. E999/CI-03-802, this schedule illustrates that fuel revenues 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.

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B. Trackers and Deferrals

- 14 9) Electric Vehicle Program Tracker
- 15 Q. Please describe the status of the electric vehicle tracker and
- 16 DEFERRAL.
- 17 A. In its June 22, 2015 Order in Docket No. E002/M-15-111, the Commission
- approved the Company's use of a tracker account to defer costs associated with
- 19 electric vehicle (EV) rate education and outreach activities. Consistent with
- 20 Minn. Stat. § 216B.1614, subd. 2(a)(2), the Company attributes costs to the
- 21 tracker associated with providing general EV information, as well as EV rate-
- specific information. Additionally, in granting approval for several EV pilots in
- 23 its July 17, 2019 Order in Docket No. E002/M-18-643, the Commission
- 24 approved deferred accounting for Xcel Energy's O&M. This deferred
- accounting applied to expenses incurred between the date of the Commission's
- 26 Order (July 17, 2019) and January 1, 2020.

1	Q.	WHAT IS THE COMPANY'S PROPOSED TREATMENT OF EV PILOT COSTS DURING
2		THE MYRP?
3	Α.	The Company proposes to include in base rates the capital and O&M expenses
4		for 2022 to 2024 associated with Commission-approved EV pilots and
5		programs, as well as new offerings for which the Company intends to seek
6		approval during the MYRP period. These EV pilots and programs and the
7		associated budgets are discussed in Ms. Bloch's Direct Testimony.
8		
9		The Company is also proposing to incorporate the balance in the EV tracker
10		established in Docket No. E002/M-15-111 and the final deferral balance related
11		to Docket No. E002/18-643 into a three-year amortization over the MYRF
12		period. This will ensure that all costs for prior years that have been approved
13		for tracking and deferral will be reviewed and included in base rates. We
14		propose to include all EV tracker costs through December 31, 2021. The total
15		amount of these costs will be known at the time of Rebuttal Testimony (which
16		is anticipated to be due after the conclusion of calendar year 2021) and will
17		therefore be updated at that time.
18		
19		Finally, as Ms. Bloch discusses, certain O&M costs that are unknown at this
20		time and incremental to the MYRP budget will continue to be included in our
21		established EV cost tracker. Use of the EV tracker is consistent with prior
22		Commission approvals in our separate EV program and pilot dockets and wil
23		be addressed in proceedings proposing any new offerings.

1		10) Credit Card Fee Tracker
2	Q.	What is the Company proposing with respect to credit card fees?
3	Α.	Company witness Mr. Christopher Cardenas describes that the Company
4		historically passed through credit card company fees to individual customers
5		who use credit cards to pay their utility bills, as a per-transaction fee.
6		However, customers have come to expect the ability to use credit cards to pay
7		a variety of bills without being separately charged a fee for each payment. As
8		Mr. Cardenas explains, we are proposing to include credit card fees in our base
9		rate structure so that the fees are part of overall O&M rather than passed to
10		customers as individual transaction fees. Because this program would be new
11		for the Company, we are proposing to establish a baseline amount of credit
12		card fees in base rates and track actual costs above or below that baseline for
13		recovery or return to customers in a future rate case.
14		
15	Q.	WHY DOES THE COMPANY BELIEVE A TRACKER WOULD BE APPROPRIATE?
16	Α.	Given that this is a new means of managing credit card costs for NSPM, prior
17		to program implementation it is difficult to predict how it will affect customer
18		behavior and the extent to which it will change Company credit card payment
19		costs. While Mr. Cardenas supports the Company's initial estimates, a tracker
20		would mitigate any risk of over- or under-collection so that only actual costs are
21		ultimately recovered through rates.
22		
23	Q.	PLEASE DESCRIBE THE COMPANY'S TRACKER PROPOSAL IN MORE DETAIL.
24	Α.	As Mr. Cardenas explains in his Direct Testimony, the Company currently
25		estimates annual total electric credit card fees of approximately \$6.6 million,
26		once customers are no longer charged individually for each transaction. We

1	propose to establish this amount in our test year revenue requirement and track
2	actual annual fees above and/or below this baseline between initiating the
3	program (approximately January 1, 2024) and our next Minnesota electric rate
4	case. We would then address the net regulatory asset or liability in our next rate
5	case.

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7 Q. WHY IS THIS TRACKER PROPOSAL REASONABLE?

A. This will be a new program for NSPM, which we anticipate will modernize payment options for our customers and enhance our customers' experience with their electric utility service. The tracker will ensure the Company does not over- or under-collect credit card fees in the test year in relation to this program and will also enable reporting in our next rate case on the extent to which customers take advantage of this option.

14

IX. COMPLIANCE WITH PRIOR COMMISSION ORDERS

16

15

- 17 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 address 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.

1		
2		A. Independent Auditor Requirement
3	Q.	Please describe the requirement for the Company to have the
4		REVENUE REQUIREMENT IN THIS PROCEEDING EVALUATED BY AN
5		INDEPENDENT AUDITOR.
6	Α.	On June 14, 2021, the Commission issued an Order Denying Reconsideration
7		with respect to our proposal to implement several true-ups for 2021 that
8		allowed us to withdraw our electric rate case filing in Docket No. E002/GR-
9		20-723 (Stay Out Proposal).8 Specifically, after the Commission's initial
10		approval of the Stay Out Proposal, the Company filed a letter explaining that
11		we found a miscalculation of our general rate case revenue requirement of
12		approximately \$43.2 million. This error was associated with inadvertently
13		including certain gas demand costs twice within the Company's cost of service.
14		The Commission issued a notice requesting comment on the matter, and
15		ultimately met to consider how to address the matter. The Commission
16		determined that reconsideration was not warranted, but also required the
17		Company to take the following steps to evaluate its internal procedures:
18		
19		2. The Commission hereby requires Xcel to hire, at its own expense, an
20		independent auditor to evaluate its 2021 return on equity and file a copy of the
21		independent auditor's evaluation by May 15, 2022.
22		
23		3. Xcel must report improvements to its validation procedures and must hire,
24		at its own expense, an independent auditor to review the Company's validation

⁸ In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of 2021

⁸ In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of 2021 Sales True-Up Mechanisms, Docket No. E002/M-20-743, ORDER DENYING RECONSIDERATION (June. 14, 2021).

1 2 3		procedures and resulting revenue requirement deficiency in its next general rate case filing.9
4	Q.	How is the Company addressing these requirements?
5	Α.	Order Point 2, pertaining to the evaluation of our 2021 return on equity,
6		requires an evaluation of our actual return on equity for 2021 after the year
7		ends. We anticipate undertaking this evaluation in early 2021 and filing the
8		required report accordingly.
9		
10		For purposes of this rate case proceeding, we have (a) reviewed and made
11		improvements to our validation procedures, particularly as applicable to our
12		cost of service in this proceeding; and (b) hired D&T to perform agreed upon
13		procedures related to our validation procedures and revenue requirement
14		deficiency for this general rate case filing.
15		
16	Q.	WHAT IMPROVEMENTS DID THE COMPANY MAKE TO ITS VALIDATION
17		PROCEDURES AS PART OF THIS RATE CASE FILING?
18	Α.	The Company has made the following changes to address the duplication of
19		gas demand cost in our electric rate case filing in Docket No. E002/GR-20-
20		723:
21		• Modified the interchange revenue and expense to separate the fuel costs
22		components from each, which allowed the Company to evaluate all
23		components of fuel costs and revenues in the MYRP cost of service.
24		These components are shown in Volume 4, Section IV. Revenue, Tab
25		R4. Interchange and Section V. O&M, Tab O2-3 Interchange.

⁹ *Id.* at p. 3, Order Points 2 and 3.

1		 Enhanced the fuel reporting included on Schedule 11a-c to show all
2		components of fuel in column 39. This enhanced reporting improves
3		the visibility of fuel costs and revenues included in our MYRP cost of
4		service, and verifies the costs and revenues collected in the FCA and
5		included in our rate case cost of service net to zero as presented in
6		column 39, row 41.
7		• Expanded the fuel expense and revenue details on Schedule 21 and
8		provided references to Schedule 11a-c.
9		
10		An independent review of all base data and adjustments has always been a part
11		of the Company's normal practice. In addition to the specific fuel validation
12		changes referenced above, the Company has also standardized a template for
13		the review of all base data and adjustments to the MYRP cost of service.
14		Through this process we have simplified reviews as well as increased visibility
15		into the impact each adjustment has on the cost of service.
16		
17	Q.	PLEASE EXPLAIN THE PROCESS BY WHICH D&T EVALUATED NSPM'S
18		REVENUE REQUIREMENT DEFICIENCY AND VALIDATION PROCEDURES, IN
19		COMPLIANCE WITH THE COMMISSION'S ORDER POINT 3.
20	Α.	Our process for the D&T review included several steps, including:
21		• In coordination with D&T, developed agreed upon procedures and
22		a scope of work, as well as information to be provided by the
23		Company to facilitate the procedures.
24		• The Company provided its cost of service, as well as a listing of all
25		base data and adjustments, to D&T. The Company also provided
26		the tracking of the independent review of all base data and

1		adjustments to the cost of service, to enable D&T to verify that an
2		independent review occurred.
3		Based on the Minnesota Electric cost of service and the listing of all
4		base data and adjustments, the auditor verified the applicable
5		support for each input to the cost of service and each adjustment,
6		and also confirmed that the Company's independent review of the
7		base data and adjustments properly reflected attention to each item.
8		
9	Q.	What were the results of the $D\&T$ evaluation?
10	Α.	D&T performed the list of procedures agreed to by the Company to evaluate
11		the 2022-2024 MYRP cost of service and revenue requirement deficiency
12		calculation and no exceptions were noted. A copy of the D&T Report is
13		attached to my Direct Testimony as Schedule 23.
14		
15		B. General Rate Case – Docket No. E002/GR-12-961
16		1) Mapping to FERC Form 1
17	Q.	Please describe the Company's compliance with requirements to
18		RECONCILE INFORMATION BETWEEN THE COMPANY'S FERC FORM 1 AND
19		GENERAL LEDGER.
20	Α.	Order Point 47 from the Commission's September 3, 2013 order in Docket
21		E002/GR-12-961 (the 12-961 Order) stated:
22 23 24 25 26 27 28 29		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

1 2 3		Information Request 128-Revised, marked in the record as Exhibit 163, DOC Attachment ACB-15.
4		These requirements have been met. The mapping to FERC Form 1 is located
5		in Volume 3, Required Information, Section IV, Other Required Information,
6		Tab 5, GAAP/FERC/COSS Comparison. There we provide accounting of the
7		NSPM Total Company for 2018 to 2020. For each year, we provide the GAAP
8		financial statements reconciled to the FERC Form 1. We then provide the
9		FERC Form 1 reconciled to the Minnesota Jurisdictional Annual Report Total
10		Company amounts.
11		
12		2) Changes Between Actuals and MYRP Forecast
13	Q.	PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REPORTING
14		REQUIREMENTS RELATED TO DEVIATIONS BETWEEN MOST RECENT ACTUALS
15		AND THE MYRP FORECAST.
16	A.	Order Point 47 of the 12-961 Order also requires explanations for deviations
17		ten percent or greater (+/- 10 percent) "between actuals and [the Company's]
18		test-year request." Explanations of operating expense variations of +/-5
19		percent and +/-\$500,000 are provided for 2020 actuals compared to the 2022
20		budget by FERC account in Volume 6, Budget Documentation, Variance
21		Analysis. Explanations of variations of +/-10 percent on rate base items are
22		provided with the schedules in Volume 3, Required Information, Section IV,
23		Other Required Information, Tab 5, GAAP/FERC/COSS Comparison.

1		3) Financial Labeling
2	Q.	WHAT ARE THE REQUIREMENTS RELATED TO LABELING FINANCIAL
3		INFORMATION?
4	Α.	In the Revenue Requirement Rebuttal Testimony in Docket E002/GR-12-961,
5		the Company agreed to make efforts to label all costs and revenues to the
6		relevant financial source: Xcel Energy Services, Inc.; NSP System; NSP-
7		Minnesota or NSPM (Total Company - electric and gas utilities); NSPM
8		Electric; and State of Minnesota Electric Jurisdiction.
9		
10	Q.	HOW HAS THE COMPANY COMPLIED WITH THIS COMMITMENT?
11	Α.	We have made a good faith effort to satisfy this commitment throughout all
12		testimony in this case. For reference, following is a list of the labels used and
13		the definitions of each.
14		• Xcel Energy or XEI: The entire enterprise – XES, NSPM, NSPW, SPS,
15		PSCo, and affiliate companies.
16		XES: Xcel Energy Services: Xcel Energy's service company that provides
17		services across all Xcel Energy affiliate companies.
18		• NSPM (Total Company): Northern States Power Company-Minnesota,
19		providing service to electric and gas customers in Minnesota, North
20		Dakota, and South Dakota.
21		• NSPW (Total Company): Northern States Power Company-Wisconsin,
22		providing service to electric and gas customers in Wisconsin and
23		Michigan.
24		<u>NSP System</u> : The combined NSPM and NSPW electric production and
25		transmission system.

1	<u>NSPM Electric</u> : Northern States Power Company, including the portion
2	allocated or direct assigned to the electric utility.
3	• State of Minnesota: Items physically located in the State of Minnesota
4	such as distribution facilities or property taxes assessed by the State.
5	• State of Minnesota Electric Jurisdiction: Amounts direct assigned or
6	allocated to the electric utility and to the State of Minnesota. Interchange
7	Agreement billings to and from NSPW are reflected in revenues and
8	expenses, respectively.
9	State of Minnesota Electric Jurisdiction net of Interchange Agreement
10	billings to NSPW or State of Minnesota Electric Jurisdiction, net of
11	Interchange: The net amount allocated to the cost of service for electric
12	customers in the State of Minnesota. The portion of the item billed to
13	NSPW through the Interchange Agreement has been netted against the
14	item to show the net impact to Minnesota electric customers.
15	
16	Further, other Company witnesses provide amounts in their testimonies from
17	several applicable financial sources. To the extent practicable, they have also
18	provided the State of Minnesota jurisdictional amount. The jurisdictional
19	amounts were developed under my guidance and are consistent with
20	development of allocators as explained in the CAAM presented by Mr.
21	Baumgarten as Exhibit (RLS-1), Schedule 3 to his Direct Testimony, and
22	in Schedule 3, Cost of Service Study Summary, to my Direct Testimony. In
23	order to provide further context, an index to these financial sources is included

as Exhibit___(BCH-1), Schedule 5, Labeling of Financial Sources.

24

Wholesale Customer Study

1

4)

2	Q.	WHAT REQUIREMENT RELATED TO WHOLESALE CUSTOMERS DO YOU ADDRESS?
3	Α.	With respect to the costs and revenues related to services provided to wholesale
4		customers, the Company and Department agreed as follows:
5 6 7 8 9 10 11 12 13		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. ¹⁰
15		
16	Q.	How has the Company complied with this requirement?
17	A.	Schedule 14, Wholesale Customer Study, provides the required information.
18		The study does not address wholesale transmission revenues. Wholesale
19		transmission revenues and associated costs are discussed in the Direct
20		Testimony of Mr. Benson.
21		
22		C. Decommissioning
23	Q.	PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REQUIREMENTS
24		RELATED TO NUCLEAR DECOMMISSIONING.
25	Α.	A discussion of the Company's compliance history and the status of pending
26		dockets with respect to nuclear decommissioning and the use of Department of
27		Energy payments is contained in Section VII. Triennial Nuclear
28		Decommissioning Costs, of Mr. Moeller's Direct Testimony.

¹⁰ May 22, 2013 Issues List Page 19 in Docket No E002/GR-12-961.

1	
1	

2

3

D. Other Compliance Requirements

1) Relief and Recovery Docket Tracking

Q. What is the compliance requirement from the Company's COVID-19
 Relief & Recovery Docket?

6 In response to the Commission's request for projects that could assist with Α. Minnesota's economic recovery from the COVID-19 pandemic, 11 the 7 Company proposed to accelerate certain Distribution, Transmission, and Gas 8 Operations projects and sought a Commission determination that acceleration 9 of these projects was appropriate. 12 The Commission concluded that the 10 11 proposed projects had the potential to be consistent with the Commission's 12 request for proposals that could assist with recovery from the COVID-19 13 pandemic; that the Commission would determine project prudence in future rate cases; and that the acceleration of these projects "would not be the sole 14 basis for any disapproval in the future." ¹³ Further, the Commission required 15 16 the Company to "track investment spending for the acceleration of the 17 projects separately from base rates, with clear delineation between portions 18 that are included in base rates and those that are incremental to base rates."14

19

¹¹ In the Matter of an Inquiry into Utility Investments that May Assist in Minnesota's Economic Recovery form the COVID-19 Pandemic, REPORT COVID-19 RELIEF & RECOVERY, Docket No. 20-492 (June 17, 2020).

¹² In the Matter of an Inquiry into Utility Investments that May Assist in Minnesota's Economic Recovery form the COVID-19 Pandemic, ORDER DETERMINING THAT PROPOSALS HAVE THE POTENTIAL TO BE CONSISTENT WITH COVID-19 ECONOMIC RECOVERY, Docket No. E,G-999/CI-20-492 (March 12, 2021).

¹³ Id. at Order Point 1.

¹⁴ Id. at Order Point. 2.

1 Q. IS THE COMPANY REQUESTING RATE RECOVERY OF ANY ACCELERATED 2 PROJECTS IN THIS ELECTRIC RATE CASE?

Yes. As discussed by Company witnesses Mr. Ian Benson, Ms. Kelly Bloch and Mr. Randy Capra, the Company is requesting approval of certain Transmission Asset Health, EV Rebates and Asset Removal projects as part of its MYRP in this case. While these witnesses provide additional support for the projects in their respective Direct Testimony, I total the electric projects that have been accelerated and are proposed for inclusion in base rates in Table 13 below:

Α.

Table 13 COVID-19 Relief & Recovery Capital Additions Total Company (\$s in millions)

14	
15	
16	
17	
18	
19	
20	
21	
22	
23	
24	

Project Name	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
Major Line Rebuild program	\$0.0	\$14.1	\$52.1	\$56.2
Substation Breakers ELR program	\$0.0	\$4.0	\$14.7	\$9.8
Steel Pole Replacement program	\$0.2	\$9.6	\$5.9	\$4.5
S&E Line and Substation programs	\$0.0	\$8.0	\$6.0	\$6.0
Line ELR program	\$3.5	\$5.0	\$5.8	\$4.6
Transformers ELR program	\$0.1	\$5.7	\$4.0	\$3.0
Relay ELR program	\$0.0	\$0.0	\$1.5	\$4.2
Major Line Refurbishment program	\$0.1	\$2.7	\$0.0	\$0.0
EV Rebates & Fast Charging Network	\$0.0	\$66.3	\$50.8	\$37.2
Asset Removal at Blue Lake, Granite City, Key City, Riverside, Sherco Ash Pond, Minnesota Valley	RWIP	RWIP	RWIP	RWIP
Total	\$3.9	\$115.4	\$140.8	\$125.5

1	Q.	HAS THE COMPANY INCLUDED THESE PROJECTS IN ITS COST RECOVERY
2		REQUESTS IN ANY OTHER DOCKET BEFORE THE COMMISSION?
3	Α.	No. These programs were specifically tracked for Relief and Recovery purposes
4		and are included in the cost of service in this rate case on that basis. Conversely,
5		while the Company is pursuing other projects outside this rate case such as the
6		wind re-power and Sherco solar projects referenced earlier in my Direct
7		Testimony, the Company is requesting recovery of those projects through the
8		appropriate riders.
9		
10	Q.	HAS THE COMPANY IDENTIFIED SPECIFIC COSTS ASSOCIATED WITH
11		ACCELERATING THESE PROJECTS?
12	Α.	Because these are each projects that the Company otherwise intended to
13		complete, and simply have been accelerated as discussed by Mr. Benson and
14		Mr. Capra, the costs simply show up in the Company's rate request earlier than
15		they otherwise might have. Therefore, while the Company will recover the costs
16		of these projects earlier than it otherwise might have, customers are receiving
17		the benefits earlier, including efforts to make jobs available and advance the
18		work of Minnesota's Energy Utility Diversity Group as described by the
19		sponsors of these projects.
20		
21	Q.	Is the Company providing the Commission with information
22		REGARDING THESE PROJECTS IN ANY OTHER DOCKETS?
23	Α.	Yes. Consistent with the Commission's March 12 and March 16, 2021 Orders
24		in Docket No. E,G-999/CI-20-492 (March 12, 2021), the Company continues
25		to track its spending related to these COVID-19 Relief & Recovery projects

1		and the Company has been providing this information to the Commission as
2		part of its quarterly compliance filings in that docket. ¹⁵
3		
4		2) Incentive Compensation Refunds
5	Q.	WHAT ARE THE REQUIREMENTS RELATED TO INCENTIVE COMPENSATION
6		REFUNDS?
7	Α.	In Docket No. E002/GR-10-971, the Commission required Xcel Energy to
8		continue to refund all incentive compensation payments recoverable in rates
9		under the Order, but not paid.
10		
11	Q.	How is compliance with these requirements reflected in the
12		COMPANY'S RATE CASE REQUEST?
13	Α.	For 2020 (paid in March 2021), incentive plan payouts were at a level that
14		required the Company to refund electric customers \$2.1 million, as reported in
15		our annual incentive compensation compliance filing in Docket Nos.
16		E002/GR-92-1185, G002/GR-92-1186, and E,G002/M-21-369 on June 1,
17		2021. Our 2016-2019 MYRP, which was based on a 2016 test year and escalated
18		to a 2019 plan year, included the budgeted incentive compensation costs
19		accrued in 2019 and payable in March 2020, after excluding certain costs (e.g.,
20		executive long-term incentive).
21		
22		The 2022 test year includes the budgeted incentive compensation costs accrued
23		in 2022 and payable in March 2023, after excluding certain costs (e.g., certain
24		LTI, which I identified in Section VII.B.5, Annual Adjustments to the MYRP).

¹⁵ In the Matter of an Inquiry into Utility Investments that May Assist in Minnesota's Economic Recovery form the COVID-19 Pandemic, 2021 SECOND QUARTER REPORT COVID-19 RELIEF & RECOVERY, Docket No. 20-492 (July 30, 2021).

1	Q.	DOES THE COMPANY PROPOSE ANY CHANGES TO THE AIP INCENTIVE REFUND
2		PROGRAM?
3	Α.	Yes. Once rates have been established at the conclusion of this rate proceeding,
4		we propose to eliminate the yearly AIP compliance filing requirement and any
5		associated reports regarding the AIP. The Company is also proposing the
6		elimination of the AIP refund. Company witness Ms. Lowenthal discusses this
7		proposal in her Direct Testimony.
8		
9		3) Non-Asset Based Trading Activities—Fully Allocated Cost Study and
10		Incremental Cost Study
11	Q.	PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH COST ALLOCATION
12		REQUIREMENTS FOR NON-ASSET BASED TRADING.
13	Α.	In Docket No. E002/GR-10-971, the Company was directed to file in its next
14		rate case both an incremental and fully allocated cost study of its non-asset
15		based trading activities. In Direct Testimony in Docket E002/GR-15-826, we
16		requested that only a fully allocated cost study be submitted in future rate cases,
17		as the incremental study is not used to determine the level of costs to charge to
18		this activity. No opposition was raised in those proceedings. Therefore, only
19		the fully allocated cost study is provided with this testimony as Schedule 17,
20		Non-Asset Based Trading Cost Study.
21		
22		4) Nuclear Fuel Outage Costs
23	Q.	PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REPORTING
24		REQUIREMENTS FOR NUCLEAR FUEL OUTAGE COSTS.
25	Α.	In Docket No. E002/GR-08-1065, the Company was directed to include an
26		analysis of nuclear plant outage costs as shown in Exhibit 86 to the hearing

1		record. The required information is included in Volume 4, Section VIII Rate
2		Base (Plant), Tab P4-1, Nuclear Outage Amortization. Volume 4 also includes
3		schedules in support of the 2023 and 2024 Plan Year nuclear fuel outage costs.
4		These schedules provide a determination of the Minnesota retail jurisdiction
5		revenue requirements associated with the Nuclear Outage Deferral and
6		Amortization method, as well as a comparison to the Direct Expense method
7		for the MYRP Forecast.
8		
9		5) Capacity Cost Report
10	Q.	Please describe the Company's compliance with requirements
11		RELATED TO CAPACITY COSTS.
12	Α.	In Docket No. E002/GR-08-1065, the Commission ordered the Company to
13		describe NSP System short-term and long-term capacity costs by contract. The
14		required information is attached as Exhibit(BCH-1) Schedule 15, Capacity
15		Cost Study, which is Trade Secret. The methodology for budgeting capacity
16		costs for the 2022-2024 MYRP is similar to that described by Mr. David G.
17		Horneck in his Direct Testimony from Docket No. E002/GR-10-
18		971. Contracts with which NSPM has long-term obligations to purchase
19		capacity remain the same as described in that docket. The Company anticipates
20		that it can meet the expected MISO capacity planning reserve requirements for
21		the 2022 planning year from its current generation and long term purchased
22		capacity contracts. Therefore, the Company does not expect to purchase short
23		term capacity contracts for the 2022 test year.

1		6) Lobbyist Compensation
2	Q.	Please describe the Company's compliance with reporting
3		REQUIREMENTS RELATED TO LOBBYIST COMPENSATION.
4	Α.	In Docket No. E002/GR-10-971, we agreed to include a report of the total
5		compensation for employees engaged in lobbying with an explanation of the
6		costs included and excluded in the rate request. This information is provided
7		in the Direct Testimony of Mr. Husen.
8		
9		7) North Dakota Investment Tax Credits
10	Q.	What are the requirements related to the North Dakota
11		INVESTMENT TAX CREDITS?
12	Α.	In Docket No. E-002/M-15-805, the Company was instructed to share non-
13		Minnesota state tax credits as follows:
14 15 16 17 18 19 20		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.
21	Q.	How has the Company complied with these requirements?
22	Α.	The North Dakota state credit for North Dakota-located wind generation is the
23		only non-Minnesota state credit utilized by NSPM. Due to the size of the
24		credits available relative to the North Dakota state taxable income, it is
25		anticipated that the utilization of these credits will be limited by taxable income
26		and not specifically known until North Dakota state tax returns are filed. The
27		potential for credits are primarily the result of the Border, Courtenay, and
28		Foxtail Wind Farms. Pursuant to the Commission's April 11, 2017 Order in

1		Docket No. E002/M-17-818, we will include North Dakota investment tax
2		credits (NDITCs) associated with the wind farms mentioned above in our
3		calculation of the revenue requirements in the RES rider.
4		
5		8) Capital True-Up
6	Q.	PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH CAPITAL TRUE-UP
7		REPORTING REQUIREMENTS.
8	Α.	Continuing the capital true-up reporting from our 2016-2019 MYRP in
9		accordance with the Commission's June 14, 2021 Order in Docket No.
10		E002/M-20-743, the Company will submit an annual compliance filing in May
11		2022 for calendar year 2021. This compliance filing will compare the actual
12		capital-related revenue requirements (actuals) to the capital forecast revenue
13		requirements (forecast). The Company has also proposed to continue the
14		capital true-up, as discussed by Company witness Mr. Chamberlain.
15		
16		9) FERC Transmission Audit Refunds
17	Q.	Please describe the Company's compliance with the FERC
18		Transmission Audit refunds.
19	Α.	In accordance with the Commission's recent hearing on the Company's
20		Transmission Cost Recovery Rider adjustment in Docket No. E002/M-19-721,
21		I address how the FERC Transmission Audit refund impacts all components
22		other than Schedule 26/26A. The FERC audit resulted in refunds to NSP
23		Transmission Formula Rate customers. The refunds were included in the 2019
24		annual true up and are currently being refunded as part of the 2021 transmission
25		formula rate. These refunds would have resulted in an increased cost to retail

1		customers; however, with no rate case filing for 2021 there is no impact on retail
2		customers.
3		
4		10) Recurring Compliance Reporting Requirements
5	Q.	WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION?
6	Α.	Below, I provide information on compliance requirements of a recurring nature
7		reported upon in each rate case.
8		
9		a) Edison Electric Institute Spare Transformer Sharing Agreement
10	Q.	Please describe the Company's compliance with reporting
11		REQUIREMENTS ON THE SPARE TRANSFORMER SHARING AGREEMENT.
12	Α.	The Commission's Order in Docket No. E002/PA-06-1662 required the
13		Company to report any sales or purchases of transformers made under the EEI
14		Spare Transformer Sharing Agreement in its next rate case. Over the life of the
15		program there have been no triggering events to initiate a transformer sale or
16		purchase under the program. Therefore, Xcel Energy has not sold or purchased
17		any transformers under this agreement. Since this provision has not been
18		triggered in many years, the Company proposes to discontinue this reporting in
19		future rate cases.
20		
21		b) Minnesota Emissions Allowance
22	Q.	PLEASE DESCRIBE THE COMPANY'S USE OF APPROVED DEFERRED ACCOUNTING
23		RELATED TO EMISSIONS ALLOWANCES.
24	Α.	In Docket No. E002/M-94-13, the Commission ordered deferred accounting
25		for revenues from the sale of certain emission allowances until the Company's
26		next general rate case, where the effects of then-new changes to the FERC

1		Uniform System of Accounts could be examined. The Company has continued
2		the deferral over several rate cases, but the accumulated unamortized deferred
3		balance of emission sales is less than \$5,000. Due to the small level in this
4		account that has been accumulating since 2010 when the deferral was last
5		resolved, combined with the limited market for these allowances, the Company
6		is proposing to discontinue the deferral of emission allowances with no
7		adjustment in this proceeding. Thus, there is no adjustment included in this
8		filing.
9		
10		c) Advantage Service (a/k/a HomeSmart)
11	Q.	Please describe the Company's compliance with requirements
12		RELATED TO HOME SMART.
13	Α.	In Docket No. E002/GR-91-1, the Company was directed to require NSP
14		Advantage Service (now branded as Xcel Energy HomeSmart) to: 1) pay a
15		return on the use of the Company's billing services asset; 2) compensate the
16		Company for its personnel's referral time; and 3) compensate the Company for
17		use of its mailing lists. The Company has complied with these requirements.
18		
19		d) Liberty Paper
20	Q.	WHAT ARE THE REQUIREMENTS RELATED TO LIBERTY PAPER?
21		In Docket No. E002/M-93-1253, the Commission ordered the Company to
22		segregate the cost of constructing a steam pipeline from Sherco to Liberty
23		Paper, Inc. from utility rate base, and to record operating and maintenance
24		expenses to non-utility operations.

1	Q.	How has the Company complied with these requirements?
2	Α.	When the Commission approved the amended agreement with Liberty Paper,
3		Inc., in its February 21, 2020 Order in Docket No. E002/M-19-663, the
4		Commission included a requirement that, for the duration of steam sales to
5		Liberty Paper, Inc., the Company must demonstrate the reasonableness of the
6		Company's proposed cost allocations related to the steam sales. The allocation
7		of costs to Liberty Paper, Inc. and the reasonableness of those costs, are
8		discussed in Section III of NSPM's CAAM, which is Schedule 3 to Mr.
9		Baumgarten's Direct Testimony.
10		
11		e) Tax Benefit Transfer Leases
12	Q.	Please describe the Company's compliance with requirements
13		RELATED TO TAX BENEFIT TRANSFER LEASES.
14	Α.	In Docket No. G002/GR-97-1606, the Company was directed to treat Tax
15		Benefit Transfer (TBT) leases consistent with prior Commission approved
16		methodology. There are no TBTs included in the MYRP. Since this provision
17		has not been triggered in many years, the Company proposes to discontinue this
18		reporting in future rate cases.
19		
20		f) Sale of Renewable Energy Credits
21	Q.	Please describe the Company's compliance with requirements
22		RELATED TO THE SALE OF RECS.
23	Α.	In Docket No. E002/GR-08-1065, the Company was directed to flow revenues
24		from the sale of RECs through the RES Rider. A petition to pass certain RECs
25		to customers using the FCA was approved by the Commission in Docket No.
26		E002/M-12-1132. The Commission ordered the proceeds from the sale of

1		RECs be returned to customers through the RES Rider unless the Commission
2		makes a specific determination to allow a sharing of the proceeds. The
3		Company has complied with this requirement.
4		
5		g) Competitive Bidding
6	Q.	PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REQUIREMENTS FOR
7		ANY NON-PERFORMANCE PENALTIES RELATED TO COMPETITIVELY BID
8		GENERATION.
9	Α.	In Docket No. E002/M-95-174 the Company was permitted to offer Company-
10		owned generation to compete against other provider offerings. The Company
11		is required to track capacity-related non-performance penalties on NSP
12		Generation projects for return to customers. We have incurred no such
13		penalties. Since this provision has not been triggered in many years, the
14		Company proposes to discontinue this reporting in future rate cases.
15		
16		X. CONCLUSION
17		
18	Q.	PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.
19	Α.	I recommend that the Commission determine an overall 2022 retail revenue
20		requirement of \$3.65 billion and 2022 revenue deficiency of \$396.0 million for
21		the Company's Minnesota jurisdictional electric operation, determined by the
22		cost of service for the 2022 test year. I also recommend a revenue deficiency
23		for each year of the MYRP as follows:

1		Table 14								
2		2022-2024 Revenue Requests								
3		Minnesota Jurisdictional Deficiency Net of Interchange (\$s in millions)								
4			MYRP Year	2022	2023	2024	,			
5			Amount, cumulative	\$396.0	\$546.1	\$677.3				
6			Amount, incremental	\$396.0	\$150.2	\$131.2				
7			Average % increase, incremental *	12.2%	4.8%	4.2%				
8			* The average percent increase							
9		revenue	request over the forecasted pre	esent revenues 11	n each applicab	le year, less prio	r year(s).			
10		Lastly, I	also recommend the Co	mmission gr	ant a 2022 i	nterim rate in	ncrease of			
11		\$288.3 n	nillion, and an additiona	1 2023 interi	im rate incre	ease of \$135.	1 million,			
12		for the Company's Minnesota jurisdictional operation.								
13										
14	Q.	DOES TH	HIS CONCLUDE YOUR DIE	RECT TESTIM	YYONY?					
15	Α.	Yes, it d	oes.							

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.

Employment History

Xcel Energy - Minneapolis, MN

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

Target Corporation - Minneapolis, MN

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

Copeland Buhl and Company - Wayzata, MN

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

Education

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

Docket No. E002/GR-21-630 Exhibit____(BCH-1), Schedule 2

Page 1 of 1

SUMMARY OF REVENUE REQUIREMENTS (\$000's)

		Adjusted Proposed Test Year	Adjusted Proposed Plan Year	Adjusted Proposed Plan Year
Line	<u>Description</u>	2022	2023	2024
1	Average Rate Base	\$10,931,371	\$11,445,687	\$11,918,156
2	Operating Income (Before AFUDC)	\$483,710	\$412,324	\$348,826
3	Allowance for Funds Used During Construction	\$33,212	\$31,766	\$38,536
4	Total Available for Return (Line 2 + Line 3 + Rounding)	\$516,922	\$444,090	\$387,362
5	Overall Rate of Return (Line 4 / Line 1)	4.73%	3.88%	3.25%
6	Required Rate of Return	7.31%	7.28%	7.30%
7	Operating Income Requirement (Line 1 x Line 6)	\$799,083	\$833,246	\$870,025
8	Income Deficiency (Line 7 - Line 4)	\$282,161	\$389,156	\$482,664
9	Gross Revenue Conversion Factor	1.40335	1.40335	1.40335
10	Revenue Deficiency (Line 8 x Line 9)	\$395,972	\$546,123	\$677,347
11	Retail Related Revenue Under Present Rates	\$3,256,313	\$3,214,831	\$3,191,440
12	Percentage Increase Needed in Overall Revenue (Line 10 / Line 11)	12.16%	16.99%	21.22%
13	Retail Related Revenue Under Present Rates EXCLUDING FUEL	\$2,406,967	\$2,365,485	\$2,342,094
14	Percentage Increase Needed Excluding Fuel (Line 10 / Line 13)	16.45%	23.09%	28.92%

Northern States Power Company
State of MN Electric

DocketNo. E002/GR-21-630

Page 1 of 4

Exhibit __ (BCH-1), Schedule 3

Line	ne Minnesota Electric Jurisdiction					
No.		2022 Test Year	2023 Plan Year	2024 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	<u>18.94%</u>	<u>18.94%</u>	<u>18.94%</u>		
5	Composite Tax Rate	28.74%	28.74%	28.74%		
6	Revenue Conversion Factor (1/(1Composite 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	0.94%	0.80%	1.47%		
11	Cost of Long Term Debt	4.13%	4.12%	4.09%		
12	Cost of Common Equity	10.20%	10.20%	10.20%		
13	Ratio of Short Term Debt	0.61%	1.00%	0.42%		
14	Ratio of Long Term Debt	46.89%	46.50%	47.08%		
15	Ratio of Common Equity	52.50%	52.50%	52.50%		
16	Weighted Cost of STD	0.01%	0.01%	0.01%		
17	Weighted Cost of LTD	1.94%	1.91%	1.93%		
18	Weighted Cost of Debt	1.95%	1.92%	1.94%		
19	Weighted Cost of Equity	5.36%	5.36%	5.36%		
20	Required Rate of Return	7.31%	7.28%	7.30%		
21						
22	Rate Base					
23	Plant Investment	22,725,537	23,505,685	24,520,225		
24	Depreciation Reserve	<u>10,346,933</u>	10,779,757	11,568,947		
25	Net Utility Plant	12,378,604	12,725,928	12,951,278		
26	CWIP	436,833	506,554	616,842		
27		•	•	•		
28	Accumulated Deferred Taxes	2,758,524	2,832,943	2,854,352		
29	DTA - NOL Average Balance	• •		-		
31	DTA - Federal Tax Credit Average Balance	(580,419)	<u>(745,797)</u>	(900,149)		
32	Total Accum Deferred Taxes	2,178,105	2,087,146	1,954,203		
33						
34	Cash Working Capital	(152,392)	(163,615)	(179,078)		
35	Materials and Supplies	154,701	154,701	154,701		
36	Fuel Inventory	69,767	69,767	69,767		
37	Non-plant Assets and Liabilities	97,858	123,255	148,557		
38	Customer Advances	(7,200)	(7,200)	(7,200)		
39	Customer Deposits	(28,273)	(28,273)	(28,273)		
40	Prepaids and Other	69,357	71,669	75,069		
41	Regulatory Amortizations	<u>90,221</u>	<u>80,047</u>	<u>70,696</u>		
42	Total Other Rate Base Items	294,039	300,350	304,239		
43						
44	Total Rate Base	10,931,371	11,445,687	11,918,156		
45						

Northern States Power Company State of MN Electric

Line	ine Minnesota Electric Jurisdiction					
No.		2022 Test Year	2023 Plan Year	2024 Plan Year		
46	Operating Revenues					
47	Retail	3,255,934	3,214,449	3,191,054		
48	Interdepartmental	380	382	386		
49	Other Operating Rev - Non-Retail	<u>595,815</u>	609,232	620,259		
50	Total Operating Revenues	3,852,129	3,824,063	3,811,699		
51						
52	<u>Expenses</u>					
53	Operating Expenses:					
54	Fuel	989,947	990,992	990,847		
55	Deferred Fuel	5,926	5,888	5,848		
56	Variable IA Production Fuel	8,061	8,043	8,043		
57	Purchased Energy - Windsource	<u>0</u>	<u>0</u>	<u>0</u>		
58	Fuel & Purchased Energy Total	1,003,935	1,004,922	1,004,738		
59	Production - Fixed	412,997	421,250	418,673		
60	Production - Fixed IA Investment					
61	Production - Fixed IA O&M	43,924	54,688	50,286		
62	Production - Variable	3,799	3,800	3,831		
63	Production - Variable IA O&M	6,033	5,351	5,334		
64	Production - Purchased Demand	<u>142,779</u>	145,513	<u>148,306</u>		
65	Production Total	609,533	630,603	626,430		
66	Regional Markets	9,562	9,824	10,059		
67	Transmission IA	113,571	121,955	126,155		
68	Transmission	144,026	143,985	146,142		
69	Distribution	120,803	126,532	128,391		
70	Customer Accounting	51,137	45,999	51,861		
71 72	Customer Service & Information	130,239	133,653	133,705		
73	Sales, Econ Dvlp & Other	7,541	8,297	8,862		
73 74	Administrative & General Total Operating Functions	236,784 2 427 130	243,259 2 460 020	251,092 2 487 425		
75	Total Operating Expenses	2,427,130	2,469,029	2,487,435		
76	Depreciation	815,505	849,115	899,980		
77	Amortization	61,229	55,267	54,647		
78	THIOTUZAUOII	01,227	33,207	37,077		
79	Taxes:					
80	Property Taxes	203,210	216,060	232,678		
81	ITC Amortization	(1,223)	(1,219)	(1,211)		
82	Deferred Taxes	98,142	47,605	(6,583)		
83	Deferred Taxes - NOL	7-3,-1-	,	(0,000)		
84	Less State Tax Credits deferred					
85	Less Federal Tax Credits deferred	(164,636)	(166,121)	(142,583)		
86	Deferred Income Tax & ITC	(67,718)	(119,735)	(150,377)		
87	Payroll & Other Taxes	26,699	27,435	28,135		
88	Total Taxes Other Than Income	162,192	123,761	110,436		
89		,	•	,		

Line		Minnesota Electric Jurisdiction			
No.		2022 Test Year	2023 Plan Year	2024 Plan Year	
90	Income Before Taxes				
91	Total Operating Revenues	3,852,129	3,824,063	3,811,699	
92	less: Total Operating Expenses	2,427,130	2,469,029	2,487,435	
93	Book Depreciation	815,505	849,115	899,980	
94	Amortization	61,229	55,267	54,647	
95	Taxes Other than Income	<u>162,192</u>	123,761	<u>110,436</u>	
96	Total Before Tax Book Income	386,073	326,892	259,202	
97					
98	<u>Tax Additions</u>				
99	Book Depreciation	815,505	849,115	899,980	
100	Deferred Income Taxes and ITC	(67,718)	(119,735)	(150,377)	
101	Nuclear Fuel Burn (ex. D&D)	100,282	97,191	100,112	
102	Nuclear Outage Accounting	35,338	39,292	40,732	
103	Avoided Tax Interest	15,585	16,487	22,275	
104	Other Book Additions	<u>5,371</u>	<u>5,371</u>	<u>5,541</u>	
	Total Tax Additions	904,362	887,720	918,263	
106					
107	Tax Deductions				
108	Total Rate Base	10,931,371	11,445,687	11,918,156	
109	Weighted Cost of Debt	1.95%	1.92%	1.94%	
110	Debt Interest Expense	213,162	219,757	231,212	
111	Nuclear Outage Accounting	24,846	54,407	32,419	
112	Tax Depreciation and Removals	1,364,542	1,194,343	1,097,959	
113	NOL Utilized / (Generated)				
114	Other Tax / Book Timing Differences	<u>9,975</u>	<u>9,917</u>	<u>8,489</u>	
	Total Tax Deductions	1,612,525	1,478,425	1,370,079	
116					
	State Taxes			4	
118	State Taxable Income	(322,090)	(263,813)	(192,614)	
119	State Income Tax Rate	9.80%	9.80%	9.80%	
120	State Taxes before Credits	(31,565)	(25,854)	(18,876)	
121	Less State Tax Credits applied	(946)	(946)	(946)	
	Total State Income Taxes	(32,511)	(26,800)	(19,822)	
123	7				
	Federal Taxes				
125	Federal Sec 199 Production Deduction			/	
126	Federal Taxable Income	(289,580)	(237,013)	(172,792)	
127	Federal Income Tax Rate	21.00%	21.00%	21.00%	
128	Federal Tax before Credits	(60,812)	(49,773)	(36,286)	
129	Less Federal Tax Credits	<u>(4,314)</u>	(8,859)	(33,516)	
	Total Federal Income Taxes	(65,126)	(58,632)	(69,802)	
131	mm				
	Total Taxes	1.0 100	100 574	440.404	
	Total Taxes Other than Income	162,192	123,761	110,436	
	Total Federal and State Income Taxes	(97,637)	(85,432)	(89,624)	
	Total Taxes	64,555	38,329	20,812	
136	T . 10	2.052.422	2.024.042	2 044 600	
	Total Operating Revenues	3,852,129	3,824,063	3,811,699	
138	Total Expenses	3,368,419	3,411,739	3,462,874	
139	AFDC D.1.	0.540	0.440	44.520	
	AFDC Debt	9,710	9,418	11,569	
141	AFDC Equity	23,502	22,348	26,968	
142	NT-4 Turner	#47.000	444.000	20= 240	
143	Net Income	516,922	444,090	387,362	

Line		Minnesota Electric Jurisdiction				
No.		2022 Test Year	2023 Plan Year	2024 Plan Year		
144						
145	Rate of Return (ROR)					
146	Total Operating Income	516,922	444,090	387,362		
147	<u>Total Rate Base</u>	<u>10,931,371</u>	<u>11,445,687</u>	<u>11,918,156</u>		
148	ROR (Operating Income / Rate Base)	4.73%	3.88%	3.25%		
149						
150	Return on Equity (ROE)					
151	Net Operating Income	516,922	444,090	387,362		
152	Debt Interest (Rate Base * Weighted Cost of Debt)	(213,162)	(219,757)	(231,212)		
153	Earnings Available for Common	303,760	224,333	156,149		
154	Equity Rate Base (Rate Base * Equity Ratio)	<u>5,738,970</u>	<u>6,008,985</u>	<u>6,257,032</u>		
155	ROE (earnings for Common / Equity)	5.29%	3.73%	2.50%		
156						
157	Revenue Deficiency					
158	Required Operating Income (Rate Base * Required Return)	799,083	833,246	870,025		
159	Net Operating Income	516,922	444,090	387,362		
160	Operating Income Deficiency	282,161	389,156	482,664		
161						
162	Revenue Conversion Factor (1/(1Composite Tax Rate))	1.403351	1.403351	1.403351		
163	Revenue Deficiency (Income Deficiency * Conversion Factor)	395,972	546,123	677,347		
164						
165	Total Revenue Requirements					
166	Total Retail Revenues	3,256,313	3,214,831	3,191,440		
167	Revenue Deficiency	<u>395,972</u>	<u>546,123</u>	<u>677,347</u>		
168	Total Revenue Requirements	3,652,285	3,760,954	3,868,787		
169						
170	Excluding Fuel Expense and Revenue					
171	Total Fuel Related Expense and Revenue	995,786	997,065	996,953		
172	Line 137 Less Fuel Related Revenue	2,856,343	2,826,998	2,814,747		
173	Line 138 Less Fuel Related Expense	2,372,633	2,414,674	2,465,921		
174	Revised Net Income (including AFUDC)	516,922	444,090	387,362		
174	Change due to Excluding Fuel	0	0	0		

		_		Minnesota Electric Jurisdiction								
Line	Summary Cash Working Capital		Lead/Lag	2022 Te	Test Year		2023 Pla	an Year		2024 PI	ın Year	
No.	Summary Cash Working Capital		Days	Dollars	Dollar x Days		Dollars	Dollar x Days	Do	ollars	Dollar x Days	
1	<u>Fuel Expenses</u>	-				_			-	-		
2	Coal and Rail Transport		15.48	120,583	1,866,630		120,583	1,866,630		120,583	1,866,630	
3	Gas for Generation		38.95	138,800	5,406,261		138,800	5,406,261		138,800	5,406,261	
4	Oil		11.71	27	316		27	316		27	316	
5	Nuclear and EOL			99,092		_	99,025			98,955		
6	Subtotal Fuel Expenses			358,502	7,273,207	_	358,436	7,273,207		358,366	7,273,207	
7	Purchased Power											
8	Purchases		39.52	759,244	30,005,322		763,356	30,167,838		766,120	30,277,066	
9	Interchange		37.25	143,385	5,341,084		151,559	5,645,571		155,731	5,800,984	
10	SubTotal Purchased Power			902,629	35,346,406	_	914,915	35,813,408		921,851	36,078,050	
11	Labor and Related											
12	Regular Payroll		11.89	360,733	4,289,115		380,866	4,528,496		380,998	4,530,067	
13	Incentive		246.18	14,057	3,460,581		14,479	3,564,398		14,913	3,671,333	
14	Pension and Benefits		37.25	62,455	2,326,447		61,605	2,294,769		60,213	2,242,939	
15	SubTotal Labor and Related			437,245	10,076,142	_	456,949	10,387,663		456,124	10,444,339	
				-	-		-	-		-	-	
16	All Other Operating Expenses		42.79	839,305	35,913,840		862,423	36,903,072		880,706	37,685,388	
17	Property taxes		357.82	203,297	72,743,582		217,125	77,691,683		234,411	83,876,788	
18	Employer's Payroll Taxes		31.64	26,699	844,757		27,435	868,052		28,135	890,203	
19	Gross Earnings Tax		60.43	80,114	4,841,312		80,114	4,841,312		80,114	4,841,312	
20	Federal Income Tax		37.00	(73,686)	(2,726,389)		(96,189)	(3,559,007)		(112,683)	(4,169,260)	
21	State Income Tax		29.50	(36,913)	(1,088,948)		(38,309)	(1,130,111)		(32,411)	(956,118)	
22	State Sales Tax Customer Billings	_	35.07	166,467	5,837,989		166,467	5,837,989		166,467	5,837,989	
23	Total Expenses	A		2,903,657	169,061,900	_	2,949,366	174,927,269	2	,981,080	181,801,899	
24	Net Annual Expense			58.22	463,183		59.31	479,253		60.99	498,087	
25	Revenues											
26	Retail Revenue		40.05	3,308,678	132,512,566		3,319,223	132,934,884	3	,341,150	133,813,045	
27	Late Payment		-	5,215			5,215			5,215		
28	Interdepartmental		-	380			382			386		
29	Misc Services		40.05	3,408	136,498		3,407	136,448		3,316	132,792	
30	Rentals		(101.87)	4,737	(482,590)		4,765	(485,400)		4,793	(488,312)	
31	Interchange		37.25	437,477	16,296,016		449,355	16,738,492		461,240	17,181,189	
32	Retail Rev Lag Days		40.05	18,731	750,178		17,398	696,778		14,694	588,497	
33	MISO		14.00	5,463	76,476		5,468	76,555		5,474	76,632	
34	Wholesale Lag Days		32.49	221,026	7,181,146		221,985	7,212,305		222,628	7,233,192	
35	Total Revenues	В		4,005,116	156,470,291	=	4,027,199	157,310,062	4	,058,896	158,537,035	
36	Net Annual Amount			39.07	428,686		39.06	430,986		39.06	434,348	
37	Expense/Revenue Factor	C = A/B			72.499%			73.236%			73.446%	
38	Allocated Revenue Amount	D = B * C			<u>310,792</u>			<u>315,638</u>			<u>319,010</u>	
39	Net Cash Working Capital	E = D - A			(152,392)			(163,615)			(179,078)	

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	<u>Topic</u>	Witness	Financial Source
1	Policy	Chamberlain	NSPM Electric
2	Revenue Requirements	Halama	State of MN Electric Jurisdiction
3	Capital Structure	Johnson	NSPM (Total Company)
4	Return on Equity	D'Ascendis	State of MN Electric Jurisdiction
5	MYRP ROE	Lyons	N/A
6	Budgeting	Ostrom	NSPM Electric
7	Sales Forecast	Goodenough	NSPM Electric
8	Nuclear Operations	Gardner	NSPM Electric
9	Transmission	Benson	NSPM Electric
10	Energy Supply	Capra	NSPM Electric
11	Distribution	Bloch	NSPM Electric /
			State of MN Electric Jurisdiction
12	Business Systems	Remington	NSPM (Total Company)
13	Customer Care/Bad Debt	Cardenas	NSPM Electric
14	Cost Allocations	Baumgarten	NSPM Electric
15	Property Tax	Arend	NSPM (Total Company)
16	Insurance	Miller	XEI and NSPM (Total Company)
17	Employee Expenses	Husen	NSPM (Total Company)
18	Depreciation	Moeller	State of MN Electric Jurisdiction
19	Pension and Benefits Expense	Schrubbe	State of MN Electric Jurisdiction
20	Pension Investments	Inglis	N/A
21	Compensation and Benefits	Lowenthal	Xcel Energy, NSPM (Total
			Company), and NSPM Electric
22	CCOSS	Peppin	State of MN Electric Jurisdiction
23	Rate Design/Decoupling	Paluck	State of MN Electric Jurisdiction

Northern States Power Company Electric Utility - State of Minnesota

DETAILED CASE DRIVERS

Test Year Drivers - Revenue Requirements - Incremental Amounts in millions

	Increase (Decrease) 2022 TY to 2019 MYRP*	Increase (Decrease) 2023 TY to 2022 TY	Increase (Decrease) 2024 TY to 2023 TY	3-Year MYRP
Capital Related	40.4			
Nuclear	40.6	8.2	6.9	55.7
Steam	(15.4)	(17.8)	1.2	(32.0)
Wind	202.9	(20.1)	(12.9)	169.9
All Other Production	3.1	8.8	7.3	19.3
Transmission	84.9	13.3	12.4	110.6
Distribution	60.6	34.6	33.3	128.5
General and Intangible	56.5	28.2	19.4	104.1
DTA (Federal Credits & NOL)	19.2	10.9	10.5	40.6
Other Rate Base	(1.2)	(0.1)	(0.1)	(1.4)
Cost of Capital	92.0	4.3	4.0	100.4
TOTAL Capital Related	543.2	70.5	82.0	695.7
Amortizations	17.2	(0.0)	(2.5)	14.7
Taxes				
Taxes - Other	29.7	8.1	2.9	40.7
PTCs	(125.1)	(6.0)	(1.1)	(132.3)
Property Tax	4.4	12.8	16.6	33.9
Payroll Tax	(3.2)	0.7	0.7	(1.8)
TOTAL Taxes	(94.2)	15.7	19.1	(59.5)
Operating Expense				
Nuclear	(84.4)	7.1	4.8	(72.5)
Steam	(47.4)	7.0	(5.2)	(45.6)
Wind	31.4	(6.0)	(2.7)	22.7
Purchased Demand	14.3	2.7	2.8	19.8
All Other Production	11.4	10.2	(3.9)	17.7
Transmission	30.5	(0.0)	2.2	32.6
Transmission Interchange	(16.6)	8.4	4.2	(4.0)
Distribution	9.6	5.7	1.9	17.2
Regional Markets	2.3	0.3	0.2	2.8
Customer Accounting / Info / Service	8.1	(4.4)	6.4	10.1
A&G	12.4	6.5	7.8	26.7
TOTAL O&M	(28.5)	37.5	18.5	27.5
Other Margin Impacts				
Sales Change	98.0	19.5	10.1	127.7
TCR and RES Revenue	(193.4)	20.2	15.0	(158.2)
Other Revenue	53.6	(13.2)	(11.1)	29.4
TOTAL Other Margin Impacts	(41.7)	26.5	14.1	(1.1)
TOTAL Net Incremental Deficiency	396.0	150.2	131.2	677.3

^{*}The 2019 plan year cost of service from the 2016-2019 MYRP 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.

COMPARISON OF DETAILED RATE BASE COMPONENTS

Test Year Ending December 31, 2022 (\$000's)

Line <u>No.</u>	Description	General Rate Case Filing Docket No. E002/GR-15-826 (A)	General Rate Case Filing Docket No. E002/GR-21-630 Final Rates (B)	<u>Change</u> (C) = (B) - (A)
	Electric Plant as Booked			
1	Production	\$10,060,608	\$12,602,186	\$2,541,578
2	Transmission	2,397,725	3,683,180	1,285,455
3	Distribution	3,658,370	4,387,561	729,191
4	General	888,530	1,087,644	199,114
5	Common	781,187	964,966	183,779
6	TOTAL Utility Plant in Service	\$17,786,420	\$22,725,537	\$4,939,117
	Reserve for Depreciation			
7	Production	\$6,015,790	\$6,977,459	\$961,668
8	Transmission	619,062	818,963	199,901
9	Distribution	1,391,483	1,560,971	169,488
10	General	451,746	558,584	106,838
11	Common	412,713	430,957	18,244
12	TOTAL Reserve for Depreciation	\$8,890,795	\$10,346,933	\$1,456,139
	Net Utility Plant in Service			
13	Production	\$4,044,818	\$5,624,727	\$1,579,909
14	Transmission	\$1,778,663	2,864,217	1,085,555
15	Distribution	\$2,266,887	2,826,590	559,703
16	General	\$436,784	529,061	92,276
17	Common	\$368,473	534,009	165,535
18	Net Utility Plant in Service	\$8,895,625	\$12,378,604	\$3,482,979
19	Utility Plant Held for Future Use	\$0	\$0	\$0
20	Construction Work in Progress	\$380,350	\$436,833	\$56,483
21	Less: Accumulated Deferred Income Taxes	\$2,302,072	\$2,178,105	(\$123,967)
22	Cash Working Capital	(\$111,130)	(\$152,392)	(\$41,262)
	Other Rate Base Items:			
23	Materials and Supplies	\$135,797	\$154,701	\$18,904
24	Fuel Inventory	73,476	69,767	(3,708)
25	Non-Plant Assets & Liabilities	27,456	97,858	70,401
26	Customer Advances	(5,562)	(7,200)	(1,639)
27	Interest on Customer Deposits	(28,127)	(28,273)	(146)
28	Prepaids and Other	85,941	69,357	(16,584)
29	Regulatory Amortizations	\$50,579	90,221	39,642
30	Total Other Rate Base Items	\$339,561	\$446,430	\$106,870
31	Total Average Rate Base	\$7,202,334	\$10,931,371	\$3,729,037

RATE BASE SCHEDULES

Detailed Rate Base Components (\$000's)

Line <u>No.</u>	Description	2022 Test Year Adjusted (1)	2023 Plan Year Adjusted (1)	2024 Plan Year Adjusted (1)
	Electric Plant as Booked			
1	Production	\$12,602,186	\$12,543,687	\$12,749,709
2	Transmission	3,683,180	3,878,352	4,067,600
3	Distribution	4,387,561	4,744,230	5,124,628
4	General	1,087,644	1,229,875	1,365,201
5	Common	964,966	1,109,541	1,213,087
6	TOTAL Utility Plant in Service	\$22,725,537	\$23,505,685	\$24,520,225
	Reserve for Depreciation			
7	Production	\$6,977,459	\$7,096,188	\$7,535,471
8	Transmission	818,963	881,905	948,447
9	Distribution	1,560,971	1,644,203	1,741,690
10	General	558,584	633,874	716,716
11	Common	430,957	523,587	626,623
12	TOTAL Reserve for Depreciation	\$10,346,933	\$10,779,757	\$11,568,947
	Net Utility Plant in Service			
13	Production	\$5,624,727	\$5,447,500	\$5,214,238
14	Transmission	2,864,217	2,996,448	3,119,153
15	Distribution	2,826,590	3,100,027	3,382,938
16	General	529,061	596,000	648,485
17	Common	534,009	585,954	586,464
18	Net Utility Plant in Service	\$12,378,604	\$12,725,928	\$12,951,278
19	Utility Plant Held for Future Use	\$ 0	\$ 0	\$0
20	Construction Work in Progress	\$436,833	\$506,554	\$616,842
21	Less: Accumulated Deferred Income Taxes	\$2,178,105	\$2,087,146	\$1,954,203
22	Cash Working Capital	(\$152,392)	(\$163,615)	(\$179,078)
	Other Rate Base Items:			
23	Materials and Supplies	\$154,701	\$154,701	\$154,701
24	Fuel Inventory	69,767	69,767	69,767
25	Non-Plant Assets & Liabilities	97,858	123,255	148,557
26	Customer Advances	(7,200)	(7,200)	(7,200)
27	Interest on Customer Deposits	(28,273)	(28,273)	(28,273)
28	Prepaids and Other	69,357	71,669	75,069
29	Regulatory Amortizations	90,221	80,047	70,696
30	Total Other Rate Base Items	\$446,430	\$463,965	\$483,317
31	Total Average Rate Base	\$10,931,371	\$11,445,687	\$11,918,156

⁽¹⁾ Revenues and expenses for riders have been included where applicable.

STATEMENT OF OPERATING INCOME

2019 Final Compliance versus 2022 Test Year (\$000s)

Line		General Rate Case Filing E002/GR-15-826	General Rate Case Filing E002/GR-21-630	
No.	<u>Description</u>	Final Rates	Test Year	Change
	Operating Revenues	(A)	(B)	(C) = (B) - (A)
1	Retail	3,051,778	3,255,934	\$204,156
3	Interdepartmental	672	380	(293)
4	Other Operating	687,000	595,815	(91,185)
5	Gross Earnings Tax	007,000	0	0
6	Total Operating Revenues	\$3,739,450	\$3,852,129	\$112,679
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	\$1,125,206	\$1,003,935	(\$121,271)
8	Power Production	691,533	619,095	(72,438)
9	Transmission	243,697	257,597	13,900
10	Distribution	111,186	120,803	9,618
11	Customer Accounting	50,555	51,137	582
12	Customer Service & Information	95,067	130,239	35,172
13	Sales, Econ Dvlp & Other	69	7,541	7,472
14	Administrative & General	224,433	236,784	12,351
15	Total Operating Expenses	\$2,541,744	\$2,427,130	(\$114,614)
16	Depreciation	\$568,522	\$815,505	\$246,983
17	Amortizations	21,871	\$61,229	39,357
	Taxes:			
18	Property	\$198,796	\$203,210	\$4,415
19	Gross Earnings	0	0	0
20	Deferred Income Tax & ITC	107,334	(67,718)	(175,051)
21	Federal & State Income Tax	(67,264)	(97,637)	(30,373)
22	Payroll & Other	29,896	26,699	(3,197)
23	Total Taxes	\$268,761	\$64,555	(\$204,206)
24	Total Expenses	\$3,400,898	\$3,368,419	(\$32,479)
25	AFUDC	\$27,894	\$33,212	\$5,318
26	Total Operating Income	\$366,445	\$516,922	\$150,476

Note: Revenues reflect calendar month sales.

STATEMENT OF OPERATING INCOME

2022 Test Year, 2023-2024 Plan Years (\$000s)

Line		2022	2023	2024
No.	<u>Description</u>	Test Year	Plan Year	Plan Year
	On anoting Payanuas	(A)	(B)	(C)
1	Operating Revenues Retail	3,255,934	3,214,449	3,191,054
3	Interdepartmental	3,233,934	382	3,171,034
4	Other Operating	595,815	609,232	620,259
5	Gross Earnings Tax	0	007,232	020,237
6	Total Operating Revenues	\$3,852,129	\$3,824,063	\$3,811,699
U	Total Operating Revenues	Ψ5,052,127	Ψ5,024,005	ψ5,011,077
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	\$1,003,935	\$1,004,922	\$1,004,738
8	Power Production	619,095	640,427	636,490
9	Transmission	257,597	265,940	272,297
10	Distribution	120,803	126,532	128,391
11	Customer Accounting	51,137	45,999	51,861
12	Customer Service & Information	130,239	133,653	133,705
13	Sales, Econ Dvlp & Other	7,541	8,297	8,862
14	Administrative & General	236,784	243,259	251,092
15	Total Operating Expenses	\$2,427,130	\$2,469,029	\$2,487,435
16	Depreciation	815,505	849,115	899,980
17	Amortizations	61,229	55,267	54,647
	Taxes:			
18	Property	\$203,210	\$216,060	\$232,678
19	Gross Earnings	0	0	0
20	Deferred Income Tax & ITC	(67,718)	(119,735)	(150,377)
21	Federal & State Income Tax	(97,637)	(85,432)	(89,624)
22	Payroll & Other	26,699	27,435	28,135
23	Total Taxes	\$64,555	\$38,329	\$20,812
24	Total Expenses	\$3,368,419	\$3,411,739	\$3,462,874
25	AFUDC	\$33,212	\$31,766	\$38,536
26	Total Operating Income	\$516,922	\$444,090	\$387,362

Note: Revenues reflect calendar month sales.

RATE BASE SCHEDULES

Detailed Rate Base Components (\$000's)

Proposed Test Year 2022

			Total Utility		Minr	nesota Jurisdi	ction
Line <u>No.</u>	<u>Description</u>	Unadjusted (A)	Adjustments (B)	Adjusted (C) (A) + (B)	<u>Unadjusted</u> (D)	Adjustments (E)	Adjusted (F) (D) + (E)
	Electric Plant as Booked						
1	Production	\$14,692,403	(\$155,860)	\$14,536,543	\$12,758,046	(\$155,860)	\$12,602,186
2	Transmission	4,230,685	0	4,230,685	3,683,180	0	3,683,180
3	Distribution	5,040,431	(41,246)	4,999,185	4,428,808	(41,246)	4,387,561
4	General	1,296,068	(42,070)	1,253,998	1,129,714	(42,070)	1,087,644
5	Common	1,116,798	(8,575)	1,108,223	973,541	(8,575)	964,966
6	TOTAL Utility Plant in Service	\$26,376,384	(\$247,751)	\$26,128,633	\$22,973,289	(\$247,751)	\$22,725,537
	Reserve for Depreciation						
7	Production	\$8,015,457	\$6,030	\$8,021,487	\$6,972,258	\$5,201	\$6,977,459
8	Transmission	962,831	18	962,848	818,947	16	818,963
9	Distribution	1,761,781	(1,299)	1,760,482	1,562,270	(1,299)	1,560,971
10	General	647,933	(5,841)	642,092	564,483	(5,900)	558,584
11	Common	494,408	<u>(16)</u>	494,392	431,002		430,957
12	TOTAL Reserve for Depreciation	\$11,882,409	(\$1,108)	\$11,881,301	\$10,348,959	(\$2,026)	\$10,346,933
	Net Utility Plant in Service						
13	Production	\$6,676,946	(\$161,890)	\$6,515,055	\$5,785,788	(\$161,061)	\$5,624,727
14	Transmission	3,267,854	(18)	3,267,837	2,864,233	(16)	2,864,217
15	Distribution	3,278,650	(39,948)	3,238,703	2,866,538	(39,948)	2,826,590
16	General	648,135	(36,229)	611,906	565,231	(36,170)	529,061
17	Common	622,390	(8,559)	613,831	542,540	(8,531)	534,009
18	Net Utility Plant in Service	\$14,493,976	(\$246,644)	\$14,247,332	\$12,624,329	(\$245,725)	\$12,378,604
19	Utility Plant Held for Future Use	\$0	\$0	\$0	\$0	\$0	\$0
20	Construction Work in Progress	\$673,620	(\$143,159)	\$530,460	\$579,993	(\$143,159)	\$436,833
21	Less: Accumulated Deferred Income Taxes	\$2,454,842	\$17,754	\$2,472,596	\$2,160,968	\$17,137	\$2,178,105
22	Cash Working Capital	(\$180,242)	\$10,425	(\$169,816)	(\$161,577)	\$9,185	(\$152,392)
	Other Rate Base Items:						
23	Materials and Supplies	\$177,586	\$0	\$177,586	\$154,701	\$0	\$154,701
24	Fuel Inventory	80,448	0	80,448	69,767	0	69,767
25	Non-Plant Assets & Liabilities	79,949	31,703	111,652	66,154	31,703	97,858
26	Customer Advances	(8,779)		(8,779)	(7,200)		(7,200)
27	Interest on Customer Deposits	(28,391)		(28,391)	(28,273)		(28,273)
28	Prepaids and Other	79,730	0	79,730	69,357	0	69,357
29	Regulatory Amortizations	0	99,738	99,738	0	90,221	90,221
33	Total Other Rate Base Items	\$380,542	\$131,441	\$511,984	\$324,505	\$121,925	\$446,430
34	Total Average Rate Base	\$12,913,054	(\$265,691)	\$12,647,363	\$11,206,282	(\$274,912)	\$10,931,371

⁽¹⁾ Revenues and expenses for riders have been included where applicable.

RATE BASE SCHEDULES

Detailed Rate Base Components (\$000's)

		Adjuste Plan Y 2023	'ear	Adjusted (1) Plan Year 2024		
Line <u>No.</u>	<u>Description</u>	Total Utility (A)	Minnesota Jurisdiction (B)	Total Utility (C)	Minnesota <u>Jurisdiction</u> (D)	
	Electric Plant as Booked					
1	Production	\$14,515,299	\$12,543,687	\$14,790,684	\$12,749,709	
2	Transmission	4,454,690	3,878,352	4,671,872	4,067,600	
3	Distribution	5,413,277	4,744,230	5,842,133	5,124,628	
4	General	1,418,735	1,229,875	1,577,084	1,365,201	
5	Common	1,275,065	1,109,541	1,393,852	1,213,087	
6	TOTAL Utility Plant in Service	\$27,077,065	\$23,505,685	\$28,275,624	\$24,520,225	
	Reserve for Depreciation					
7	Production	\$8,159,216	\$7,096,188	\$8,667,015	\$7,535,471	
8	Transmission	1,035,217	881,905	1,111,727	948,447	
9	Distribution	1,854,878	1,644,203	1,965,625	1,741,690	
10	General	729,261	633,874	825,219	716,716	
11	Common	600,872	523,587	719,482	626,623	
12	TOTAL Reserve for Depreciation	\$12,379,444	\$10,779,757	\$13,289,067	\$11,568,947	
	Net Utility Plant in Service					
13	Production	\$6,356,082	\$5,447,500	\$6,123,669	\$5,214,238	
14	Transmission	3,419,473	2,996,448	3,560,145	3,119,153	
15	Distribution	3,558,400	3,100,027	3,876,508	3,382,938	
16	General	689,473	596,000	751,865	648,485	
17	Common	674,193	585,954	674,370	586,464	
18	Net Utility Plant in Service	\$14,697,621	\$12,725,928	\$14,986,557	\$12,951,278	
19	Utility Plant Held for Future Use	\$0	\$0	\$0	\$0	
20	Construction Work in Progress	\$609,104	\$506,554	\$729,505	\$616,842	
21	Less: Accumulated Deferred Income Taxes	\$2,373,175	\$2,087,146	\$2,229,238	\$1,954,203	
22	Cash Working Capital	(\$182,162)	(\$163,615)	(\$199,348)	(\$179,078)	
	Other Rate Base Items:					
23	Materials and Supplies	\$177,586	\$154,701	\$177,586	\$154,701	
24	Fuel Inventory	80,448	69,767	80,448	69,767	
25	Non-Plant Assets & Liabilities	139,263	123,255	167,376	148,557	
26	Customer Advances	(8,779)	(7,200)	(8,779)	(7,200)	
27	Interest on Customer Deposits	(28,391)	(28,273)	(28,391)	(28,273)	
28	Prepaids and Other	82,376	71,669	86,281	75,069	
29	Regulatory Amortizations	89,049	80,047	79,183	70,696	
30	Total Other Rate Base Items	\$531,552	\$463,965	\$553,704	\$483,317	
31	Total Average Rate Base	\$13,282,940	\$11,445,687	\$13,841,179	\$11,918,156	

⁽¹⁾ Revenues and expenses for riders have been included where applicable.

COMPARISON OF DETAILED RATE BASE COMPONENTS

Test Year Ending December 31, 2022 (\$000's)

Proposed	Test	Year	2022
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			Total Utility			Minnesota Jurisdiction *		
Line <u>No.</u>	<u>Description</u>	Unadjusted (A)	Adjustments (B)	<u>Total</u> (A) + (B)	<u>Unadjusted</u> (D)	Adjustments (E)	Total (D) + (E)	
	Construction Work in Progress							
1	Production	\$407,288	(\$125,707)	\$281,581	\$354,012	(\$125,707)	\$228,305	
2	Transmission	59,456	(1,202)	58,255	51,731	(1,202)	50,530	
3	Distribution	67,351	(3,334)	64,017	52,628	(3,334)	49,294	
4	General	85,761	(12,087)	73,674	74,756	(12,087)	62,669	
5	Common	53,764	(829)	52,935	46,864	(829)	46,036	
6	TOTAL Construction Work In Progress	\$673,620	(\$143,159)	\$530,460	\$579,993	(\$143,159)	\$436,833	

Plan Year 2023

		Total Utility			Minnesota Jurisdiction *		
Line <u>No.</u>	<u>Description</u>	Unadjusted (A)	Adjustments (B)	<u>Total</u> (A) + (B)	Unadjusted (D)	Adjustments (E)	Total (D) + (E)
	Construction Work in Progress						
7	Production	\$451,780	(\$149,874)	\$301,906	\$392,592	(\$149,874)	\$242,718
8	Transmission	103,751	(4,459)	99,292	90,296	(4,459)	85,837
9	Distribution	82,698	31	82,729	71,083	31	71,114
10	General	105,231	(17,611)	87,620	91,755	(17,611)	74,144
11	Common	37,537	<u>20</u>	37,557	32,721	20	32,741
12	TOTAL Construction Work In Progress	\$780,997	(\$171,893)	\$609,104	\$678,447	(\$171,893)	\$506,554

Plan Year 2024

			Total Utility		Minnesota Jurisdiction *		
Line <u>No.</u>	<u>Description</u>	Unadjusted (A)	Adjustments (B)	<u>Total</u> (A) + (B)	<u>Unadjusted</u> (D)	Adjustments (E)	Total (D) + (E)
	Construction Work in Progress						
13	Production	\$522,318	(\$157,622)	\$364,696	\$453,767	(\$157,622)	\$296,145
14	Transmission	173,088	(8,562)	164,526	150,616	(8,562)	142,054
15	Distribution	76,832	17	76,849	72,695	17	72,712
16	General	108,203	(13,248)	94,955	94,351	(13,248)	81,103
17	Common	28,460	<u>20</u>	28,480	24,809	<u>20</u>	24,829
18	TOTAL Construction Work In Progress	\$908,900	(\$179,395)	\$729,505	\$796,237	(\$179,395)	\$616,842

 $^{(\}mbox{\ensuremath{^{*}}})$ See Volume 3, Rate Base Section, Schedule E for allocation factors.

COMPARISON OF DETAILED RATE BASE COMPONENTS

Test Year Ending December 31, 2022 (\$000's)

Proposed Test Year 2022

Lina			Total Utility		Minnes	ota Jurisdicti	on *
Line No.	Description	Unadjusted A	djustments		Unadjusted A	djustments	
		(A)	(B)	<u>Total</u> (A) + (B)	(D)	(E)	Total (D) + (E)
	Accumulated Deferred Income Taxes						
1	Production	\$1,425,020	\$6,691	\$1,431,711	\$1,236,500	\$6,898	\$1,243,398
2	Transmission	850,355	85	850,440	748,342	86	748,427
3	Distribution	670,112	663	670,775	583,974	685	584,659
4	General	88,368	(2,141)	86,227	77,169	(2,126)	75,043
5	Common	76,948	(511)	76,437	67,082	(504)	66,578
6	Net Operating Loss (NOL)	(692,158)	4,861	(687,296)	(584,411)	3,992	(580,419)
7	Non-Plant Related	36,196	8,106	44,302	32,313	8,106	40,419
8	TOTAL Accum Deferred Income Taxes	\$2,454,842	\$17,754	\$2,472,596	\$2,160,968	\$17,137	\$2,178,105

Plan Year 2023

			Total Utility		Minnes	sota Jurisdicti	on *
Line <u>No.</u>	<u>Description</u>	Unadjusted (A)	Adjustments (B)	<u>Total</u>	Unadjusted (D)	Adjustments (E)	Total
				(A) + (B)			(D) + (E)
	Accumulated Deferred Income Taxes						
9	Production	\$1,509,692	(\$24,183)	\$1,485,509	\$1,310,010	(\$24,019)	\$1,285,991
10	Transmission	861,088	380	861,468	757,628	425	758,053
11	Distribution	668,497	(246)	668,250	582,466	(177)	582,288
12	General	91,994	(3,681)	88,313	80,298	(3,614)	76,684
13	Common	79,677	(1,179)	78,498	69,443	(1,146)	68,296
14	Net Operating Loss (NOL)	(882,465)	7,467	(874,998)	(752,041)	6,243	(745,797)
15	Non-Plant Related	57,609	8,526	66,135	53,104	8,526	61,630
16	TOTAL Accum Deferred Income Taxes	\$2,386,092	(\$12,917)	\$2,373,175	\$2,100,908	(\$13,762)	\$2,087,146

Plan Year 2024

			Total Utility		Minnes	sota Jurisdicti	on *
Line <u>No.</u>	<u>Description</u>	Unadjusted (A)	Adjustments (B)	<u>Total</u> (A) + (B)	Unadjusted A	Adjustments (E)	Total (D) + (E)
	Accumulated Deferred Income Taxes						
17	Production	\$1,550,109	(\$64,332)	\$1,485,777	\$1,346,313	(\$66,253)	\$1,280,060
18	Transmission	876,107	(2,785)	873,322	769,887	(1,485)	768,402
19	Distribution	670,657	(2,988)	667,669	584,146	(2,451)	581,696
20	General	99,764	(6,780)	92,984	86,695	(6,113)	80,581
21	Common	80,920	(1,639)	79,281	70,641	(1,731)	68,911
22	Net Operating Loss (NOL)	(1,059,719)	9,975	(1,049,743)	(908,571)	8,422	(900,149)
23	Non-Plant Related	71,518	8,430	79,948	66,272	8,430	74,702
24	TOTAL Accum Deferred Income Taxes	\$2,289,355	(\$60,117)	\$2,229,238	\$2,015,384	(\$61,181)	\$1,954,203

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

RATE BASE ADJUSTMENT SCHEDULES
2022 Unadjusted Test Year walk forward to Final Adjusted Test Year
(\$000s)

				Bridge - U	Inadjusted					Adjustments						Amort	izations				Ric	iers	Seco	ndary Calcula	tions	
Line No.	NSPM - 11 Bridge by Report Label	Unadjusted w/o NOL & 199 at Last Authorized	ADIT Prorate for IRS	ADIT Prorate NOL	Cash Working Capital	Net Operating Loss	Total Unadjusted at Last Authorized	Depreciatio n Study: Remaining Life	Depreciatio n Study: TD&G	Elec Battery Reserve	EOL Nuclear Fuel	Pension: Extend Deferral	Aurora	Bis Rider	Credit Rate Chg	Income Tax Tracker	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Sherco 3 Depr Deferral	Rider: RES	Rider: TCR	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Total
	Work Paper Reference							WP-A21	WP-A22	WP-A23	WP-A24	WP-A31	WP-A34	WP-A35	WP-A36	WP-A37	WP-A38	WP-A39	WP-A40	WP-A42	WP-A44	WP-A45	WP-A46	WP-A47	WP-A48	
	Column Number	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)
(1)																										
(2)	Plant as booked																									
(3)	Production	12,758,046					12,758,046														(155,860)					12,602,186
(4)	Transmission	3,683,180					3,683,180																			3,683,180
(5)	Distribution	4,428,808					4,428,808															(41,246)				4,387,561
(6)	General	1,129,714					1,129,714															(42,070)				1,087,644
(7)	Common	973,541					973,541															(8,575)				964,966
(8)	Total Utility Plant in Service	22,973,289					22,973,289														(155,860)					22,725,537
(9)	rotal other rane in service	22,373,203					11,373,103														(155,000)	(52,052)				LL, , LJ, JJ,
(10)	Reserve for Depreciation																									
(11)	Production	6,972,258					6,972,258	6,301		133	(951)										(283)					6,977,459
								0,301			(951)										(283)					
(12)	Transmission	818,947					818,947		16																	818,963
(13)	Distribution	1,562,270					1,562,270		(16)													(1,282)				1,560,971
(14)	General	564,483					564,483		397													(6,297)				558,584
(15)	Common	431,002					431,002		192													(237)				430,957
(16)	Total Reserve for Depreciation	10,348,959					10,348,959	6,301	589	133	(951)										(283)	(7,816)				10,346,933
(17)																										
(18)	Net Utility Plant																									
(19)	Production	5,785,788					5,785,788	(6,301)		(133)	951										(155,577)					5,624,727
(20)	Transmission	2,864,233					2,864,233		(16)																	2,864,217
(21)	Distribution	2,866,538					2,866,538		16													(39,964)				2,826,590
(22)	General	565,231					565,231		(397)													(35,773)				529,061
(23)	Common	542,540					542,540		(192)													(8,338)				534,009
(24)	Net Utility Plant in Service	12,624,329					12,624,329	(6,301)	(589)	(133)	951										(155,577)	(84,076)				12,378,604
(25)																										
(26)	Utility Plant Held for Future Use																									
(27)																										
(28)	Construction Work in Progress	579,993					579,993														(125,707)	(17,452)				436,833
(29)																										
(30)	Less: Accumulated Deferred Income Taxes	2,565,260	(4,220)	817		(420,197)	2,141,660	(1,764)	(165)	(37)	266	8,877							13,952	2,566	(8,655)	(2,721)	826		23,300	2,178,105
(31)																										
(32)	Other Rate Base Items																									
(33)	Cash Working Capital				(161,376)		(161,376)																	8,984		(152,392)
(34)	Materials and Supplies	154,701			(,,		154,701																	-,		154,701
(35)	Fuel Inventory	69,767					69,767																			69,767
(36)	Non Plant Assets and Liabilities	66,154					66,154					31,703														97,858
(37)	Customer Advances	(7,200)					(7,200)					31,703														(7,200)
(38)		(28,273)					(28,273)																			(28,273)
	Customer Deposits	69,357																								69,357
(39)	Prepayments	09,357					69,357						2.654	2.178	(256)	5.036	342	39.849	34.128	6.289						
(40)	Regulatory Amortizations														,	.,,,,,,										90,221
(41) (42)	Total Other Rate Base	324,505			(161,376)		163,129					31,703	2,654	2,178	(256)	5,036	342	39,849	34,128	6,289				8,984		294,039
(42)	Total Average Rate Base	10,963,567	4,220	(817)	(161,376)	420,197	11,225,791	(4,537)	(424)	(96)	685	22,826	2,654	2,178	(256)	5,036	342	39,849	20,177	3,723	(272,630)	(98,807)	(826)	8,984	(23,300)	10,931,371

(\$000s)

		Bridge - Unadjusted							Adjustments						An	nortizations				Rid	iers	Se	condary Calculati	ons		
Line No.		Unadjusted w/o NOL & 199 at Last Authorized	ADIT Prorate for IRS	ADIT Prorate NOL	Cash Working Capital	Net Operating Loss	Total Unadjusted at Last Authorized	Depreciation Study: Remaining Life	Depreciation Study: TD&G	Elec Battery Reserve	EOL Nuclear Fuel	Pension: Extend Deferral	Aurora	Bis Rider	Credit Rate Chg	Income Tax Tracker	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Sherco 3 Depr Deferral	Rider: RES	Rider: TCR	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Total
	Work Paper Reference							WP-A21	WP-A22	WP-A23	WP-A24	WP-A31	WP-A34	WP-A35	WP-A36	WP-A37	WP-A38	WP-A39	WP-A40	WP-A42	WP-A44	WP-A45	WP-A46	WP-A47	WP-A48	
	Column Number	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)
(1)																										
	Plant as booked																									
(3)	Production	13,000,884					13,000,884														(457,197)					12,543,687
(4)	Transmission	3,878,352					3,878,352																			3,878,352
(5)	Distribution	4,871,294					4,871,294															(127,064)				4,744,230
(6)	General	1,282,698					1,282,698															(52,823)				1,229,875
(7)	Common	1,124,830					1,124,830															(15,289)				1,109,541
	Total Utility Plant in Service	24,158,059					24,158,059														(457,197)	(195,176)				23,505,685
(9)																										
	Reserve for Depreciation																									
(11)	Production	7,097,393					7,097,393	9,511		387	(2,913)										(8,190)					7,096,188
(12)	Transmission	881,857					881,857		47																	881,905
(13)	Distribution	1,649,717					1,649,717		(36)													(5,478)				1,644,203
(14)	General	644,153					644,153		1,384													(11,662)				633,874
(15)	Common	524,707					524,707		619													(1,739)				523,587
(16) (17)	Total Reserve for Depreciation	10,797,827					10,797,827	9,511	2,014	387	(2,913)										(8,190)	(18,879)				10,779,757
(18)	Net Utility Plant																									
(19)	Production	5,903,491					5,903,491	(9,511)		(387)	2,913										(449,007)					5,447,500
(20)	Transmission	2,996,495					2,996,495		(47)																	2,996,448
(21)	Distribution	3,221,577					3,221,577		36													(121,586)				3,100,027
(22)	General	638,545					638,545		(1,384)													(41,161)				596,000
(23)	Common	600,123					600,123		(619)													(13,550)				585,954
(24) I (25)	Net Utility Plant in Service	13,360,231					13,360,231	(9,511)	(2,014)	(387)	2,913										(449,007)	(176,297)				12,725,928
(26)	Utility Plant Held for Future Use																									
(27)																										
(28)	Construction Work in Progress	678,447					678,447														(149,874)	(22,019)				506,554
(29)																										
(30) I (31)	Less: Accumulated Deferred Income Taxes	2,856,528	(3,169	(410))	(788,719	2,064,230	(2,663)	(564)	(108)	816	8,842							12,773	2,361	(37,933)	(5,199)	1,671		42,921	2,087,146
(32)	Other Rate Base Items																									
	Cash Working Capital				(173,447)		(173,447)																	9,832		(163,615
(34)	Materials and Supplies	154,701 69,767					154,701																			154,701 69,767
(35)	Fuel Inventory						69,767																			
	Non Plant Assets and Liabilities	91,677					91,677					31,578														123,255
(37)	Customer Advances	(7,200)					(7,200)																			(7,200
	Customer Deposits	(28,273)					(28,273)																			(28,273
(39)	Prepayments	71,669					71,669						072	4 207	(05)	2 022	205	27.000	24.244	5 705						71,669 80,047
(40)	Regulatory Amortizations	252.7.7			6000 0000		470.577					24.5	873	1,307	(85)					5,786				0		
(41)	Total Other Rate Base	352,340			(173,447)		178,893					31,578	873	1,307	(85)	3,022	205	37,695	31,244	5,786				9,832		300,350
	Total Average Rate Base	11,534,490	3,169	410	(173,447)	788,719	12,153,341	(6,848)	(1,450)	(279)	2,097	22,736	873	1,307	(85)	3,022	205	37,695	18,472	3,425	(560,948)	(193,117)	(1,671)	9,832	(42,921)	11,445,687
()		,, +30	-,203	*10	(=,=,447)	,/20	,,544	(4,440)	(-,.50)	(-73)	-,227	,. 30	373	2,307	,007	-,	203	,000	,-/.2	-, 12.5	(222,540)	(,)	(2,072)	-,032	(,524)	22, , 007

			Bridge - Unadjusted							Adjustments	;					Amorti	zations				Ric	iers	Seco	ndary Calculat	ions	
Line No.	NSPM - 11 Bridge by Report Label	Unadjusted w/o NOL &	ADIT Prorate for	ADIT	Cash Working	Net Operating	Total Unadjusted	Depreciatio n Study:	Depreciatio n Study:	Elec Battery	EOL Nuclear	Pension: Extend	Aurora	Bis Rider	Credit Rate	Income Tax	LED Street	NOL ADIT	PI EPU	Sherco 3 Depr	Rider: RES	Rider: TCR	ADIT Prorate for	Cash	Net Operating	Total
		199 at Last Authorized	IRS	Prorate NOL	Capital	Loss	at Last Authorized	Remaining Life	TD&G	Reserve	Fuel	Deferral			Chg	Tracker	Lighting	ARAM	Recovery	Deferral			IRS	Capital	Loss	
	Work Paper Reference							WP-A21	WP-A22	WP-A23	WP-A24	WP-A31	WP-A34	WP-A35	WP-A36	WP-A37	WP-A38	WP-A39	WP-A40	WP-A42	WP-A44	WP-A45	WP-A46	WP-A47	WP-A48	
	Column Number	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)
(1)																										
(2)	Plant as booked																									
(3)	Production	13,458,101					13,458,101														(708,392)					12,749,709
(4)	Transmission	4,067,600					4,067,600																			4,067,600
(5)	Distribution	5,341,760					5,341,760															(217,131)				5,124,628
(6)	General	1,439,171					1,439,171															(73,970)				1,365,201
(7)	Common	1,228,376					1,228,376															(15,289)				1,213,087
(8)	Total Utility Plant in Service	25,535,007					25,535,007														(708,392)	(306,390)				24,520,225
(9)																										
(10)	Reserve for Depreciation																									
(11)	Production	7,550,436					7,550,436	12,139		622	(4,999)										(22,727)					7,535,471
(12)	Transmission	948,366					948,366		81																	948,447
(13)	Distribution	1,755,809					1,755,809		(27)													(14,093)				1,741,690
(14)	General	731,916					731,916		2,682													(17,883)				716,716
(15)	Common	630,016					630,016		1,148													(4,541)				626,623
(16)	Total Reserve for Depreciation	11,616,543					11,616,543	12,139	3,885	622	(4,999)										(22,727)					11,568,947
(17)																										
(18)	Net Utility Plant																									
(19)	Production	5,907,665					5,907,665	(12,139)		(622)	4,999										(685,665)					5,214,238
(20)	Transmission	3,119,234					3,119,234		(81)																	3,119,153
(21)	Distribution	3,585,950					3,585,950		27													(203,038)				3,382,938
(22)	General	707,255					707,255		(2,682)													(56,087)				648,485
(23)	Common	598,360					598,360		(1,148)													(10,748)				586,464
(24)	Net Utility Plant in Service	13,918,464					13,918,464	(12,139)	(3,885)	(622)	4,999										(685,665)	(269,873)				12,951,278
(25)																										
(26)	Utility Plant Held for Future Use																									
(27)	,																									
(28)	Construction Work in Progress	796,237					796,237														(157,622)	(21,773)				616,842
(29)		,																			(,,	(==))				,
(30)	Less: Accumulated Deferred Income Taxes	2,925,918	(1,474)	(489)		(053 204)	1,970,660	(3,399)	(1,088)	(174)	1,400	8,630							11,594	2,156	(82,645)	(8,057)	1,982		53,145	1,954,203
(31)		2,020,020	(-),	()		(000)201)	-,,	(0,000)	(-,,	()	-,	-,							,	-,	(0=,0.0)	(0)-0.7	-,			-,,
(32)	Other Rate Base Items																									
(33)	Cash Working Capital				(189,576)		(189,576)																	10,498		(179,078)
(34)	Materials and Supplies	154,701			(103,370)		154,701																	10,430		154,701
(35)	Fuel Inventory	69,767					69,767																			69,767
(36)	Non Plant Assets and Liabilities	117,737					117,737					30,820														148,557
(37)	Customer Advances	(7,200)					(7,200)					50,020														(7,200)
(38)	Customer Deposits	(28,273)					(28,273)																			(28,273)
(39)	Prepayments	75,069					75,069																			75,069
(40)	Regulatory Amortizations	73,009					73,009							436		1,007	68	35,541	28,360	5,283						70,696
(40)	Total Other Rate Base	381,801			(189,576)		192,225					30,820		436		1,007	68	35,541	28,360	5,283				10,498		304,239
(41)	Total Other hate base	381,801			(109,570)		192,225					30,820		430		1,007	08	33,341	28,300	5,283				10,498		304,239
(43)	Total Average Rate Base	12,170,585	1,474	489	(189,576)	953,294	12,936,266	(8,740)	(2,797)	(448)	3,599	22,190		436		1,007	68	35,541	16,766	3,127	(760,642)	(283,589)	(1,982)	10,498	(53,145)	11,918,156

Total Income Taxes

Docket No. E002/GR-21-630 Exhibit___(BCH-1), Schedule 11a Page 1 of 2

2022 Una (\$000s)	ljusted Test Year walk forward to Final Adjusted	d Test Year																				
(44444)				Bridge - U	Inadjusted			Precedential							Adju	stment						
Line No.		Unadjusted	ADIT		Cash		Total		CIP			Depreciatio					Nobles		Pension:	Pension:	Pension:	
Line No.		w/o NOL & 199 at Last Authorized	Prorate for IRS	ADIT Prorate NOL	Working Capital	Net Operating Loss	Unadjusted at Last Authorized	Precedential Adjustments	Approved Program Levels	Credit Card AutoPay	Decommissi oning	n Study: Remaining Life	Depreciatio n Study: TD&G	Elec Battery Reserve	EOL Nuclear Fuel	Incentive Compensati on	Amounts over CON	Pension: Deferred Amort	Discount Rate	Extend Deferral	Retiree Medical	Transmission n ROE
	Workpaper Reference							WP-A1 - WP-A17		WP-A19	WP-A20	WP-A21	WP-A22	WP-A23	WP-A24	WP-A25 - WP- A27	WP-A28	WP-A29	WP-A30	WP-A31	WP-A32	WP-A33
(1)		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)
(2)	Operating Revenues																					
(3)	Retail Revenue	3,341,841					3,341,841		(33,163)													
(4)	Interdepartmental	380					380															
(5)	Other Operating	732,890					732,890	9,089				537	5	42	(302)		159					(12,583
(6)	Total Revenue	4,075,111					4,075,111	9,089	(33,163)			537	5	42	(302)		159					(12,583
(7)	5																					
(8)	Expenses Operating Expenses																					
(10)	Fuel & Purchased Energy	1,039,927					1,039,927															
(11)	Power Production	619,941					619,941	(3,608)							(1,902)							
(12)	Transmission	355,757					355,757															(2,058
(13)	Distribution	125,185					125,185															
(14)	Customer Accounting	60,878					60,878															
(15)	Customer Service and Information	163,576					163,576	400	(33,163)													
(16) (17)	Sales, Econ Dev, & Other Administrative and General	7,439 252,960					7,439 252,960	102 (21.768)								6,126			(293)		(240)	
(18)	Total Operating Expenses	2,625,663					2,625,663	(25,274)	(33,163)						(1,902)				(293)		(240)	(2,058
(19)		_,,					_,,	(==)=,	(00,200)						(-,,	0,220			()		(=/	(=/===
(20)	Depreciation	818,735					818,735				(472)	3,686	1,178	266								
(21)	Amortization	43,366					43,366											5,302				
(22)																						
(23)	Taxes																					
(24)	Property Deferred Income Tax and ITC	203,297 119,438				(192,196)	203,297					(1,032)	(330)	(75)	532					53		
(26)	Federal and State Income Tax	(283,923)	(27)	5	1.044	189,868					136		(330)	13	(91)	(1,761)	46	(1,524)	84	(202)	69	(3,025
(27)	Payroll and Other	26,736	(27)	,	1,044	103,000	26,736	(37)			130	104	-	13	(91)	(1,701)	40	(1,324)	04	(202)	03	(3,023
(28)	Total Taxes	65,548	(27	5	1,044	(2,328)	-,	9,850			136	(848)	(326)	(62)	441	(1,761)	46	(1,524)	84	(149)	69	(3,025
(29)																						
(30)	Total Expenses	3,553,311	(27)	5	1,044	(2,328)	3,552,005	(15,424)	(33,163)		(336)	2,837	852	204	(1,460)	4,365	46	3,778	(209)	(149)	(171)	(5,083
(31)																						
(32)	Allowance for Funds Used During Construction	33,212					33,212															
(34)	Net Income	555,011	27	(5)	(1.044)	2,328	556,317	24,513			336	(2,301)	(847)	(162)	1,159	(4,365)	113	(3,778)	209	149	171	(7,500
(35)				(4)	(2,0)	-,	***************************************	- ,,			-	(-))	(0)	(202)	-,	(1,000)		(0)0)				(1)000
(36)	Calculation of Revenue Requirements																					
(37)	Rate Base	10,963,567	4,220	(817)	(161,376)	420,197	11,225,791					(4,537)	(424)	(96)	685					22,826		
(38)	Required Operating Income	768,546	296	(57)								(318)	(30)	(7)						1,600		
(39)	Operating Income	555,011	27	(5)				24,513			336		(847)			(4,365)		(3,778)		149	171	(7,500
(40)	Income Deficiency	213,535	269	(52)	(10,269)	27,128	230,611	(24,513) (34,401)			(336)	1,983	817	155	(1,111)	4,365	(113)	3,778	(209)	1,451	(171)	7,500
(41) (42)	Revenue Deficiency	299,664	377	(73)	(14,411)	38,070	323,628	(34,401)			(472)	2,782	1,147	218	(1,558)	6,126	(159)	5,302	(293)	2,036	(240)	10,525
(42)	Calculation of Income Taxes																					
(44)	Operating Revenue	4,075,111					4.075.111	9.089	(33.163)			537	5	42	(302)		159					(12,583
(45)	-Operating Expense	2,625,663					2,625,663	(25,274)	(33,163)						(1,902)				(293)		(240)	
(46)	-Amortization	43,366					43,366											5,302				
(47)	-Taxes Other then Income	349,471				(192,196)	157,275	(37)				(1,032)	(330)	(75)	532					53		
(48)	Operating Income Before Adjs	1,056,612				192,196		34,401				1,569	335	117	1,067	(6,126)	159	(5,302)	293	(53)	240	(10,525
(49)	Additions to Income	283,176				(192,196)						(1,032)	(330)	(75)	(1,369)					53		
(50)	Deductions from Income	1,490,314 246,680	0.5	(18)	(2.624)	(79,424) 9,454					(472)		(***)	(2)						188 514		
(51) (52)	Debt Synchonization State Taxable Income	(397,207)	95 (95)		(3,631) 3,631	9,454 69,970		34.401			472	(102) 639	(10) 14	(2) 45	15 (317)	(6,126)	159	(5,302)	293	(702)	240	(10,525
(52)	State Income Tax Before Credits	(38,926)	(9)		356	6,857	(31,721)				4/2		14	45	(317)		16	(5,302)		(69)		(1,031
(54)	State Tax Credits	(946)	(5)		230	946		2,371			40	33	•		(31)	(200)	20	(320)		,00)		(2,03)
(55)	Federal Tax Deductions																					
(56)	Federal Taxable Income	(357,334)	(86)		3,275	62,167					426	576	13	40	(286)	(5,526)		(4,782)		(633)	217	(9,494
(57)	Federal Income Tax Before Credits	(75,040)	(18)	3	688	13,055		6,516			89	121	3	8	(60)	(1,160)	30	(1,004)	56	(133)	46	(1,994
(58)	Federal Tax Credits	(169,010)				169,010																

9,887

(91) (1,761)

46 (1,524)

(283,923) (27) 5 1,044 189,868 (93,033)

(58)

(59)

Federal Tax Credits

Total Income Taxes

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022 Unadjusted Test Year walk forward to Final Adjusted Te

2022 Unac (\$000s)	ljusted Test Year walk forward to Final Adjusted Te	!																		
											1	Rider Remova	ls		Secondary 0	Calculations			Fuel Adj	ustment
Line No.		Aurora	Bis Rider	Credit Rate Chg	Income Tax Tracker	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Rate Case Expenses	Sherco 3 Depr Deferral	Renewable Connect	Rider: RES	Rider: TCR	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
	Workpaper Reference	WP-A34 (22)	WP-A35 (23)	WP-A36 (24)	WP-A37 (25)	WP-A38 (26)	WP-A39 (27)	WP-A40 (28)	WP-A41 (29)	WP-A42 (30)	WP-A43 (31)	WP-A44 (32)	WP-A45 (33)	WP-A46 (34)	WP-A47 (35)	WP-A49 (36)	WP-A48 (37)	(38)	(39)	(40)
(1)		(22)	(23)	(24)	(23)	(25)	(27)	(20)	(23)	(50)	(32)	(32)	(33)	(34)	(33)	(30)	(37)	(30)	(33)	(40)
(2)	Operating Revenues Retail Revenue											(26.151)	(26,593)					3,255,934	(849.346)	2,406,588
(4)	Interdepartmental											(26,151)	(26,593)					3,255,934	(849,346)	2,406,588
(5)	Other Operating							1,514			(35,294)		(100,243)					595,815	(146,440)	449,375
(6)	Total Revenue							1,514			(35,294)	(26,151)	(126,836)					3,852,129	(995,786)	2,856,343
(7)	Expenses																			
(9)	Operating Expenses																			
(10)	Fuel & Purchased Energy										(35,993)							1,003,935	(990,006)	13,928
(11)	Power Production										4,989	(325)						619,095		619,095
(12)	Transmission												(96,102)					257,597		257,597
(13) (14)	Distribution Customer Accounting												(4,382) (9,741)					120,803 51,137		120,803 51,137
(15)	Customer Service and Information										(175)		(5,742)					130,239		130,239
(16)	Sales, Econ Dev, & Other																	7,541		7,541
(17)	Administrative and General																	236,784		236,784
(18) (19)	Total Operating Expenses										(31,179)	(325)	(110,225)					2,427,130	(990,006)	1,437,124
(20)	Depreciation											(566)	(7,321)					815,505		815,505
(21)	Amortization	2,606	871	(170)	2,015	137	2,154	2,884	1,562	503								61,229	(5,780)	55,449
(22)																				
(23)	Taxes											(05)						202.240		202 240
(24) (25)	Property Deferred Income Tax and ITC							(1,179)		(205)		(86) (17,796)	(2,488)				27,560	203,210 (67,718)		203,210 (67,718)
(26)	Federal and State Income Tax	(766)	(264)	2	(612)	(42)	(258)		(449)	(24)	(1,183)		507	5	(58)	9,426	(27,799)	(97,637)		(97,637)
(27)	Payroll and Other																	26,699		26,699
(28) (29)	Total Taxes	(766)	(264)	2	(612)	(42)	(258)	(874)	(449)	(229)	(1,183)	(5,096)	(1,981)	5	(58)	9,426	(239)	64,555		64,555
(30)	Total Expenses	1,840	607	(169)	1,403	95	1,896	2,010	1,113	274	(32,362)	(5,987)	(119,528)	5	(58)	9,426	(239)	3,368,419	(995,786)	2,372,633
(32)	Allowance for Funds Used During Construction																	33,212		33,212
(34)	Net Income	(1,840)	(607)	169	(1,403)	(95)	(1,896)	(495)	(1,113)	(274)	(2,932)	(20,164)	(7,308)	(5)	58	(9,426)	239	516,922	(0)	516,922
(35)																				
(36)	Calculation of Revenue Requirements	2.554	2 470	(255)		242	20.040	20.477		2 722		(272 520)	(00.007)	(025)			(22.200)	40.004.074		40 004 074
(37)	Rate Base Required Operating Income	2,654 186	2,178 153	(256)	5,036 353	342 24	39,849 2,793	20,177 1.414		3,723 261		(272,630) (19,111)		(826) (58)	8,984 630	32,794	(23,300)	10,931,371 799,083		10,931,371 799,083
(39)	Operating Income	(1,840)	(607)	169	(1,403)	(95)	(1,896)	(495)	(1,113)	(274)	(2,932)	(20,164)	(7,308)	(5)	58	(9,426)	239	516,922		516,922
(40)	Income Deficiency	2,026	759	(187)	1,756	119	4,690	1,910	1,113	535	2,932	1,053	382	(53)	572	42,220	(1,872)	282,161		282,161
(41)	Revenue Deficiency	2,843	1,066	(262)	2,464	167	6,581	2,680	1,562	750	4,115	1,478	536	(74)	802	59,249	(2,628)	395,972		395,972
(42)	Coloridation of Income Torre																			
(43)	Calculation of Income Taxes Operating Revenue							1,514			(35,294)	(26.151)	(126.836)					3.852.129	(995.786)	2.856.343
(45)	-Operating Expense							-,			(31,179)	(325)	,,					2,427,130	(990,006)	1,437,124
(46)	-Amortization	2,606	871	(170)	2,015	137	2,154	2,884	1,562	503								61,229	(5,780)	55,449
(47)	-Taxes Other then Income							(1,179)		(205)		(17,882)	(2,488)				27,560	162,192		162,192
(48) (49)	Operating Income Before Adjs Additions to Income	(2,606)	(871)	170 (170)	(2,015)	(137)	(2,154) 2,154	(191) 1,705	(1,562)	(298) 298	(4,115)	(7,944) (28,390)	(14,123) (2,526)				(27,560) 27,560	1,201,578 88,857	(0)	1,201,578 88,857
(50)	Deductions from Income			(1/0)			2,154	1,/05		298		(74,477)					79,424	1,399,364		1,399,364
(51)	Debt Synchonization	60	49	(6)	113	8	897	454		84		(6,134)		(19)	202	(32,794)	(524)	213,162		213,162
(52)	State Taxable Income	(2,666)	(920)		(2,128)		(897)		(1,562)	(84)	(4,115)		1,763	19	(202)	32,794	(78,900)	(322,090)		(322,090)
(53)	State Income Tax Before Credits	(261)	(90)	1	(209)	(14)	(88)	104	(153)	(8)	(403)	4,339	173	2	(20)	3,214	(7,732)	(31,565)		(31,565)
(54) (55)	State Tax Credits Federal Tax Deductions																(946)	(946)		(946)
(56)	Federal Taxable Income	(2,405)	(830)	5	(1,919)	(130)	(809)	957	(1,409)	(76)	(3,712)	39,938	1,590	17	(182)	29,580	(70,222)	(289,580)		(289,580)
(57)	Federal Income Tax Before Credits	(505)	(174)	1	(403)			201	(296)	(16)	(779)		334	4	(38)	6,212	(14,747)	(60,812)		(60,812)

(42) (258) 305 (449)

(24) (1,183) 12,786

507

(58) 9,426 (27,799) (97,637)

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INCOME STATEMENT ADJUSTMENT SCHEDULES

2023 Unadjusted Test Year walk forward to Final Adjusted Test Year

(\$000s)

Second Part	(\$000s)																						
Part					Bridge - U	Jnadjusted			Precedential							Adj	ustment						
March Marc						,			. /cccucintial							1	1	1		1			1
Note			Unadjusted w/o					Total		CIP Approved			Depreciation					Nobles	Pension:		Pension:	Pension:	
Part	No.																						Transmission
Part			Last Authorized	IRS	NOL	Capital	Loss	Last Authorized	Adjustments	Levels	AutoPay	oning	Remaining Life	Study: TD&G	Reserve	Fuel	Compensation	CON	Amort	Discount Rate	Deferral	Medical	ROE
Part																	M/D A2E M/D						
Control Cont		Workpaper Reference																					
Part			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)
Martine Mart																							
Mathematical Math										(0.4.607)													
Mary										(31,687)													
Property									7.025				240		20	(202)							(42.500)
Part								-,	,	(24.607)													. ,,
Note		Total Revenue	4,097,372					4,097,372	7,835	(31,087)			348	5	30	(302)							(12,500)
Mathematical Mat		Evnoncos																					
Markenterlenge		•																					
Section Sect			1 040 915					1 040 915															
			,						(3.638)							(2.022)							
Second 11,73 11,									(3,030)							(2,022)							(1,989)
Common section 10,40																							(2,505)
Mathematical Math																							
Marke Mark										(31,687)													
Mathematic Mat									102														
10 10 10 10 10 10 10 10	(17)		259,009					259,009	(21,620)								6,374			(293)		(211	
Composition			2,678,776					2,678,776	(25,156)	(31,687)						(2,022)	6,374			(293)		(211	(1,989)
1. 1. 1. 1. 1. 1. 1. 1.	(19)																						
Property	(20)	Depreciation	874,995					874,995				(472)	2,733	1,673	242								
Second S	(21)	Amortization	37,404					37,404											5,302				
Page	(22)																						
Second	(23)	Taxes																					
Second processes 1968 1968 1969 19	(24)	Property	217,125					217,125															
Part	(25)	Deferred Income Tax and ITC	91,156				(177,804)	(86,648)					(765)	(468)	(68)	566					(123)		
No Total Face 10 10 10 10 10 10 10 1	(26)	Federal and State Income Tax	(308,590)	(20)	(3)	1,122	172,363	(135,128)	9,493			136	144	11	12	(101)	(1,832)		(1,524)	84	(21)	61	(3,021)
Part	(27)	Payroll and Other	27,474					27,474	(38)														
Decembe Dece	(28)	Total Taxes	27,165	(20)	(3)	1,122	(5,441)	22,823	9,455			136	(621)	(458)	(56)	466	(1,832)		(1,524)	84	(144)	61	(3,021)
1																							
Algorithm Algo		Total Expenses	3,618,340	(20)	(3)	1,122	(5,441)	3,613,998	(15,701)	(31,687)		(336)	2,112	1,215	186	(1,557)	4,542		3,778	(209)	(144)	(150)	(5,010)
Section Sect																							
All Network 10,000 10,00		Allowance for Funds Used During Construction	31,766					31,766															
Column C			E 4 0 700			(4.400)							(4.004)	(4.040)					(0.000)				/m .com
		Net income	510,798	20	3	(1,122)	5,441	515,141	23,536			336	(1,/64)	(1,210)	(151)	1,254	(4,542)		(3,778)	209	144	150	(7,490)
Regular of Departing Income 1,534,00 3,169 410 (173,447) 788,719 (2,153,841) 1,524,00 1,640 1,040																							
Regular Operating Income				2.450		(470.447)	200 240						(6.0.40)	(4.450)	(0.00)								
									22 526			226							(2.770)	300		450	(7.400)
Revenue Deficiency 41,875 28 37 15,489 69,955 472,661 23,030 472,030 472,030 472,030 472,030 472,030 472,030 472,030	,																						
(42) (43) (44) (45) (45) (46) (46) (47) (47) (47) (48) (4								,						-,					0,				
All Carbon Carb		nevenue sentienty	417,075	203	3,	(15,405)	03,333	472,001	(33,030)			(472)	1,002	1,550	204	(2,554)	0,574		3,302	(233)	2,033	(222,	10,511
Containing Revenue Contain		Calculation of Income Taxes																					
Composition			4 097 372					4 097 372	7 835	(31 687)			348	5	36	(302)							(12,500)
46 Amortization 37,404 137,951 37,004 157,951 38) 765 468 568 568 568 569 569 569 569 569 57 59 59 59 59 59 59 5													540	,	30					(293)		(211)	
Canonic Cano									(23,230)	(51,007)						(2,022)	0,574		5.302			(222)	(1,505)
49 Additions to Income 256,092 177,804 78,288 765 468 68 1,456 1,4	,						(177,804)		(38)				(765)	(468)	(68)	566			-,		(123)		
49 Additions to Income 256,092 177,804 78,288 765 468 68 1,456 1,4									33.030				1.113	473	104	1.154	(6.374)		(5.302)	293			(10,511)
Fig. Deductions from Income 1,450,864 39,879 1,490,743 1,490,743 1,490,743 1,490,743 1,490,743 1,490,743 1,490,743 1,490,743 1,490,743 1,490,743 1,490,743 1,590,743									,-==										,				,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,
Sil Debt Synchonization 259,526 71 9 (3,903) 17,746 273,450 (154) (33) (6) 47 (52) (45,641) (40,686) (71) (9) (3,903) (57,625) (462,663) (33,030) (472 502 38 42 (350) (6,374) (530) (530) (29) (7) (21) (10,541)												(472)		, .=/		. , , , , , ,							
State Taxable Income 408,860 (71) (9) 3,903 (57,625) 462,663 33,030 472 502 38 42 (350) (6,374) (5,302) 293 (72) 211 (10,503)				71	9	(3,903)								(33)	(6)	47							
(53) State Income Tax Before Credits (40,068) (7) (1) 382 (5,647) (45,341) 3,237 46 49 4 4 (34) (625) (520) 29 (7) 21 (1,0 (54) (54) (54) (54) (54) (54) (54) (54)									33,030			472							(5,302)	293			(10,511)
(54) State Tax Credits (946) 213 (733) (55) Federal Tax Deductions (56) Federal Tax Defunctions (57) Federal Tax Defunction Ta	(53)								3,237										(520)				
(5) Federal Tax Deductions (5) Federal Tax Deductions (5) Federal Tax Defunctions (5) Federal Tax Defunctions (6) Federal Tax Defunctions (7) Federal Tax Defunctions (7) Federal Tax Defunctions (7) Federal Tax Defunctions (7) Federal Tax Defunctions (8) Federal Tax Defunctions (8) Federal Tax Defunctions (19) 28) (8) Federal Tax Defunctions (19) 28) (18) 739 (10,560) (87,484) (6,256) (19) 739 (10,560) (19) 749 (10,560) (10																							
(57) Federal Income Tax Before Credits (77,248) (14) (2) 739 (10,960) (87,484) 6,256 89 95 7 8 (66) (1,207) (1,004) 55 (14) 40 (1,9 (58) Federal Tax Credits (190,328) 188,758 (1,570)	(55)	Federal Tax Deductions																					
(58) Federal Tax Credits (190,328) 188,758 (1,570)	(56)	Federal Taxable Income	(367,846)	(64)	(8)	3,520	(52,191)	(416,590)	29,793			426	453	34	38	(315)	(5,749)		(4,782)	264	(65)	190	(9,481)
	(57)	Federal Income Tax Before Credits	(77,248)	(14)	(2)	739	(10,960)	(87,484)	6,256			89	95	7	8	(66)	(1,207)		(1,004)	55	(14)	40	(1,991)
(59) Total Income Taxes (308,590) (20) (3) 1,122 172,363 (135,128) 9,493 136 144 11 12 (101) (1,832) (1,524) 84 (21) 61 (3,0	(58)	Federal Tax Credits	(190,328)				188,758	(1,570)															
	(59)	Total Income Taxes	(308,590)	(20)	(3)	1,122	172,363	(135,128)	9,493			136	144	11	12	(101)	(1,832)		(1,524)	84	(21)	61	(3,021)

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INCOME STATEMENT ADJUSTMENT SCHEDULES

2023 Unadjusted Test Year walk forward to Final /

(\$000s)		

(\$000s	T																-		1	
												Rider Removals			Secondary	y Calculations			Fuel Adj	ustment
Line No.		Aurora	Bis Rider	Credit Rate Chg	Income Tax Tracker	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Rate Case Expenses	Sherco 3 Depr Deferral	Renewable Connect	Rider: RES	Rider: TCR	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
	Workpaper Reference	WP-A34	WP-A35	WP-A36	WP-A37	WP-A38	WP-A39	WP-A40	WP-A41	WP-A42	WP-A43	WP-A44	WP-A45	WP-A46	WP-A47	WP-A49	WP-A48			
(4)		(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)	(31)	(32)	(33)	(34)	(35)	(36)	(37)	(38)	(39)	(40)
(1) (2)	Operating Revenues																			
(3)	Retail Revenue											(52,186)	(52,587)					3,214,449	(849,346)	
(4)	Interdepartmental										(35,294)		(98,363)					382 609,232	(147,719)	382
(5) (6)	Other Operating Total Revenue							1,386 1.386			(35,294)	(52,186)	(150,950)					3,824,063	(997,065)	461,512 2,826,998
(7)								_,			(//	(,,	(,,					-,	(,,	_,,
(8)	Expenses																			
(9) (10)	Operating Expenses Fuel & Purchased Energy										(35,993)							1,004,922	(991,327)	13,595
(11)	Power Production										5,073	(5,718)						640,427	(,,	640,427
(12)	Transmission												(92,835)					265,940		265,940
(13) (14)	Distribution Customer Accounting												(9,842) (15,299)					126,532 45.999		126,532 45,999
(15)	Customer Service and Information										(150)		(13,233)					133,653		133,653
(16)	Sales, Econ Dev, & Other																	8,297		8,297
(17) (18)	Administrative and General Total Operating Expenses										(31,069)	(5,718)	(117,977)					243,259 2,469,029	(991,327)	243,259 1,477,701
(19)	Total Operating Expenses										(31,003)	(3,710)	(117,377)					2,403,023	(331,327)	1,477,701
(20)	Depreciation											(15,250)	(14,806)					849,115		849,115
(21)	Amortization	2,606	871	(170)	2,015	137	2,154	2,884	1,562	503								55,267	(5,738)	49,530
(22)	Taxes																			
(24)	Property											(1,065)						216,060		216,060
(25)	Deferred Income Tax and ITC	(200	1050		(500)		(0.44)	(1,179)		(205)		(40,055)	(2,473)				11,684	(119,735)		(119,735)
(26) (27)	Federal and State Income Tax Payroll and Other	(755)	(259) 1	(599)	(41)	(244)	279	(449) (22)	(1,214)	51,270	(1,452)	11	(64	10,856	(11,066)	(85,432) 27,435		(85,432) 27,435
(28)	Total Taxes	(755)	(259) 1	(599)	(41)	(244)	(900)	(449) (227)	(1,214)	10,150	(3,925)	11	(64	10,856	618	38,329		38,329
(29)																				
(30)	Total Expenses	1,851	612	(170)	1,416	96	1,910	1,984	1,113	276	(32,284)	(10,817)	(136,708)	11	(64	10,856	618	3,411,739	(997,065)	2,414,674
(32)	Allowance for Funds Used During Construction																	31,766		31,766
(33)																				
(34)	Net Income	(1,851)	(612	170	(1,416)	(96)	(1,910)	(598)	(1,113) (276)	(3,011)	(41,369)	(14,242)	(11)	64	(10,856)	(618)	444,090	0	444,090
(36)	Calculation of Revenue Requirements																			
(37)	Rate Base	873	1,307		3,022	205	37,695			3,425		(560,948)	(193,117)				(42,921)	11,445,687		11,445,687
(38)	Required Operating Income Operating Income	61 (1,851)	92 (612		212 (1,416)	14 (96)	2,642 (1,910)		(1,113	240	(3,011)	(39,322) (41,369)	(13,537) (14,242)					833,246 444,090		833,246 444,090
(40)	Income Deficiency	1,913	704		1,628	110	4,553	1,893	1,113) (276) 516	3,011	2,047	705	(106)			(2,391)	389,156		389,156
(41)	Revenue Deficiency	2,684	988	(247)	2,284	155	6,389	2,656	1,562	724	4,225	2,872	989	(149)	878	58,603	(3,355)	546,123		546,123
(42)					·											·				_
(43) (44)	Calculation of Income Taxes Operating Revenue							1,386			(35,294)	(52,186)	(150,950)					3,824,063	(997,065)	2,826,998
(45)	-Operating Expense							1,500			(31,069)		(117,977)					2,469,029	(991,327)	
(46)	-Amortization	2,606	871	(170)	2,015	137	2,154		1,562									55,267	(5,738)	49,530
(47)	-Taxes Other then Income Operating Income Before Adjs	(2,606)	(871) 170	(2,015)	(137)	(2,154)	(1,179)	(1,562	(205)	(4,225)	(41,120) (5,348)	(2,473)				11,684	123,761 1,176,007	0	1,176,007
(48)	Additions to Income	(2,000)	(6/1	(170)	(2,013)	(137)	2,154		(1,502	298	(4,223)	(49,798)	(2,674)				11,684	38,605	0	38,605
(50)	Deductions from Income											(167,508)	(23,777)				(39,879)	1,258,667		1,258,667
(51) (52)	Debt Synchonization State Taxable Income	20 (2,626)	29 (901		68 (2,083)	5 (141)	848 (848)	416 971	(1,562	77) (77)	(4,225)	(12,621) 124,982	(4,345) (5,052)	(38)	221 (221			219,757 (263,813)		219,757 (263,813)
(52)	State Taxable Income State Income Tax Before Credits	(2,626)	(88)		(2,083)				(1,562		(4,225)		(495)		(22)			(25,854)		(25,854)
(54)	State Tax Credits																(213)	(946)		(946)
(55) (56)	Federal Tax Deductions Federal Taxable Income	(2,368)	(812) 2	(1,878)	(127)	(765)	875	(1,409) (70)	(3,811)	112,734	(4,557)	34	(200	34,069	37,055	(237,013)		(237,013)
(56)	Federal Taxable Income Federal Income Tax Before Credits	(2,368)	(812		(394)				(1,409				(4,557) (957)		(42			(49,773)		(49,773)
(58)	Federal Tax Credits		•	•								15,348					(22,637)	(8,859)		(8,859)
(59)	Total Income Taxes	(755)	(259) 1	(599)	(41)	(244)	279	(449) (22)	(1,214)	51,270	(1,452)	11	(64	10,856	(11,066)	(85,432)		(85,432)

Docket No. E002/GR-21-630
Exhibit___(BCH-1), Schedule 11c
Page 1 of 2

INCOME STATEMENT ADJUSTMENT SCHEDULES

2024 Unadjusted Test Year walk forward to Final Adjusted Test Year (5000s)

(\$000s)																						
				Bridge - U	nadjusted			Precedential							Adjus	stment						
Line No.		Unadjusted	ADIT		Cash	Net	Total		CIP			Depreciatio	Depreciatio			Incentive	Nobles	Pension:	Pension:	Pension:	Pension:	
Lille NO.		w/o NOL &	Prorate for	ADIT	Working	Operating	Unadjusted	Precedential	Approved	Credit Card	Decommissi	n Study:	n Study:	Elec Battery	EOL Nuclear	Compensati	Amounts	Deferred	Pension: Discount	Extend	Retiree	Transmissio
		199 at Last Authorized	IRS	Prorate NOL	Capital	Loss	at Last Authorized	Adjustments	Program Levels	AutoPay	oning	Remaining Life	TD&G	Reserve	Fuel	on	over CON	Amort	Rate	Deferral	Medical	n ROE
	Workpaper Reference					<u> </u>		WP-A1 - WP-A17	WP-A18	WP-A19	WP-A20	WP-A21	WP-A22	WP-A23	WP-A24	WP-A25 - WP-	WP-A28	WP-A29	WP-A30	WP-A31	WP-A32	WP-A33
	Workpaper reference	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	A27 (15)	(16)	(17)	(18)	(19)	(20)	(21)
(1)																						
(2)	Operating Revenues																					
(3)	Retail Revenue Interdepartmental	3,398,267 386					3,398,267 386		(57,117)													
(5)	Other Operating	757,173					757,173	6,632				286	5	31	(303)							(12,427)
(6)	Total Revenue	4,155,825					4,155,825	6,632	(57,117)			286	5	31	(303)							(12,427)
(7)																						
(8) (9)	Expenses Operating Expenses																					
(10)	Fuel & Purchased Energy	1,040,731					1.040.731															
(11)	Power Production	647,270					647,270	(3,771)							(2,151)							
(12)	Transmission	365,393					365,393															(1,915)
(13)	Distribution	137,882					137,882															
(14)	Customer Accounting	64,173					64,173			6,608												
(15) (16)	Customer Service and Information Sales, Econ Dev, & Other	190,972 8,760					190,972 8.760	102	(57,117)													
(17)	Administrative and General	267,378					267,378	(22,473)								6,671			(294)		(190)	
(18)	Total Operating Expenses	2,722,558					2,722,558	(26,142)	(57,117)	6,608					(2,151)				(294)		(190)	(1,915)
(19)																						
(20)	Depreciation	940,401					940,401				(472)	2,525	2,069	227								
(21) (22)	Amortization	39,219					39,219											5,302				
(22)	Taxes																					
(24)	Property	234,411					234,411															
(25)	Deferred Income Tax and ITC	45,035				(151,347)	(106,312)					(707)	(579)	(64)	602					(301)		
(26)	Federal and State Income Tax	(293,642)	(10)	(3)	1,226	145,272	(147,157)	9,431		(1,899)	136	139	19	12	(110)	(1,917)		(1,524)	84	166	55	(3,021)
(27)	Payroll and Other	28,175		4-1			28,175	(40)														
(28) (29)	Total Taxes	13,979	(10)	(3)	1,226	(6,075)	9,117	9,392		(1,899)	136	(568)	(560)	(52)	492	(1,917)		(1,524)	84	(136)	55	(3,021)
(30)	Total Expenses	3,716,156	(10)	(3)	1,226	(6,075)	3,711,295	(16,751)	(57,117)	4,709	(336)	1,957	1,509	175	(1,659)	4,753		3,778	(209)	(136)	(135)	(4,937)
(31)	·																					
(32)	Allowance for Funds Used During Construction	38,536					38,536															
(33)	Net Income	478,205	10	3	(1.226)	6,075	483.066	23,383		(4.709)	336	(1.671)	(1.505)	(144)	1.356	(4.753)		(3.778)	209	136	135	(7,490)
(35)	Net income	470,203	10		(1,220)	0,073	403,000	23,303		(4,703)	330	(1,071)	(1,303)	(144)	1,330	(4,755)		(3,776)	203	130	133	(7,430)
(36)	Calculation of Revenue Requirements																					
(37)	Rate Base	12,170,585	1,474	489	(189,576)	953,294	12,936,266					(8,740)	(2,797)	(448)	3,599					22,190		
(38)	Required Operating Income	853,158	103	34	(13,289)	66,826	906,832					(613)	(196)		252					1,556		
(39) (40)	Operating Income Income Deficiency	478,205 374,953	10 94	3 31	(1,226) (12,063)	6,075 60,751	483,066 423,766	23,383 (23,383)		(4,709) 4,709	336 (336)	(1,671) 1,058	(1,505) 1,309	(144) 113	1,356 (1,104)	(4,753) 4,753		(3,778) 3,778	209 (209)	136 1,420	135 (135)	(7,490) 7,490
(41)	Revenue Deficiency	526,191	132		(16,929)	85,255		(32,814)		6,608	(472)		1,836	159	(1,549)			5,302				10,511
(42)	netchae Beneichey	320,232	101		(10,323)	03,233	334,033	(52,624)		0,000	(472)	2,403	2,030	133	(2)545)	0,071		5,502	(254)	1,555	(150)	10,511
(43)	Calculation of Income Taxes																					
(44)	Operating Revenue	4,155,825					4,155,825	6,632	(57,117)			286	5	31	(303)							(12,427)
(45)	-Operating Expense	2,722,558					2,722,558	(26,142)	(57,117)	6,608					(2,151)	6,671			(294)		(190)	(1,915)
(46) (47)	-Amortization -Taxes Other then Income	39,219 307,621				(151.347)	39,219 156,274	(40)				(707)	(579)	(64)	602			5,302		(301)		
(47)	Operating Income Before Adjs	1,086,427				151,347)	1,237,774	32,814		(6,608)		993	584	95	1,246	(6,671)		(5,302)	294	301	190	(10,511)
(49)	Additions to Income	219,800				(151,347)	68,453	32,014		(0,000)		(707)	(579)		(1,549)			(3,302)	254	(301)		(10,311)
(50)	Deductions from Income	1,373,957				47,510	1,421,467				(472)									(1,075)		
(51)	Debt Synchonization	273,838	33	11	(4,265)		291,066					(197)	(63)		81					499		
(52)	State Taxable Income	(341,569)	(33)			(68,959)	(406,306)	32,814		(6,608)	472	482	68	41	(384)			(5,302)		576	190	(10,511)
(53) (54)	State Income Tax Before Credits State Tax Credits	(33,474)	(3)	(1)	418	(6,758) (2,105)		3,216		(648)	46	47	7	4	(38)	(654)		(520)	29	56	19	(1,030)
(54)	State Tax Credits Federal Tax Deductions	(946)				(2,105)	(3,051)															
(56)	Federal Taxable Income	(307,149)	(30)	(10)	3,847	(60,096)	(363,437)	29,598		(5,960)	426	435	61	37	(346)	(6,017)		(4,782)	265	519	171	(9,481)
(57)	Federal Income Tax Before Credits	(64,501)	(6)	(2)	808	(12,620)		6,216		(1,252)	89	91	13	8	(73)	(1,264)		(1,004)	56	109	36	(1,991)
(58)	Federal Tax Credits	(194,721)				166,755	(27,966)															
(59)	Total Income Taxes	(293,642)	(10)	(3)	1,226	145,272	(147,157)	9,431		(1,899)	136	139	19	12	(110)	(1,917)		(1,524)	84	166	55	(3,021)

											R	tider Removal	s	Secondary Calculations					Fuel Adjustment	
			1		I	1		1	1							1			Remove FCA	Jstment
Line No.		Aurora	Bis Rider	Credit Rate Chg	Income Tax Tracker	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Rate Case Expenses	Sherco 3 Depr Deferral	Renewable Connect	Rider: RES	Rider: TCR	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss	Total	Revenue and Fuel Expense	Total Net of Fuel
	Workpaper Reference	WP-A34	WP-A35	WP-A36	WP-A37	WP-A38	WP-A39	WP-A40	WP-A41	WP-A42	WP-A43	WP-A44	WP-A45	WP-A46	WP-A47	WP-A49	WP-A48			
(1)		(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)	(31)	(32)	(33)	(34)	(35)	(36)	(37)	(38)	(39)	(40)
(2)	Operating Revenues																			
(3)	Retail Revenue											(80,395)	(69,700)					3,191,054	(849,346)	2,341,709
(4)	Interdepartmental							4.050			(35.294)		(97.101)					386	(147.607)	386
(5) (6)	Other Operating Total Revenue							1,258 1,258			(35,294)	(80,395)	(97,101)					620,259 3,811,699	(996,953)	472,652 2,814,747
(7)	Total Revenue							1,230			(55,254)	(80,353)	(100,801)					3,011,033	(550,533)	2,014,747
(8)	Expenses																			
(9)	Operating Expenses																			
(10)	Fuel & Purchased Energy										(35,993)							1,004,738	(991,259)	13,478
(11) (12)	Power Production Transmission										5,162	(10,020)	(91,180)					636,490 272,297		636,490 272,297
(12)	Distribution												(9,492)					128,391		128,391
(14)	Customer Accounting												(18,920)					51,861		51,861
(15)	Customer Service and Information										(150)							133,705		133,705
(16)	Sales, Econ Dev, & Other																	8,862		8,862
(17)	Administrative and General										(20.004)	(40.000)	(440 500)					251,092	(004.050)	251,092
(18) (19)	Total Operating Expenses										(30,981)	(10,020)	(119,592)					2,487,435	(991,259)	1,496,176
(20)	Depreciation											(24,302)	(20,468)					899,980		899,980
(21)	Amortization		871		2,015	137	2,154	2,884	1,562	503								54,647	(5,693)	48,954
(22)																				
(23)	Taxes											(4.722)						222.670		222.670
(24) (25)	Property Deferred Income Tax and ITC							(1,179)		(205)		(1,733) (47,150)	(3,247)				8,764	232,678 (150,377)		232,678 (150,377)
(26)	Federal and State Income Tax		(253))	(586)	(40)	(230)		(449)	(20)	(1,240)		(2,540)	13	(68)	10,619				(89,624)
(27)	Payroll and Other																	28,135		28,135
(28)	Total Taxes		(253))	(586)	(40)	(230)	(926)	(449)	(226)	(1,240)	10,131	(5,787)	13	(68)	10,619	254	20,812		20,812
(29)	T. 15				4 400			4.050		270	(22.224)	(04.404)	(4.45.045)	40	(50)	40.540	254	2 462 674	(005.050)	2 455 024
(30)	Total Expenses		618		1,429	97	1,924	1,958	1,113	278	(32,221)	(24,191)	(145,846)	13	(68)	10,619	254	3,462,874	(996,953)	2,465,921
(32)	Allowance for Funds Used During Construction																	38,536		38,536
(33)																				
(34)	Net Income		(618)		(1,429)	(97)	(1,924)	(700)	(1,113)	(278)	(3,074)	(56,205)	(20,955)	(13)	68	(10,619)) (254)	387,362	0	387,362
(35)	Coloriation of December December 1																			
(36) (37)	Calculation of Revenue Requirements Rate Base		436		1,007	68	35.541	16,766		3,127		(760,642)	(283,589)	(1,982)	10,498		(53 145)	11,918,156		11,918,156
(38)	Required Operating Income		31		71	5	2,491	1,175		219		(53,321)	(19,880)	(139)	736	34,563		870,025		870,025
(39)	Operating Income		(618))	(1,429)	(97)		(700)	(1,113)	(278)	(3,074)	(56,205)	(20,955)	(13)	68	(10,619) (254)	387,362		387,362
(40)	Income Deficiency		649		1,500	102	4,416	1,876	1,113	497	3,074	2,884	1,075	(126)	668	45,182		482,664		482,664
(41)	Revenue Deficiency		910		2,105	143	6,197	2,632	1,562	697	4,314	4,047	1,509	(177)	937	63,406	(4,872)	677,347		677,347
(42) (43)	Calculation of Income Taxes																			
(44)	Operating Revenue							1,258			(35,294)	(80,395)	(166,801)					3,811,699	(996,953)	2,814,747
(45)	-Operating Expense										(30,981)		(119,592)					2,487,435	(991,259)	1,496,176
(46)	-Amortization		871		2,015	137	2,154	2,884	1,562	503								54,647	(5,693)	48,954
(47)	-Taxes Other then Income							(1,179)		(205)		(48,883)	(3,247)				8,764	110,436		110,436
(48) (49)	Operating Income Before Adjs Additions to Income		(871))	(2,015)	(137)	(2,154) 2,154	(447) 1,705	(1,562)	(298) 298	(4,314)	(21,493) (56,245)	(43,963) (3,645)				(8,764) 8,764	1,159,181 18,284	0	1,159,181 18,284
(50)	Deductions from Income						2,154	1,705		298		(201,154)	(32,389)				(47,510)	1,138,866		1,138,866
(51)	Debt Synchonization		10		23	2	800	377		70		(17,114)	(6,381)	(45)	236	(36,946		231,212		231,212
(52)	State Taxable Income		(881))	(2,037)	(138)	(800)	881	(1,562)	(70)	(4,314)		(8,838)	45	(236)	36,946		(192,614)		(192,614)
(53)	State Income Tax Before Credits		(86)	1	(200)	(14)	(78)	86	(153)	(7)	(423)	13,772	(866)	4	(23)	3,621		(18,876)		(18,876)
(54)	State Tax Credits																2,105	(946)		(946)
(55) (56)	Federal Tax Deductions Federal Taxable Income		(795)		(1,838)	(125)	(721)	794	(1,409)	(63)	(3,891)	126,758	(7,971)	40	(213)	33,326	41,827	(172,792)		(172,792)
(50)	Federal Income Tax Before Credits		(167)		(386)	(26)			(296)	(13)		26,619	(1,674)	8	(45)			(36,286)		(36,286)
(58)	Federal Tax Credits											18,623					(24,173)	(33,516)		(33,516)
(59)	Total Income Taxes		(253))	(586)	(40)	(230)	253	(449)	(20)	(1,240)	59,014	(2,540)	13	(68)	10,619	(8,511)	(89,624)		(89,624)

Secondary Calculations

Secondary Calculations

Secondary Calculations

58

59

Cash Working Capital

Net Operating Loss

2022-2024 MYRP ADJUSTMENT SUMMARY (\$000s)

MN Electric Workpape Record Category Report Label Record Type 2022 Test Year 2023 Plan Year 2024 Plan Yea Unadjusted Total Unadjusted 388,807 539,547 669,413 Unadjusted Precedential Precedential Adjustments NSPM-Advertising (Trad) (3,154)(3,186)(3,218)WP-A1 Precedential Precedential Adjustments NSPM-Assn Dues (Trad) WP-A2 (36)Precedential Adjustments NSPM-Aviation (2.041)Precedential (2,455)(2,798)WP-A3 Precedential Precedential Adjustments NSPM-Chamber of Commerce Dues 156 156 156 WP-A4 Precedential Adjustments NSPM-Customer Deposits - A&G Expense (Trad) Precedential WP-A5 Precedential Precedential Adjustments NSPM-Donations (Trad) 584 1,685 1.686 WP-A6 Precedential Precedential Adjustments NSPM-Econ Dev Donations (Trad) 102 102 102 WP-A7 Precedential Precedential Adjustments NSPM-Econ Develop (Trad) (229)(229)(229)WP-A8 Precedential Adjustments (1,151)Precedential NSPM-Employee Expenses (1,219)(1,165)WP-A9 Precedential Adjustments NSPM-Foundation Admin 12 Precedential (150)(154)WP-A10 Precedential Adjustments NSPM-Incentive Pay_Remove Long Term (14,571)(15,447)(16,247)13 Precedential WP-A11 Precedential Precedential Adjustments NSPM-Investor Relations (326)(321)WP-A12 15 Precedential Precedential Adjustments NSPM-Monticello EPU Commission Order No Return (9,089)(7,835)(6,632)WP-A13 Precedential Precedential Adjustments NSPM-Nuclear Retention Removal (16)WP-A14 17 Precedential Precedential Adjustments NSPM-Pension Non-Qual Restoration Removal (675)(658)(611)WP-A15 Precedential Precedential Adjustments NSPM-Pension Non-Qual SERP Removal (213)(156)(144)WP-A16 Precedential Precedential Adjustments NSPM-Remove NonAsset Trading Fully Allocated Costs (3,604)(3,279)(3,201)19 WP-A17 Sub-Total Precedential (34,401)(33,030)(32,814)20 Precedential 21 CIP Approved Program Levels NSPM-CIP Approved Program Levels 22 Adjustment WP-A18 Adjustment Credit Card AutoPay NSPM-Credit Card Auto Pay Fees 6,608 23 WP-A19 Decommissioning NSPM-MN Decommissioning (472)(472)24 Adjustment (472)WP-A20 Depreciation Study: Remaining Life NSPM-Remaining Life 2.758 1.767 1 438 Adjustment 25 W/P-A21 NSPM-MN Depreciation Study TD&G Adjustment Depreciation Study: TD&G 1,145 1,548 1,821 WP-A22 Adjustment Elec Battery Reserve NSPM-MN Electric Battery Reserve Allocation 217 182 156 WP-A23 Adjustment EOL Nuclear Fuel NSPM-EOL Nuclear Fuel Update (1,543)(1,530)WP-A24 Incentive Compensation Adjustment NSPM-Incentive Pay (1.751)(1.804)(1.860)W/P-A25 Incentive Compensation NSPM-Incentive Pay_Environmental LTI 2,210 2,218 2,329 Adjustment WP-A26 NSPM-Incentive Pay_Time Based LTI Adjustment Incentive Compensation 5,668 5,960 6,202 WP-A27 Adjustment Nobles Amounts over CON NSPM-Nobles Disallowed Assets (159)WP-A28 5,302 5,302 Pension: Deferred Amort NSPM-Pension Deferred Amortization 5,302 33 Adjustment WP-A29 Pension: Discount Rate NSPM-Pension Discount Rate Int (293)(293)34 Adjustment (294)WP-A30 Pension: Extend Deferral NSPM-MN Electric Pension Extend Deferral 2,160 2,151 2,111 Adjustment WP-A31 Adjustment Pension: Retiree Medical NSPM-Pension Retiree Medical (240)(211)(190)WP-A32 37 Adjustment Transmission ROE NSPM-Transmission ROE Change 10,525 10,511 10,511 WP-A33 38 Adjustment Sub-Total Adjustment 25,514 25,317 32,133 Aurora NSPM-Aurora Deferral 2,857 2,689 Amortization WP-A34 Bis Rider NSPM-BIS Rider Recovery 1,078 995 912 Amortization WP-A35 Credit Rate Change NSPM-State Credit Rate Change (247) (263)42 Amortization WP-A36 Income Tax Tracker 2.492 2,300 Amortization NSPM-Income Tax Tracker 2.110 WP-A37 Amortization LED Street Lighting NSPM-Settlement LED Street Lighting 169 156 143 WP-A38 NOL ADIT ARAM 6,797 NSPM-NOL Tax Reform ADIT ARAM 6,582 Amortization 6,386 WP-A39 PI EPU Recovery NSPM-PI EPU Deferral 2 790 2 751 2 721 Amortization W/P_A40 Rate Case Expenses NSPM-Amortization Rate Case Expense 1,562 1,562 1,562 WP-A41 Amortization Sherco 3 Depr Deferral NSPM-Sherco 3 Deferral 771 741 714 WP-A42 Amortization Amortization **Sub-Total Amortization** 18,252 17,528 14,549 51 Rider Removals Renewable Connect NSPM-Remove Renewable Connect 4,115 4,225 4,314 WP-A43 Rider: RES 52 Rider Removals NSPM-RES Rider Removal 0 WP-A44 (0)53 Rider Removals Rider: TCR NSPM-TCR-MN Rider Removal 0 (0) WP-A45 Sub-Total Rider Removals 4,115 4,225 54 Rider Removals 4,314 56 Secondary Calculations ADIT Prorate for IRS NSPM-ADIT Prorate for IRS 322 141 (48)WP-A46

NSPM-Cash Working Capital

Sub-Total Secondary Calculations

NSPM-NOL/Credits/199

Total Revenue Deficiency

(14,434)

7,797

(6,316)

395,972

(15,448)

7.843

(7,464)

546,123

(16,944)

(10,247)

677,347

6,746

WP-A47

WP-A48

PRECEDENTIAL ADJUSTMENT DETAIL SCHEDULE

2022 Test Year

	Test Year																		
(\$000	rs)	Precedential Adjustments																	
Line No.		NSPM- Advertising (Trad)	NSPM-Assn Dues (Trad)	NSPM- Aviation	NSPM- Chamber of Commerce Dues	NSPM- Customer Deposits - A&G Expense (Trad)	NSPM- Donations (Trad)	NSPM-Econ Dev Donations (Trad)	NSPM-Econ Develop (Trad)	NSPM- Employee Expenses	NSPM- Foundation Admin	NSPM- Incentive Pay_Remove Long Term	NSPM- Investor Relations	NSPM- Monticello EPU Commission Order No Return	NSPM-Nuclear Retention Removal	NSPM-Pension Non-Qual Restoration Removal	NSPM-Pension Non-Qual SERP Remova	NSPM-Remove NonAsset Trading Fully Allocated Costs	Total
(1)	Workpaper Reference	WP-A1 (1)	WP-A2 (2)	WP-A3 (3)	WP-A4 (4)	WP-A5 (5)	WP-A6 (6)	WP-A7 (7)	WP-A8 (8)	WP-A9 (9)	WP-A10 (10)	WP-A11 (11)	WP-A12 (12)	WP-A13 (13)	WP-A14 (14)	WP-A15 (15)	WP-A16 (16)	WP-A17 (17)	(18)
(2) (3) (4) (5) (6)	Operating Revenues Retail Revenue Other Operating Total Revenue													9,089 9,089					9,089 9,089
	Customer Accounting											(3,592)			(16)				(3,608)
(13)	Sales, Econ Dev, & Other	(3,154)	(36)	(2,015)	156	7	584	102	(229)	(1,151)	(145)	(10,980)	(315)			(675)) (213) (3,604)	102 (21,768)
(15) (16)	Total Operating Expenses	(3,154)	(36)	(2,015)	156	7	584	102	(229)	(1,151)	(145)	(14,571)	(315)		(16)	(675)	(213)	(3,604)	(25,274)
(17) (18) (19) (20)	Depreciation Amortization Taxes																		
(21) (22) (23)	Property Deferred Income Tax and ITC Federal and State Income Tax	907	10	587	(45)	(2)	(168)	(29)	66	331	43	4,188	92	2,612	5	194	61	1,036	9,887
(24)				(26)	(13)	(2)	(100)	(27)			(5)		(6)					1,000	(37)
(25) (26)	Total Taxes	907	10	561	(45)	(2)	(168)	(29)	66	331	38	4,188	86	2,612	5	194	61	1,036	9,850
(27) (28)	Total Expenses	(2,248)	(25)	(1,455)	111	5	417	73	(163)	(820)	(107)	(10,383)	(229)	2,612	(12)	(481)	(152)	(2,568)	(15,424)
(29)	Allowance for Funds Used During Constru																		
(31)	Net Income	2,248	25	1,455	(111)	(5)	(417)	(73)	163	820	107	10,383	229	6,477	12	481	152	2,568	24,513
(32) (33) (34) (35)		2,248	25	1,455	(111)	(5)	(417)	(73)	163	820	107	10,383	229	6,477	12	481	152	2,568	24,513
(36)	Income Deficiency	(2,248)	(25)	(1,455)	111	5	417	73	(163)	(820)	(107)				(12)				(24,513)
(38)	Revenue Deficiency	(3,154)	(36)	(2,041)	156	7	584	102	(229)	(1,151)	(150)	(14,571)	(321)	(9,089)	(16)	(675)	(213)	(3,604)	(34,401)
(40) (41) (42)	Operating Revenue -Operating Expense	(3,154)	(36)	(2,015)	156	7	584	102	(229)	(1,151)	(145)	(14,571)	(315)	9,089	(16)	(675)) (213)) (3,604)	9,089 (25,274)
(43) (44) (45) (46)	-Amortization -Taxes Other then Income Operating Income Before Adjs Additions to Income	3,154	36	(26) 2,041	(156)	(7)	(584)	(102)	229	1,151	(5) 150		(6) 321	9,089	16	675	213	3,604	(37) 34,401
(47) (48) (49) (50)	Deductions from Income Debt Synchonization State Taxable Income State Income Tax Before Credits	3,154 309	36 3	2,041 200	(156) (15)	(7) (1)				1,151 113	150 15		321 31	9,089 891	16 2				34,401 3,371
(51) (52) (53)	Federal Tax Deductions Federal Taxable Income	2,845	32	1,841	(141)					1,038	135								31,029
(54) (55) (56)	Federal Income Tax Before Credits Federal Tax Credits Total Income Taxes	598 907	7	387 587	(30)					331	28								6,516 9,887

Northern States Power Company

PRECEDENTIAL ADJUSTMENT DETAIL SCHEDULE

2023 PLAN YEAR

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		Precedential Adjustments NSPM- NSPM- NSPM-														i			
Line No.		NSPM- Advertising (Trad)	NSPM-Assn Dues (Trad)	NSPM- Aviation	NSPM- Chamber of Commerce Dues	Customer Deposits - A&G Expense (Trad)	NSPM- Donations (Trad)	NSPM-Econ Dev Donations (Trad)	NSPM-Econ Develop (Trad)	NSPM- Employee Expenses	NSPM- Foundation Admin	NSPM- Incentive Pay_Remove Long Term	NSPM- Investor Relations	Monticello EPU Commission Order No Return	NSPM-Nuclea Retention Removal	NSPM-Pension Non-Qual Restoration Removal	NSPM-Pension Non-Qual SERP Removal	NSPM-Remove NonAsset Trading Fully Allocated Costs	Total
	Workpaper Reference	WP-A1	WP-A2	WP-A3	WP-A4	WP-A5	WP-A6	WP-A7	WP-A8	WP-A9	WP-A10	WP-A11	WP-A12	WP-A13	WP-A14	WP-A15	WP-A16	WP-A17	
(1)		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
(1) (2)	Operating Revenues																		
(3)	Retail Revenue																		
(4)	Other Operating													7,835					7,835
(5)	Total Revenue													7,835					7,835
(6) (7)	Expenses																		
(8)	Operating Expenses																		
(9)	Power Production											(3,638)							(3,638)
(10)	Transmission																		
(11)	Customer Accounting																		
(12)	Customer Service and Information Sales, Econ Dev, & Other							102											102
(14)	Administrative and General	(3,186)	(37)	(2,428)	156	7	1,685	102	(229)	(1,219)	(147)	(11,810)	(319)			(658)) (156)	(3,279)	(21,620)
(15)	Total Operating Expenses	(3,186)	(37)	(2,428)	156	7	1,685	102	(229)	(1,219)	(147)	(15,447)	(319)			(658)	(156)	(3,279)	(25,156)
(16)																			
(17)	Depreciation																		
(18)	Amortization																		
(19) (20)	Taxes																		
(21)	Property																		
(22)	Deferred Income Tax and ITC																		
(23)	Federal and State Income Tax	916	11	706	(45)	(2)	(484)	(29)	66	350	44	4,440	94	2,252		189	45	942	9,493
(24)	Payroll and Other			(27)							(5)		(7)						(38)
(25)	Total Taxes	916	11	679	(45)	(2)	(484)	(29)	66	350	39	4,440	87	2,252		189	45	942	9,455
(26)	Total Expenses	(2,270)	(26)	(1,749)	111	5	1,201	73	(163)	(868)	(108)	(11,007)	(232)	2,252		(469)) (112)	(2,337)	(15,701)
(28)	Total Expenses	(2,270)	(20)	(1,/42)	111	,	1,201	7.5	(103)	(000)	(100)	(11,007)	(232)	2,232		(402)	(112)	(2,337)	(13,701)
(29)	Allowance for Funds Used During Constru																		
(30)																			
	Net Income	2,270	26	1,749	(111)	(5)	(1,201)	(73)	163	868	108	11,007	232	5,583		469	112	2,337	23,536
(32)	Calculation of Revenue Requirements																		
(33)	Rate Base																		
(35)	Required Operating Income																		
(36)	Operating Income	2,270	26	1,749	(111)				163	868	108		232	5,583		469		2,337	23,536
(37)	Income Deficiency	(2,270)	(26)	(1,749)	111	5	1,201	73	(163)	(868)	(-00)	(,000)	(232)	(5,583)		(469)	, ()	(2,337)	(23,536)
(38)	Revenue Deficiency	(3,186)	(37)	(2,455)	156	7	1,685	102	(229)	(1,219)	(152)	(15,447)	(326)	(7,835)		(658)	(156)	(3,279)	(33,030)
(39)	Calculation of Income Taxes																		
(41)	Operating Revenue													7,835					7,835
(42)	-Operating Expense	(3,186)	(37)	(2,428)	156	7	1,685	102	(229)	(1,219)	(147)	(15,447)	(319)			(658)	(156)	(3,279)	(25,156)
(43)	-Amortization																		
(44)	-Taxes Other then Income			(27)							(5))	(7)						(38)
(45)	Operating Income Before Adjs	3,186	37	2,455	(156)	(7)	(1,685)	(102)	229	1,219	152	15,447	326	7,835		658	156	3,279	33,030
(46) (47)	Additions to Income Deductions from Income																		
(48)	Debt Synchonization																		
(49)	State Taxable Income	3,186	37	2,455	(156)	(7)	(1,685)	(102)	229	1,219	152	15,447	326	7,835		658	156	3,279	33,030
(50)	State Income Tax Before Credits	312	4	241	(15)					119	15		32	768		65		321	3,237
(51)	State Tax Credits																		
(52)	Federal Tax Deductions	0.05	2.	224	4.0	/	4.55	(n =	20.	4.00-		40.000	~ .	F 6 / F		F		2050	60 F0 -
(53)	Federal Taxable Income Federal Income Tax Before Credits	2,874 603	34 7	2,214 465	(141)				206 43	1,099 231	137 29	13,933 2,926	294 62	7,067 1,484		594 125		2,958 621	29,793 6,256
(54) (55)	Federal Tax Credits	003	/	405	(30)	(1)	(319)	(19)	43	231	29	2,920	02	1,484		125	30	021	0,236
(56)	Total Income Taxes	916	11	706	(45)	(2)	(484)	(29)	66	350	44	4,440	94	2,252		189	45	942	9,493

Northern States Power Company

PRECEDENTIAL ADJUSTMENT DETAIL SCHEDULE 2024 PLAN YEAR

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			1		1	NSPM-	I	l	Pi	recedential A	ajustments	1 1		NSPM-	I	I	1	1	
Line No.		NSPM- Advertising (Trad)	NSPM-Assn Dues (Trad)	NSPM- Aviation	NSPM- Chamber of Commerce Dues	Customer Deposits - A&G Expense (Trad)	NSPM- Donations (Trad)	NSPM-Econ Dev Donations (Trad)	NSPM-Econ Develop (Trad)	NSPM- Employee Expenses	NSPM- Foundation Admin	NSPM- Incentive Pay_Remove Long Term	NSPM- Investor Relations	Monticello EPU Commission Order No Return	NSPM-Nuclea Retention Removal	NSPM-Pension Non-Qual Restoration Removal	NSPM-Pension Non-Qual SERP Removal	NSPM-Remove NonAsset Trading Fully Allocated Costs	Total
	Workpaper Reference	WP-A1	WP-A2	WP-A3	WP-A4	WP-A5	WP-A6	WP-A7	WP-A8	WP-A9	WP-A10	WP-A11	WP-A12	WP-A13	WP-A14	WP-A15	WP-A16	WP-A17	·
(1)		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
(2)	Operating Revenues																		
(3)	Retail Revenue																		
(4)	Other Operating Total Revenue													6,632					6,632 6,632
(5) (6)	Total Revenue													0,032					0,032
	Expenses																		
(8)	Operating Expenses											(0.774)							(0.774)
(9) (10)	Power Production Transmission											(3,771)							(3,771)
(11)	Customer Accounting																		
(12)	Customer Service and Information																		
(13)	Sales, Econ Dev, & Other	(2.240)	(27)	(0.770)	454	_		102	(220)	(4.4.55)	(4.40)	40.50	(222)					(2.204)	102
(14) (15)	Administrative and General Total Operating Expenses	(3,218)	(37)	(2,770)	156 156	7	1,686 1,686	102	(229)	(1,165)	(149)		(323)			(611)	/ /	V / /	(22,473) (26,142)
(16)	Total Operating Expenses	(3,210)	(51)	(2,110)	130	,	1,000	102	(227)	(1,103)	(140)	(10,247)	(323)			(011) (144)	(3,201)	(20,142)
(17)	Depreciation																		
(18)	Amortization																		
(19) (20)	Taxes																		
(21)	Property																		
(22)	Deferred Income Tax and ITC																		
(23)	Federal and State Income Tax	925	11	804	(45)	(2)	(485)	(29)	66	335	44		95	1,906		176	41	920	9,431
(24)	Payroll and Other Total Taxes	925	11	(28) 777	(45)	(2)	(485)	(29)	66	335	(5)		(7) 88	1,906		176	41	920	9,392
(26)	Total Taxes	723	- 11	,,,,	(43)	(2)	(405)	(27)	00	333	37	4,070	00	1,700		170	71	720	7,572
(27)	Total Expenses	(2,293)	(26)	(1,994)	111	5	1,201	73	(163)	(830)	(110)	(11,577)	(235)	1,906		(435)	(103)	(2,281)	(16,751)
(28)	Alleman for Foods Used Dusing Country																		
(29)	Allowance for Funds Used During Constru																		
	Net Income	2,293	26	1,994	(111)	(5)	(1,201)	(73)	163	830	110	11,577	235	4,726		435	103	2,281	23,383
(32)																			
(33)	Calculation of Revenue Requirements																		
(34)	Rate Base Required Operating Income																		
(36)	Operating Income	2,293	26	1,994	(111)	(5)	(1,201)	(73)	163	830	110	11,577	235	4,726		435	103	2,281	23,383
(37)	Income Deficiency	(2,293)	(26)	(1,994)	111	5	1,201	73	(163)	(830)	(110)	(,0)	(235)	(4,726)		(435	(-00)	(2,281)	(23,383)
(38)	Revenue Deficiency	(3,218)	(37)	(2,798)	156	7	1,686	102	(229)	(1,165)	(154)	(16,247)	(330)	(6,632)		(611)) (144)	(3,201)	(32,814)
(39)	Calculation of Income Taxes																		
(41)	Operating Revenue													6,632					6,632
(42)	-Operating Expense	(3,218)	(37)	(2,770)	156	7	1,686	102	(229)	(1,165)	(149)	(16,247)	(323)			(611)	(144)	(3,201)	(26,142)
(43)	-Amortization -Taxes Other then Income			(28)							(5)	\	(7)						(40)
(44)	Operating Income Before Adjs	3,218	37	2,798	(156)	(7)	(1,686)	(102)	229	1,165	154)	330	6,632		611	144	3,201	32,814
(46)	Additions to Income	5,210	57	-,,,,0	(130)	(7)	(1,000)	(102)	22)	1,100	134	*V,= 1/	550	0,032		011		J,201	52,017
(47)	Deductions from Income																		
(48)	Debt Synchonization State Taxable Income	3,218	37	2,798	(156)	(7)	(1,686)	(102)	229	1,165	154	16,247	330	6,632		611	144	3,201	22 01 4
(49) (50)	State Taxable Income State Income Tax Before Credits	3,218 315	4	2,798 274	(156)					1,165	154		330	6,632		611		3,201	32,814 3,216
(51)	State Tax Credits	515	-7	2/7	(13)	(1)	(105)	(10)		114	15	1,372	32	030		00	14	514	J,210
(52)	Federal Tax Deductions																		
(53)	Federal Taxable Income	2,902	33 7	2,524	(141)					1,051 221	139		297	5,982		551 116		2,887 606	29,598
(54) (55)	Federal Income Tax Before Credits Federal Tax Credits	610	/	530	(30)	(1)	(319)	(19)	43	221	29	3,078	62	1,256		116	2/	606	6,216
(56)	Total Income Taxes	925	11	804	(45)	(2)	(485)	(29)	66	335	44	4,670	95	1,906		176	41	920	9,431

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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.

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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

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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 2021 test year or the 2022 and 2023 plan years.

Services Provided to Wholesale Customers in 2021

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 2021 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.

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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 2021-2023.

Test Year Wholesale Transactions

During 2021, 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 2019 and 2021. In addition, Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A21 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

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Revenues in the income statement as shown in Workpapers Vol 4, Tab R5: "Other Revenues"

Table 1
Asset Based Energy Sales Transactions

State of Minnesota Jurisdiction	2020	2022 Budget
Revenues	\$173.6M	\$125.2M
COGS *	(\$125.4M)	(\$117.8M)
Margin	\$48.2M	\$7.4M

^{*}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 MISC SERVICE REV)" and totaling \$1,363,375 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 MYRP.

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 \$689,446 in

Northern States Power Company State of Minnesota Electric Jurisdiction Docket No. E002/GR-21-630 Exhibit___(BCH-1), Schedule 14 Page 6 of 6

2021. These revenues flow into Other Operating Revenue as shown in Workpapers Vol 4, Tab R5, labeled "OTHER REVENUE ."

Conclusions

After reviewing the services anticipated to be provided to wholesale customers in 2021 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.

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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 [TRADE SECRET BEGINS TRADE SECRET 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.

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NSP Wholesale Customer Summary

as of July 14, 2021

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

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

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.

Prop book Other deals

MISO interface/scheduling

Energy services agreement

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. [PROTECTED DATA BEGINS...

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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.

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- 1 NSPM's proprietary book budget after joint operating agreement for 2022-2026 is targeted at \$7.0M, \$7.6M, \$5.2M, respectively. This transaction is part of the proprietary budget target however we do not specifically identify the revenue and cost of the deals that fall within the \$7M, 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
- 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.
- 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.

This amount agrees to either the "NSP Capacity ZRC Revenue" or "NSP Service Fee Revenue" budget file without exception.
The budgeted gen book magin for 2020 - 2024 is \$87M, \$94M, \$98M, \$114M, and \$154M, respectively. The budgeted amounts are a subset of this budget and are not budgeted on a contract by contract basis. These amounts are not included in the 2020 - 2024 budget due to timing of deal execution (i.e. deal was executed after preparation of 2020-2024 budget)

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Long-Term Purchased Power Capacity Cost Forecast by Contract

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2024	Jun							
2024	Jul							
2024	Aug							
2024	Sep							
2024	Oct							
2024	Nov							
2024	Dec							
2022		_	-	-	-	-	-	158
2023		-	-	-	-	_	_	161
2024								164

^{*}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):

Specifies the rate that is paid per unit of capacity that is purchased. Fixed Operations and Maintenance rate; defined in each contract. Demand Rate FOM Rate

Capacity Factor Adjustment Lowers the capacity payment if the facility is producing below a capacity factor of 70%

Defined in contracts and is fixed for the term of the agreement.
Fixed rate as defined by contract
Fixed rate as defined by contract
Fixed rate as defined by contract
Adjustment Factor-1 as defined by contract Fuel Inventory Rate FR1 FR2 FR3

AF1 Bonus Factor - 1 as defined by contract Capacity Loss Factor as defined by contract BF1 CLF

CTUP

Capacity True-Up Payment Committed Capacity True-up Factor based on the Tested Capacity Ratio (TCR) **CCTF**

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Economic Development Analysis - Commercial Inputs

2022 Economic Development

Average Cost for Industrial/Commercial installation of 500KVA Txfs.	\$ 31,000	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	\$ 330,599	Schedule 16, Attachment B, Line 18
Other Revenue Requirements Associated with Additional ED Customer	\$ 18,205	Schedule 16, Attachment B, Lines 16, 19, 20, 21
Total Revenue Requirements	\$ 348,804	Schedule 16, Attachment B, Line 22
Potential Customer Benefit in Year 1	\$ (202,343)	Schedule 16, Attachment B, Line 24
Potential Customer Benefit in Year 2	\$ 127,354	Schedule 16, Attachment B, Line 24
Potential Cumulative Customer Benefit over Life of Investment	\$ 1,214,959	Schedule 16, Attachment B, Line 26

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;" and

"...would remove non-asset based margins and their associated embedded costs from the revenue requirement..."²

In 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

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

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.

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 2022 test year and 2023-2024 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 14.75 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 2018-2020 actuals and 2022-2024 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:

<u>System</u>	<u>Description</u>
ADMS	Advanced Distribution Management System
BookRunner	
Commodity XL	Manage commodity trading logistics and risk management
CXT	Customer Experience Transformation
SAP/SAP GL	General ledger system used to account for trade activity for financial reporting
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 2020 actual and the 2022-2024 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 2022-2024 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 2022 test year and 2023-2024 plan years revenue requirements related to non-asset based trading. Attachment C shows the 2022-2024 IT systems capital revenue requirement calculation.

Conclusion

As shown in Attachment D, using the above described assumptions and methodology, each of the 2022 test year and 2023-2024 plan years includes between \$3.2 million and \$3.6 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
Non-Asset Trading Fully Allocated O&M Costs

Fully Allocated Costs

O&M Expenses		2018		2019		2020		hree Year vg (2018- 2020)	2	022 Test Year	20	023 Plan Year	20	024 Plan Year
Trading	\$	772,826	\$	906,667	\$ 2	L,172,522	\$	950,672	\$1	,169,946	\$1	1,200,429	\$1	.,232,206
Trading - SIP	\$	854,215	\$ 1	1,867,506	\$ 2	L,649,791	\$:	1,457,171	\$	981,147	\$	893,604	\$	892,557
Risk	\$	271,989	\$	352,042	\$	398,678	\$	340,903	\$	566,266	\$	583,254	\$	600,752
Accounting	\$	68,290	\$	76,619	\$	63,766	\$	69,558	\$	14,896	\$	15,343	\$	15,803
Indirect Labor Overhead	\$	527,519	\$	536,541	\$	621,839	\$	561,966	\$	701,610	\$	720,763	\$	713,445
Total Fully Allocated O&M Exp	\$2	2,494,839	\$3	3,739,375	* \$3	3,906,596	\$3	3,380,270	\$3	3,433,865	\$3	3,413,393	\$3	3,454,763

System Costs Related to Non-Asset Trading

A.	tta	cr	۱m	er	١T

	2020 Actual	2022 TY	2023 Plan Year	2024 Plan Year
Operating Revenues				_
Retail	3,490,554,325	3,566,283,616	3,562,641,659	3,585,744,632
Interdepartmental	688,543	389,070	390,549	393,894
Other Operating Revenue - Non-Retail	954,577,441	710,717,875	735,016,926	694,293,495
Total Operating Revenues	4,445,820,309	4,277,390,561	4,298,049,133	4,280,432,021
NSPM Non-Asset Based Trading Revenue	111,151,707	82,752,139	56,322,537	40,094,880
Non-Asset Trading as Percent of Total	1.95%	1.93%	1.31%	0.94%

Actual and Fcst Depr Expense Year

Row Labels	Sum of 2020	Sum of Est 2022	Sum of Est 2023	Sum of Est 2024
ADMS	326,767	429,362	429,362	425,479
ВО	-	-	-	-
BookRunner	3	15	15	15
COMMODITY XL	113,507	112,155	112,155	112,155
CXT	1,176,602	2,327,051	2,074,844	1,918,159
Documentum	-	-	-	-
PCI MISO	-	-	-	-
SAP	1,139,360	971,000	915,355	790,839
SAP GL	2,019,635	2,018,494	2,018,494	2,018,494
WAM	7,883,035	9,684,191	9,684,191	9,684,191
Grand Total	12,658,909	15,542,268	15,234,417	14,949,332
IT Dep'n related to Non-Asset trading	246,507	300,687	199,635	140,031

Depr Reserves and Net Book Values by Year

Row Labels		Sum of 2022 Depr Reserve	Sum of 2023 Depr Reserve	Sum of 2024 Depr Reserve
ADMS		1,216,729	1,646,091	2,071,570
ВО		882,571	882,571	882,571
BookRunner		33	48	63
COMMODITY XL		415,166	527,321	639,477
CXT		13,139,742	15,214,586	17,132,744
Documentum		2,520,332	2,520,332	2,520,332
PCI MISO		1,616,480	1,616,480	1,616,480
SAP		4,278,030	5,193,386	5,984,225
SAP GL		14,243,845	16,262,339	18,280,832
WAM		46,601,869	56,286,060	65,970,251
Grand Total		84,914,796	100,149,213	115,098,545
Undepreciated Balances related to Non-	Asset trading	3,610,031	1,937,527	1,508,275

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Northern States Power Company Non-Asset Trading Fully Allocated O&M Costs

Rate Analysis	2022	2023	2024
Data Pasa			
Rate Base EOY Net Plant	4,480,412	1 744 144	985,490
	, ,	1,744,144	,
Depreciation POYAL - Pl	300,687	199,635	140,031
BOY Net Plant	4,781,099	1,943,779	1,125,520
Average Rate Base	4,630,755	1,843,961	1,055,505
Revenue Requirements			
Debt Return	104,200	41,500	23,700
Equity Return	223,700	89,100	51,000
Current Income Tax Requirement	90,200	35,900	20,600
Book Depreciation	300,687	199,635	140,031
Annual Deferred Tax	-	-	-
ITC Flow Thru	-	-	-
Tax Depreciation & Removal Expense	300,687	199,635	140,031
AFUDC Expenditure	-	-	-
Book Depreciation Cleared to Operating	-	-	-
Avoided Tax Interest	-	-	-
Property Tax	-	-	-
Total NSPM Revenue Requirements	718,787	366,135	235,331
MN Jurisdictional Demand Allocator	87.1003%	87.1003%	87.1003%
Minnesota Jurisdiction Revenue Requiremer	626,066	318,905	204,974

Attachment C

Last Authorized Cap Structure (2019 from 2016 MYRP)

			Weighted
Capital Structure	Rate	Ratio	Cost
Long Term Debt	4.7500%	45.8100%	2.1800%
Short Term Debt	4.3100%	1.6900%	0.0700%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	9.2000%	52.5000%	4.8300%
Required Rate of Return			7.0800%
Tax Rate (MN)	28.7420%		

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Northern States Power Company

Attachment D

Non-Asset Trading Fully Allocated O&M Costs

1 ton 1100ct 11uomg 1 uny 1mocuteu			
	Total	NSPM Ele	ectric
	2022TY	2023PY	2024PY
O&M from cost study			
Allocation Method			
Fully Allocated O&M Expenses	3,433,865	3,413,393	3,454,763
Associated IT costs			
Allocation Method			
IT Depreciaton costs	300,687	199,635	140,031
Revenue requirement on IT in rate base	418,100	<u>166,500</u>	95,300
Total associated IT costs	718,787	366,135	235,331
Total NSPM Costs	4,152,652	3,779,528	3,690,094
EEnergy	86.7239%	86.7239%	86.7239%
EDemandProd	87.1003%	87.1003%	87.1003%
	Minnesota	a Electric Ju	risdiction
	2022TY	2023PY	2024PY
O&M from cost study	•	-	-
Allocation Method			
Fully Allocated O&M Expenses	2,977,982	2,960,228	2,996,105
Associated IT costs			
Allocation Method			
IT Depreciaton costs	261,899	173,883	121,967
Revenue requirement on IT in rate base	364,166	145,022	83,007
Total associated IT costs	626,066	318,905	204,974
MN Electric Jurisdiction Adjustment	3,604,047	3,279,132	3,201,079

Northern States Power Company Electric Utility - State of Minnesota Production Tax Credits (PTCs) 2022-2024 MYRP (\$000's)

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(84)

(190,169)

2022 2024 MWDD	
2022-2024 MYRP	
(\$000's)	
MWH	Annual - 2022
Grand Meadow	-
Nobles	2,850
Pleasant Valley	769,300
Border Winds	635,562
Courtenay	718,790
Blazing Star I	734,955
Foxtail	586,509
Lake Benton	397,412
Blazing Star II Crowned Ridge	744,874 731,756
Jeffers	167,375
Community Wind North	102,230
Mower	339,767
North Wind Farm	1,344
Dakota Range	984,563
Freeborn	680,771
Total	7,598,057
PTC Rate/Mwh	\$ 25.00
F I C I Nate/MWII	25.00
PTCs	
Grand Meadow	-
Nobles	57
Pleasant Valley	19,233
Border Winds	15,889
Courtenay	17,970
Blazing Star I	18,374
Foxtail	14,663
Lake Benton Blazing Star II	9,935 18,622
Crowned Ridge	18,294
Jeffers	4,184
Community Wind North	2,556
Mower	8,494
North Wind Farm	27
Dakota Range	24,614
Freeborn	17,019
T-4-I	400.004
Total	\$ 189,931
State of MN Energy Allocator	86.7239%
State of MN PTCs	\$ 164,715
•	
Revenue Requirement Conversion Factor	1.40335
01.1 (141) D	(004.450)
State of MN Revenue Requirements	\$ (231,153)
Interchange Agreement Energy Allocation	17.6941%
interchange Agreement Energy Anocation	17.034170
Interchange Agreement Revenue Offset	\$ (40,900)
ů ů	
State of MN Revenue Requirements (Net of IA)	\$ (190,253)
MN RES Rider Removal	
Grand Meadow	- (44)
Nobles	(41)
North Wind Farm Rider Removal Total PTC	(19)
Riuei Removai Total PTC	(60)
Revenue Requirement Conversion Factor	1.40335
. to to the order of the order of the order of the order	1.40000

Total Rider Removal PTC (Tax Gross Up)

MN PTC Rev Req net of Rider Removal \$

Northern States Power Company Docket No. E002/GR-21-630 Exhibit___(BCH-1) Schedule 18 Electric Utility - State of Minnesota Production Tax Credits (PTCs) Page 2 of 3 2022-2024 MYRP (\$000's) **MWH** Annual - 2023 Grand Meadow 32,195 721,767 Nobles Pleasant Valley 769,300 **Border Winds** 635,562 740,785 Courtenay Blazing Star I 759,156 Foxtail 594,857 Lake Benton 397,412 Blazing Star II 760,312 746,922 Crowned Ridge **Jeffers** 170,844 Community Wind North 104,349 346,809 Mower North Wind Farm 354,064 Dakota Range 984,563 689,654 Freeborn 8,808,549 Total PTC Rate/Mwh 25.00 \$ **PTCs** Grand Meadow 483 Nobles 14,435 Pleasant Valley 19,233 Border Winds 15,889 Courtenay 18.520 Blazing Star I 18,979 Foxtail 14,871 Lake Benton 9,935 Blazing Star II 19,008 Crowned Ridge 18,673 **Jeffers** 4,271 Community Wind North 2,609 8,670 Mower North Wind Farm 7,081 Dakota Range 24,614 Freeborn 17,241 Total \$ 214,513 State of MN Energy Allocator 86.7239% State of MN PTCs \$ 186,034 Revenue Requirement Conversion Factor 1.40335 State of MN Revenue Requirements \$ (261,071) Interchange Agreement Energy Allocation 17.8557% Interchange Agreement Revenue Offset \$ (46,616)State of MN Revenue Requirements (Net of IA) \$ (214,455) MN RES Rider Removal **Grand Meadow** (20)(10,284)Nobles North Wind Farm (5,045)Rider Removal Total PTC (Tax Gross Up) (15,348) Revenue Requirement Conversion Factor 1.40335 Total Rider Removal PTC (Tax Gross Up) (21,539)

MN PTC Rev Reg net of Rider Removal \$

(192,916)

Northern States Power Company Electric Utility - State of Minnesota Production Tax Credits (PTCs) 2022-2024 MYRP (\$000's)

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(193,385)

2022-2024 MYRP (\$000'c)	
(\$000's)	
MWH Grand Meadow	Annual - 2024 305,708
Nobles	723,330
Pleasant Valley	770,093
Border Winds	637,092
Courtenay	742,093
Blazing Star I	760,188
Foxtail	595,729
Lake Benton	397,783
Blazing Star II	761,236
Crowned Ridge Jeffers	747,914 171,302
Community Wind North	104,465
Mower	347,158
North Wind Farm	354,446
Dakota Range	1,005,904
Freeborn	696,388
Total	9,120,829
PTC Rate/Mwh \$	25.00
PTCs	
Grand Meadow	4,586
Nobles Pleasant Valley	14,467
Border Winds	19,252 15,927
Courtenay	18,552
Blazing Star I	19,005
Foxtail	14,893
Lake Benton	9,945
Blazing Star II	19,031
Crowned Ridge	18,698
Jeffers	4,283
Community Wind North Mower	2,612
North Wind Farm	8,679 7,089
Dakota Range	25,148
Freeborn	17,410
Total \$	219,578
State of MN Energy Allocator	86.7239%
State of MN PTCs \$	190,426
Revenue Requirement Conversion Factor	1.40335
State of MN Revenue Requirements \$	(267,235)
Interchange Agreement Energy Allocation	17.8555%
Interchange Agreement Revenue Offset \$	(47,716)
State of MN Revenue Requirements (Net of IA) \$	(219,519)
MN RES Rider Removal	
Grand Meadow	(3,267)
Grand Meadow Nobles	(10,306)
Grand Meadow Nobles North Wind Farm	(10,306) (5,050)
Grand Meadow Nobles	(10,306)
Grand Meadow Nobles North Wind Farm	(10,306) (5,050)

MN PTC Rev Req net of Rider Removal \$

NSPM Minnesota Retail - Electric

Annual Revenue Requirement Impact

IRS Pro-Rate Method Accumulated Deferred Tax Adjustment

Including NOL Annual Deferred at Last Authorized Rate of Return Test Year Ending December 31, 2022

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2022	
2022	

321,528

Annual Defer	red Tax Expe	nse	92,347,882		0		92,347,882	2
	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%	7,695,657	7,063,137	-	-	7,695,657	7,063,137
February	307	84.11%	7,695,657	6,472,785	-	-	7,695,657	6,472,785
March	276	75.62%	7,695,657	5,819,182	-	-	7,695,657	5,819,182
April	246	67.40%	7,695,657	5,186,662	-	-	7,695,657	5,186,662
May	215	58.90%	7,695,657	4,533,058	-	-	7,695,657	4,533,058
June	185	50.68%	7,695,657	3,900,538	-	-	7,695,657	3,900,538
July	154	42.19%	7,695,657	3,246,935	-	-	7,695,657	3,246,935
August	123	33.70%	7,695,657	2,593,331	-	-	7,695,657	2,593,331
September	93	25.48%	7,695,657	1,960,811	-	-	7,695,657	1,960,811
October	62	16.99%	7,695,657	1,307,207	-	-	7,695,657	1,307,207
November	32	8.77%	7,695,657	674,688	-	-	7,695,657	674,688
December	1	0.27%	7,695,657	21,084	-	-	7,695,657	21,084
							Total	42,779,418
								(Increase)/ decrease to accumulated deferred taxes
					Increase/(Decr	ease) in Rate Base		(42,779,418)
					BOY/EOY	Average		(46,173,941)
					Accumulated	d Deferred Taxes Ad	justment	3,394,523
Capital Struc	ture - Last A	uthorized			Capital Structur	e - Proposed		
Composite Ta	x Rate			28.74%	Composite Tax F	Late		28.74%
Weighted Cos				0.07%	Weighted Cost of			0.01%
Weighted Cos				2.18%	Weighted Cost of			1.94%
Weighted Cos				2.25%	Weighted Cost of			1.95%
Weighted Cos	t of Equity			4.76%	Weighted Cost of	f Equity		5.36%
Required Ra	te of Return			7.01%	Required Rate of	of Return		7.31%
Equity Return	Tax RR			1.92%	Equity Return T	ax RR		2.16%
RB Revenue I		actor		8.9239%	RB Revenue Req	uirement Factor		9.4720%
Increase/(D	ecrease) in R	evenue Requ	uirement		Increase/(Decr	ease) in Revenue R	equirement	
		-			1 1 70	ъ . т		

302,922

Annual Revenue Requirement Impact

NSPM Minnesota Retail - Electric

Annual Revenue Requirement Impact

IRS Pro-Rate Method Accumulated Deferred Tax Adjustment

Including NOL Annual Deferred at Last Authorized Rate of Return Plan Year Ending December 31, 2023

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2023	

141,444

Annual Defer	red Tax Exper	ıse	40,754,115		0		40,754,115	j
	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%	3,396,176	3,117,038	_	_	3,396,176	3,117,038
February	307	84.11%	3,396,176	2,856,510	_	_	3,396,176	2,856,510
March	276	75.62%	3,396,176	2,568,068	_	_	3,396,176	2,568,068
April	246	67.40%	3,396,176	2,288,930	_	_	3,396,176	2,288,930
May	215	58.90%	3,396,176	2,000,487	_	_	3,396,176	2,000,487
June	185	50.68%	3,396,176	1,721,350	-	_	3,396,176	1,721,350
July	154	42.19%	3,396,176	1,432,907	-	-	3,396,176	1,432,907
August	123	33.70%	3,396,176	1,144,465	-	-	3,396,176	1,144,465
September	93	25.48%	3,396,176	865,327	-	-	3,396,176	865,327
October	62	16.99%	3,396,176	576,885	-	-	3,396,176	576,885
November	32	8.77%	3,396,176	297,747	-	-	3,396,176	297,747
December	1	0.27%	3,396,176	9,305	-	-	3,396,176	9,305
							Total	18,879,018
								(Increase)/ decrease to accumulated deferred taxes
					Increase/(Decr	ease) in Rate Base		
					Pro-Rate Me	ethod		(18,879,018)
					BOY/EOY	Average		(20,377,058)
					Accumulated	d Deferred Taxes Ad	justment	1,498,039
Capital Struc	ture - Last A	uthorized			Capital Structur	e - Proposed		
Composite Ta				28.74%	Composite Tax F	-		28.74%
Weighted Cos				0.07%	Weighted Cost of			0.01%
Weighted Cos				2.18%	Weighted Cost of			1.91%
Weighted Cos				2.25%	Weighted Cost of			1.92%
Weighted Cos				4.76%	Weighted Cost of			5.36%
Required Ra	1 ,			7.01%	Required Rate			7.28%
Equity Return				1.92%	Equity Return T			2.16%
	Requirement F	actor		8.9239%	RB Revenue Req			9.4420%
	ecrease) in R		irement			ease) in Revenue R	equirement	
				100 (00	. 15	ъ т	-	

133,683

Annual Revenue Requirement Impact

NSPM Minnesota Retail - Electric

Increase/(Decrease) in Revenue Requirement

Annual Revenue Requirement Impact

IRS Pro-Rate Method Accumulated Deferred Tax Adjustment

Including NOL Annual Deferred at Last Authorized Rate of Return Plan Year Ending December 31, 2024

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2024

(48,119)

								102T
Annual Defer	ed Tax Exper	ise	(13,835,171)		0		(13,835,171)	
Allinual Delen	ed Tax Exper	ise	MN Jurisdiction	MN Jurisdiction			(13,833,171)	
	Days to	Prorate	Prorated Plant	Prorated Plant	MN Jurisdiction	MN Jurisdiction	Monthly	Prorated Monthly
	Prorate	Factor	Deferred	Deferred	NOL	Prorated NOL	Expense	Expense
January	335	91.78%	(1,152,931)	(1,058,169)	-	-	(1,152,931)	(1,058,169)
February	307	84.11%	(1,152,931)	(969,725)	-	-	(1,152,931)	(969,725)
March	276	75.62%	(1,152,931)	(871,805)	-	-	(1,152,931)	(871,805)
April	246	67.40%	(1,152,931)	(777,044)	-	-	(1,152,931)	(777,044)
May	215	58.90%	(1,152,931)	(679,124)	-	-	(1,152,931)	(679,124)
June	185	50.68%	(1,152,931)	(584,362)	-	-	(1,152,931)	(584,362)
July	154	42.19%	(1,152,931)	(486,442)	-	-	(1,152,931)	(486,442)
August	123	33.70%	(1,152,931)	(388,522)	-	-	(1,152,931)	(388,522)
September	93	25.48%	(1,152,931)	(293,760)	-	-	(1,152,931)	(293,760)
October	62	16.99%	(1,152,931)	(195,840)	-	-	(1,152,931)	(195,840)
November	32	8.77%	(1,152,931)	(101,079)	-	-	(1,152,931)	(101,079)
December	1	0.27%	(1,152,931)	(3,159)	-	-	(1,152,931)	(3,159)
							Total	(6,409,032)
								(Increase)/ decrease to accumulated deferred taxes
					Increase/(Decre	ease) in Rate Base		
					Pro-Rate Me	,		6,409,032
					BOY/EOY			6,917,585
					·	d Deferred Taxes Ad	iustment	(508,553)
							, •••	(200,200)
Capital Struc	ture - I act A	uthorized			Capital Structur	e - Proposed		
Composite Ta		anionzeu		28.74%	Composite Tax R	-		28.74%
Weighted Cos				0.07%	Weighted Cost of			0.01%
O				2.18%	U			1.93%
~	ghted Cost of LTD 2.18% Weighted Cost of LTD ghted Cost of Debt 2.25% Weighted Cost of Debt				1.94%			
Weighted Cos					5.36%			
				7.01%	Required Rate of			7.30%
	Required Rate of Return7.01%Required Rate of ReturnEquity Return Tax RR1.92%Equity Return Tax RR				2.16%			
RB Revenue R		actor		8.9239%	RB Revenue Req			9.4620%
111) Ite venue i	equirement i			0.723770	in hevenue neq	and new r		7.102070

(45,383)

Increase/(Decrease) in Revenue Requirement

Annual Revenue Requirement Impact

NSPM Minnesota Retail - Electric IRS Pro-Rate Method Accumulated Deferred Tax Adjustment

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Including NOL Annual Deferred at Last Authorized Rate of Return Test Year Ending December 31, 2022

Prorate Adjustment Factor

		Prorated	Prorate
Days	Month	Days	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
3	365		

Removing Double Average from Prorate Factor

Average Prorate Factor	0.463242
BOY/EOY Average Factor	0.500000
Prorate Adjustment Factor	0.036758

Northern States Power Company Electric Utility - State of Minnesota Net Operating Loss (NOL) Test Year Ending December 31, 2022 (\$000's) Docket No. E002/GR-21-630 Exhibit___(BCH-1) Schedule 20 2022-2024 MYRP Page 1 of 1

Impact of Unused/(Utilized) Tax	2020 Annual Report EOY	2021 Bridge	2021 Bridge EOY	2022 Test Year Annual Activity	2022 Test Year EOY	2023 Plan Year Annual Activity	2023 Plan Year EOY	2024 Plan Year Annual Activity	2024 Plan Year
Deductions on Rate Base	Balances	Amounts	Balances	Amounts	Balances	Amounts	Balances	Amounts	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	367,044	131,057	498,101	164,636	662,737	166,121	828,858	142,583	971,440
5. Accumulated Deferred Income Taxes (ADIT)	367,044	131,057	498,101	164,636	662,737	166,121	828,858	142,583	971,440

Impact of Unused/(Utilized) Tax Deductions on Revenue Requirements	2021 Bridge Year Utilization Adjustment	2022 Test Year Utilization Adjustment	2023 Plan Year Utilization Adjustment	2024 Plan Year Utilization Adjustment	Comment
6. Deferred Tax Asset BOY	0	0	0		Zero since compliance filing is based on current year activit
7. Deferred Tax Asset EOY	131,057	164,636	166,121		From Unused/(Utilized) columns on Line 4
8. Average Rate Base	65,529	82,318	83,060		(BOY + EOY)/2
9. Return Requirement	4,803	6,017	6,047	5,204	Rate Base * Req Rate of Return
10. RR Tax on Equity Return	1,422	1,780	1,796	1,541	(T/(1-T))*RB*Equity Return
11. Rate Base Revenue Requirement	6,225	7,797	7,843	6,746	Line 9 + Line 10
12. Deferred Tax	(131,057)	(164,636)	(166,121)	(142,583)	From Unused/(Utilized) columns on Line 5
13. Current Tax Rev Req 1	131,057	164,636	166,121	142,583	From Line 19
14. Annual Revenue Requirement Increase (Reduction)	6,225	7,797	7,843	6,746	Line 10+11+12
1 Current Income Tax Rev Req Calculation					∃
15. Utilized Deductions	-	-	-	-	Unused Annual Deductions
16. Deferred Taxes	(131,057)	(164,636)	(166,121)	(142,583)	Line 12
17. Unused State Tax Credits	- 1	-	- '	- '	From Unused/(Utilized) columns on Line 3
18. Unused Federal Tax Credits	131,057	164,636	166,121	142,583	From Unused/(Utilized) columns on Line 4
19. Current Income Tax Revenue Requirement	131,057	164,636	166,121	142,583	(T/(1-T))*(-Line 15+.79xLine16+Line17)+.79xLine 16+Lin

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MYRP Forecast Fuel Reconciliation

			2	023 Plan			
Category	202	2 Test Year		Year	202	4 Plan Year	Comments
FCA Costs							
All fuel w/o Gas Purchase Demand		1,010,257		1,011,302		1,011,157	
PPA Buyouts - Laurentian		15,683		15,683		15,683	
PPA Buyouts - FERC 557 Benson		5,926		5,888		5,848	
WI Interchange Fuel to MN		8,061		8,043		8,043	_
Fuel and Purchased Energy	\$	1,039,927	\$	1,040,915	\$	1,040,731	BCH-1, Sch. 11a-11c, column 6, row 10
Costs Not Recoverable in Fuel Clause:							
Less Fuel Handling O&M Expenses		(13,928)		(13,595)		(13,478)	
Less Renewable*Connect Costs		(35,993)		(35,993)		(35,993)	
Subtotal	\$	(49,921)	\$	(49,588)	\$	(49,471)	•
Fuel and Purchased Energy Costs in Fuel Clause	\$	990,006	\$	991,327	\$	991,259	BCH-1, Sch. 11a-11c, column 39, row 18
Other Costs Recoverable in Fuel Clause:							
PPA Buyout Amortization - FERC 407 Benson		5,780		5,738		5,693	BCH-1, Sch. 11a-11c, column 39, row 21
Total Recoverable FCA Costs	\$	995,786	\$	997,065	\$	996,953	
Fuel Revenue							
Minnesota Fuel Costs recovered through FCA		849,346		849,346		849.346	BCH-1, Sch. 11a-11c, column 39, row 3
MN Interchange Bill to WI - Variable Fuel		141,902		143,166		143,113	
PPA Buyouts Laurantian - WI Portion in Interchange Rev		2,680		2,775		2,800	
PPA Buyouts Benson - WI Portion in Interchange Rev		1,859		1,778		1,694	
Total Fuel Revenue	\$	995,786	\$	997,065	\$		BCH-1, Sch. 11a-11c, column 39, row 6
Difference in FCA Costs and FCA Revenue	\$	0	\$	(0)	\$	(0)	•

Interim rates - No RES Projects in 2022/2023

		2022 Test Year	2023 Plan Year	2024 Plan Year
se Rates				
R Rider Projects				
CapX2020 - Brookings*	Base Rates	Х	Х	Х
CapX2020 - Fargo*	Base Rates	х	Х	х
CAPX2020 - La Crosse Local*	Base Rates	х	Х	х
CAPX2020 - La Crosse MISO*	Base Rates	Х	Х	х
CAPX2020 - La Crosse MISO - WI*	Base Rates	Х	Х	Х
Big Stone - Brookings*	Base Rates	Х	Х	х
La Crosse - Madison*	Base Rates	Х	Х	х
Huntley Wilmarth*	Base Rates	Х	Х	х
MISO RECB Sch 26 and 26A net revenues**	Rider Project	✓	✓	✓
AGIS - ADMS**	Rider Project	✓	✓	✓.
AGIS - AMI**	Rider Project	✓.	✓.	✓.
AGIS - FAN**	Rider Project	✓	✓	✓.
AGIS - LoadSeer**	Rider Project	√	✓	✓.
AGIS - TOU Pilot**	Rider Project	✓	✓	✓
terim rates - No TCR Projects in 2022/2023				
S Rider Projects				
	Day Dala		,	
Courtenay Wind Farm*	Base Rates	X	X	X
Courtenay Wind Farm* Foxtail Wind Farm*	Base Rates	х	х	х
Courtenay Wind Farm* Foxtail Wind Farm* Blazing Star I Wind Farm*	Base Rates Base Rates	x x	x x	x x
Courtenay Wind Farm* Foxtail Wind Farm* Blazing Star I Wind Farm* Lake Benton Wind Farm*	Base Rates Base Rates Base Rates	х х х	x x x	x x x
Courtenay Wind Farm* Foxtail Wind Farm* Blazing Star I Wind Farm* Lake Benton Wind Farm* Blazing Star II Wind Farm*	Base Rates Base Rates Base Rates Base Rates	x x x x	x x x x	x x x x
Courtenay Wind Farm* Foxtail Wind Farm* Blazing Star I Wind Farm* Lake Benton Wind Farm* Blazing Star II Wind Farm* Crowned Ridge Wind Farm*	Base Rates Base Rates Base Rates Base Rates Base Rates	x x x x	x x x x x	x x x x x
Courtenay Wind Farm* Foxtail Wind Farm* Blazing Star I Wind Farm* Lake Benton Wind Farm* Blazing Star II Wind Farm*	Base Rates Base Rates Base Rates Base Rates	x x x x	x x x x	x x x x
Courtenay Wind Farm* Foxtail Wind Farm* Blazing Star I Wind Farm* Lake Benton Wind Farm* Blazing Star II Wind Farm* Crowned Ridge Wind Farm*	Base Rates Base Rates Base Rates Base Rates Base Rates	x x x x	x x x x x	x x x x x
Courtenay Wind Farm* Foxtail Wind Farm* Blazing Star I Wind Farm* Lake Benton Wind Farm* Blazing Star II Wind Farm* Crowned Ridge Wind Farm* Jeffers Wind Farm*	Base Rates Base Rates Base Rates Base Rates Base Rates Base Rates	x x x x x	x x x x x	x x x x x
Courtenay Wind Farm* Foxtail Wind Farm* Blazing Star I Wind Farm* Lake Benton Wind Farm* Blazing Star II Wind Farm* Crowned Ridge Wind Farm* Jeffers Wind Farm* Community Wind North*	Base Rates	x x x x x x	x x x x x x	x x x x x x
Courtenay Wind Farm* Foxtail Wind Farm* Blazing Star I Wind Farm* Lake Benton Wind Farm* Blazing Star II Wind Farm* Crowned Ridge Wind Farm* Jeffers Wind Farm* Community Wind North* Mower Wind Farm*	Base Rates	x x x x x x	x x x x x x x	x x x x x x x
Courtenay Wind Farm* Foxtail Wind Farm* Blazing Star I Wind Farm* Lake Benton Wind Farm* Blazing Star II Wind Farm* Crowned Ridge Wind Farm* Jeffers Wind Farm* Community Wind North* Mower Wind Farm* Freeborn Wind Farm*	Base Rates	x x x x x x x	x x x x x x x	x x x x x x x x
Courtenay Wind Farm* Foxtail Wind Farm* Blazing Star I Wind Farm* Lake Benton Wind Farm* Blazing Star II Wind Farm* Crowned Ridge Wind Farm* Jeffers Wind Farm* Community Wind North* Mower Wind Farm* Freeborn Wind Farm* Dakota Range Wind Farm*	Base Rates	x x x x x x x x	x x x x x x x x	x x x x x x x x
Courtenay Wind Farm* Foxtail Wind Farm* Blazing Star I Wind Farm* Lake Benton Wind Farm* Blazing Star II Wind Farm* Crowned Ridge Wind Farm* Jeffers Wind Farm* Community Wind North* Mower Wind Farm* Freeborn Wind Farm* Dakota Range Wind Farm* Borders Wind Re-Power**	Base Rates Rates Base Rates Base Rates	x x x x x x x	x x x x x x x x	x x x x x x x x
Courtenay Wind Farm* Foxtail Wind Farm* Blazing Star I Wind Farm* Lake Benton Wind Farm* Blazing Star II Wind Farm* Crowned Ridge Wind Farm* Jeffers Wind Farm* Community Wind North* Mower Wind Farm* Freeborn Wind Farm* Dakota Range Wind Farm* Borders Wind Re-Power** Pleasant Valley Wind Re-Power**	Base Rates Rates Rates Rates Rates Rider Project	x x x x x x x x	x x x x x x x x	x x x x x x x x
Courtenay Wind Farm* Foxtail Wind Farm* Blazing Star I Wind Farm* Lake Benton Wind Farm* Blazing Star II Wind Farm* Crowned Ridge Wind Farm* Jeffers Wind Farm* Community Wind North* Mower Wind Farm* Freeborn Wind Farm* Dakota Range Wind Farm* Borders Wind Re-Power** Pleasant Valley Wind Re-Power** Grand Meadows Wind Re-Power**	Base Rates Rates Rates Rater Rider Project Rider Project	x x x x x x x x	x x x x x x x x	x x x x x x x x

^{*} Included in 2022 Test Years and 2023 to 2024 Plan Years with 2022 and 2023 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 2022 Test Year and 2023 to 2024 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



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INDEPENDENT ACCOUNTANTS' REPORT ON APPLYING AGREED-UPON PROCEDURES

To the Board of Directors of Northern States Power Company, a Minnesota corporation Minneapolis, Minnesota

We have performed the procedures enumerated in the accompanying Appendix A, which were agreed to by the management of Northern States Power Company, a Minnesota corporation (the "Company", "NSP-MN" or "NSP Minnesota Company"), in evaluating the Company's 2022 through 2024 Minnesota Electric Cost of Service and Revenue Requirement Deficiency Calculation. The Company is responsible for the 2022 through 2024 Minnesota Electric Cost of Service and Revenue Requirement Deficiency Calculation and compliance with those requirements.

The Company has agreed to and acknowledged that the procedures performed are appropriate to meet the intended purpose assisting the specified parties in understanding the engagement, as described above.

We make no representation regarding the appropriateness of the procedures performed either for the purpose for which our report has been requested or for any other purpose. Accordingly, this report may not be suitable for either the purpose of which this report has been requested or for any other purpose. The procedures performed may not address all the items of interest to a user of this report and may not meet the needs of all users of this report and, as such, users are responsible for determining whether the procedures performed are appropriate for their purposes.

The procedures and associated findings based upon those procedures are included in the accompanying Appendix A.

We were engaged by the Company to perform this agreed-upon procedures engagement and conducted our engagement in accordance with attestation standards established by the American Institute of Certified Public Accountants. We were not engaged to and did not conduct an examination or review engagement, the objective of which would be the expression of an opinion or conclusion, respectively, on the Company's 2022 through 2024 Minnesota Electric Cost of Service and Revenue Requirement Deficiency Calculation. Accordingly, we do not express such an opinion or conclusion. Had we performed additional procedures, other matters might have come to our attention that would have been reported to you.

We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements related to our agreed-upon procedures engagement.

This report is intended solely for the information and use of the management of the Company and the Minnesota Public Utilities Commission ("MPUC") and is not intended to be, and should not be, used by anyone other than these specified parties.

October 22, 2021

Deloitte: Touche LLP

APPENDIX A

AGREED-UPON PROCEDURES APPLIED TO THE COMPANY'S 2022 THROUGH 2024 MINNESOTA ELECTRIC COST OF SERVICE AND REVENUE REQUIREMENT DEFICIENCY CALCULATION

D&T obtained the Minnesota Electric Cost of Service (COS) by Adjustment Report ("MN E COS") for the 2022-2024 test years and the Minnesota Electric Position Summary Report ("Position Summary") for the 2022-2024 test years, and the Keno Board (a report summarizing the preparation and review of each input/adjustment to 2022-2024 test years COS and revenue requirement deficiency) (the "Keno Board") from management.

Base Operations and Maintenance ("O&M") Expense

D&T obtained the FERC Detail Report (a Business Objects report generated from the SAP general ledger system) and the Regulatory Information System (RIS) Validation tab (a report generated from UIPlanner software which is used to calculate revenue requirements) for the 2022-2024 test years and performed the following procedures:

- 1. We inspected that the Total Company Base O&M expense amounts from the FERC Detail Report tab (a pivot table of the FERC Detail Report) for the 2022-2024 test years agrees to the Total Company Base O&M expense amounts, which is comprised of base O&M expense amounts for MN electric, ND electric, SD electric, MN gas, and ND gas amounts, from the RIS Validation tab for the 2022-2024 test years, noting no exceptions.
- 2. We agreed the MN Electric Base O&M expense amounts on the RIS Validation tab to the MN Electric Base O&M expense amounts in the MN E COS for the 2022-2024 test years, noting no exceptions.
- 3. We inspected the Keno Board to confirm that the Base O&M expense adjustment was independently reviewed, noting no exceptions.

Base Plant

D&T obtained the JUR Verification Report ("RIS Report") (the JUR Verification Report compares a Business Objects report generated from the SAP general ledger system and a report generated from UIPlanner software by financial category) for the 2022-2024 test years and performed the following procedures:

- 1. We agreed the components of Base Plant from the Integration Data- JUR column of the RIS Report to the components of Base Plant from the Verification Query JUR column of the RIS Report, noting no exceptions.
- 2. We inspected the Keno Board to confirm that the Base Plant adjustment was independently reviewed, noting no exceptions.

Interchange Billings to NSPW

D&T obtained the Interchange Billings NSPW and NSPM report for the 2022-2024 test years and performed the following procedures:

- 1. We agreed the Total Operating Expense and Total Operating Revenue per the RIS Validation tab of the Interchange Billings NSPW and NSPM report to the Interchange group source data (G1-I/A Full Bill) at the NSPM & NSPW "Full Bill" tabs within the same report for the 2022-2024 test years, noting no exceptions.
- We agreed the NSPM MN Electric Retail- Total Operating Expense and Total Operating Revenue amounts by year on the same RIS validation tab (mentioned in step 1) to the sum of all Base Interchange activity (IA): Operating Expenses and Base IA: Operating Revenues, respectively, in the MN E COS Report for the 2022-2024 test years, noting no exceptions.
- 3. We inspected the Keno Board to confirm that the NSPM-Interchange Billings to NSPW (Rev) adjustment was independently reviewed, noting no exceptions.

Fuel Costs

D&T obtained the reconciliation of fuel costs to fuel revenues ("Fuel Reconciliation Report") for the 2022-2024 test years and performed the following procedures:

- 1. We confirmed that total fuel revenues and total fuel costs net to \$0 in the Fuel Reconciliation Report, noting no exceptions.
- 2. We inspected the Keno Board to confirm that the Fuel Costs adjustment was independently reviewed, noting no exceptions.

Base Electric Revenue

D&T obtained the Forecast Electric Retail Base Report for the 2022-2024 test years and performed the following procedures:

- 1. We agreed the NSPM MN Electric Retail operating revenue amount by year on the RIS validation tab of the Forecast Electric Retail Base Report to the Present Rev -MN tab within the same report for years 2022-2024, noting no exceptions.
- 2. We agreed the NSPM MN Electric Retail operating revenue amount by year on the RIS validation tab of the Forecast Electric Retail Base Report to the NSPM MN Electric Retail operating revenue amount in the MN E COS Report for the 2022-2024 test years, noting no exceptions.
- 3. We inspected the Keno Board to confirm that the NSPM Electric Base Revenue adjustment was independently reviewed, noting no exceptions.

Electric Fuel Revenue

D&T obtained the Budget Fuel Upload Report for the 2022-2024 test years and performed the following procedures:

- We agreed the NSPM MN Electric Retail Fuel operating revenue amount by year on the RIS validation tab of the Budget Fuel Upload Report to the Present Fuel -MN tab within the same report for the 2022-2024 test years, noting no exceptions.
- 2. We agreed the NSPM MN Electric Retail Fuel operating revenue amount by year on the RIS validation tab of the Budget Fuel Upload Report to the NSPM MN Electric Retail Fuel operating revenue amount in the MN E COS Report for the 2022-2024 test years, noting no exceptions.
- 3. We inspected the Keno Board to confirm that the NSPM Electric Fuel Revenue adjustment was independently reviewed, noting no exceptions.

Electric Rider Revenue

D&T obtained the Budget Rider Upload Report for the 2022-2024 test years and performed the following procedures:

- We agreed the NSPM MN Electric Retail Rider operating revenue amount by year on the RIS validation tab of the Budget Rider Upload Report to the Rider Template Sign-off tab within the same report for the 2022-2024 test years, noting no exceptions.
- 2. We agreed the NSPM MN Electric Retail Rider operating revenue amount by year on the RIS validation tab of the Budget Rider Upload Report to the NSPM MN Electric Retail Rider operating revenue amount in the MN E COS report for the 2022-2024 test years, noting no exceptions.
- 3. We inspected the Keno Board to confirm that the NSPM Electric Rider Revenue adjustment was independently reviewed, noting no exceptions.

Additional Input/Adjustments

D&T selected 15 samples of the remaining inputs/adjustments from the Position Summary Report, which represents 50% of the absolute value of the revenue deficiency calculation.

- For each selection, D&T agreed the selected MN Electric input/adjustment for the 2022-2024 test years to the RIS
 validation tab or equivalent supporting calculation provided by management in the respective input/adjustment file,
 noting no exceptions.
- D&T agreed each MN Electric input/adjustment selection from the RIS validation tab or the equivalent supporting
 documentation provided by management in the respective input/adjustment file to the amount in the MN E COS report
 for the 2022-2024 test years, noting no exceptions.

Allocators

D&T obtained the Budget Allocation Master List for the 2022-2024 test years and performed the following procedures:

- 1. D&T agreed the source data in the Juris Alloc tab within the Budget Allocation Master List to the RIS validation tab within the same report for the following Minnesota electric jurisdiction allocators:
 - a. ECustomerMN/SD/ND
 - b. EDemandProd
 - c. EDemandTran
 - d. EEnergy

We noted no exceptions.

2. D&T inspected the Keno Board to confirm that the Budget Allocation Master List was independently reviewed, noting no exceptions.

Capital Structure

D&T obtained the MN Capital Structures Report for the 2022-2024 test years and performed the following procedures:

- 1. D&T agreed the source data Forecasted Cost of Capital for the years 2022-2024 in the MN Capital Structures Report to the MN E COS report for the 2022-2024 test years for the following elements:
 - a. Cost of Short-Term Debt
 - b. Cost of Long-Term Debt
 - c. Cost of Common Equity
 - d. Required Rate of Return

We noted no exceptions.

2. D&T inspected the Keno Board to confirm that the MN Capital Structures Report was independently reviewed, noting no exceptions.