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 Gas Service in Minnesota

Docket No. G002/GR-21-678
Exhibit___(BCH-1)

2022 Test Year
Overall Revenue Requirements
Rate Base
Income Statement

Rate Rider Recovery 2022

November 1, 2021

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

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

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

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

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

A. In my Direct Testimony, I support the Company's Minnesota jurisdiction gas operations cost of service, revenue requirements, and revenue deficiency for the 2022 test year. Overall, the net deficiency and retail revenue requirement for the test year are summarized in Table 1 below:

Table 1

2022 Revenue Requests

Minnesota Jurisdictional ($s in millions)

Test Year	2022
Net Deficiency	$35.63
Average % increase	6.6%

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

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

My testimony also supports the 2022 requested interim rate increases discussed in the Company's Notice and Petition for Interim Rates. Company witness Mr. Gregory P. Chamberlain provides additional support for the interim rate increases, as does the Notice and Petition for Interim Rates included in Volume 1 of our Application.

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

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

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

A. I present my testimony in the following sections:

- Section II, *Case Overview*, summarizes our jurisdictional revenue requirement for the 2022 test year, and discusses the key drivers of cost increases compared to the 2010 test year established in Docket No. G002/GR-09-1153.
- Section III, *Supporting Information*, provides information related to the data provided in our application, the selection of the test year, and the jurisdictional cost of service study.
- Section IV, *Rate Base*, identifies and explains the components of rate base, and supports the reasonableness of the Company's projected 2022 test year.
- Section V, *Income Statement*, identifies and explains the major components of the income statement and supports the reasonableness of the Company's proposed 2022 test year.
- Section VI, *Utility and Jurisdictional Allocations*, explains why it is necessary for the Company to allocate costs among its affiliates and between jurisdictions, and describes the utility and jurisdictional allocators that are used in determining the test year revenue requirement.
- Section VII, *Annual Adjustments to the Test Year*, presents adjustments affecting the 2022 test year revenue requirements, providing both rate base and income statement impacts.
- Section VIII, *Costs Recovered in Riders and Tracker*, presents our proposed treatment of costs recovered in riders during the test year period,

- providing details about which riders we propose to continue to use and costs we propose to move into base rates.
- Section IX, *Compliance with Prior Commission Orders*, provides information related to specific requirements from prior Minnesota Public Utilities Commission (Commission) Orders that have not been addressed elsewhere in my testimony.
- Section X, *Conclusion*, summarizes our request.

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

A. While most of the dollar values presented in my testimony are jurisdictionalized to State of Minnesota Gas Jurisdiction, there are some instances where dollars are Total Company. Dollar values that are Total Company are labeled accordingly.

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

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

II. CASE OVERVIEW

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

A. In this section, I will:

- present the jurisdictional revenue requirement and revenue deficiencies for Minnesota for the 2022 test year;
- present a summary comparison of the costs in the test year to the costs approved in our last rate case; and
- provide an explanation of the primary sources of the changes in overall costs, including plant-related costs and operations and maintenance (O&M) costs.

A. Jurisdictional Revenue Requirements and Deficiencies

Q. PLEASE DESCRIBE THE BASIS OF THE COMPANY'S TEST YEAR PROPOSAL.

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

Q. WHAT IS THE 2022 TEST YEAR JURISDICTIONAL OVERALL REVENUE REQUIREMENT AND REVENUE DEFICIENCY?

A. The overall jurisdiction revenue requirement for the 2022 test year is $576.65 million. The 2022 test year revenue deficiency, excluding rider roll-ins, is $35.63 million. This 2022 test year revenue deficiency amount represents a 6.6 percent overall increase in retail revenues from base rates compared to projected 2022 retail revenues at present rates. A summary of the 2022 revenue deficiency (in dollars and as a percent) is provided in Exhibit___(BCH-1) Schedule 2, Summary of Revenue Requirements. The calculation of these dollar amounts is provided in Exhibit___(BCH-1) Schedule 3, Cost of Service Study Summary.

Q. WHAT IS THE AMOUNT OF THE INTERIM RATE REVENUE DEFICIENCY IN 2022?

A. The Interim Rate Petition (Petition) supports an interim revenue deficiency based on the 2022 test year of $24.9 million, which results in a proposed interim rate increase of 4.9 percent beginning January 1, 2022.

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

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

Table 2
Revenue Requirement and Revenue Deficiency

	Item	2022 Test Year Amount ($000s)	Exhibit__ (BCH-1), Sch. 3 Reference
	Average Rate Base	$934,448	Page 1, Line 43
multiplied by	Cost of capital	7.46%	Page 1, Line 20
	Operating Income Requirement	**$69,710**	Page 3, Line 145
	Current Retail Revenue	$541,016	Page 1, Line 46 + Line 47
plus	Current Other Revenue	$4,908	Page 1, Line 48
equals	Current Total Revenue	$545,924	Page 1, Line 49
minus	Operating Expenses	$423,052	Page 2, Line 61
minus	Depreciation Expense	$53,130	Page 2, Line 63
minus	Amortization Expense	$167	Page 2, Line 64
minus	Taxes	$28,946	Page 3, Line 122
plus	AFUDC	$3,693	Page 3, Line 127 + Line 128
equals	**Total Available for Return**	**$44,321**	Page 3, Line 130
	Operating Income Requirement	$69,710	Page 3, Line 145
minus	Total Available for Return	$44,321	Page 3, Line 146
equals	**Income Deficiency**	**$25,388**	Page 3, Line 147
multiplied by	Gross Revenue Conversion Factor	1.403351	Page 3, Line 149
equals	**Revenue Deficiency**	**$35,629**	Page 3, Line 150
plus	Current Retail Revenue	$541,016	Page 3, Line 153
equals	**Total Revenue Requirement**	**$576,645**	Page 3, Line 155

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

A. Yes. An explanation is provided in the Financial Information section of Volume 3 (Required Information) of this Application. In addition, work papers supporting the 2022 test year cost of service are provided in Volume 4 of this Application.

Q. HOW DOES THE COMPANY TREAT CAPITAL AND O&M COSTS IN THE 2022 TEST YEAR?

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

1. Capital, capital-related, and O&M costs follow the Company's budget, except as needed to comply with prior Commission Orders or adjustments the Company is specifically proposing in this proceeding. (Capital-related costs consist of depreciation and allowance for funds used during construction (AFUDC) as well as the cost of capital).
2. Expenses that have jurisdiction-specific regulatory accounting treatment follow that treatment. For example:
   a. Expenses related to the Company's non-qualified pension costs have regulatory adjustments based on the outcome of the Company's recent rate cases.
3. Secondary calculations necessary for a full cost of service study are based on the results of the above items.
   a. Cash Working Capital balance related to the revenues and expenses developed above
   b. Change in debt interest expense related to the budgeted change in debt costs and the budget of rate base.

B. Case Drivers

Q. HAVE YOU PREPARED A COMPARISON OF THE COSTS IN THE TEST YEAR FORECAST TO CURRENT RATES RESULTING FROM THE 2010 TEST YEAR?

A. Yes. I provide an explanation of the detailed case drivers of the deficiency using a comparison of the 2022 test year (including rider roll-ins) with the base rates in effect in 2010 as a result of Docket No. G002/GR-09-1153 (including updates for the effects of the Tax Cuts and Jobs Act (TCJA)). My analysis differs from the Direct Testimony analyses of the Company's business area witnesses, who primarily discuss costs and cost changes in terms of actual costs and budgets (not revenue deficiencies). Therefore, my discussion of key cost drivers reflects dollar values that are, in large part, different from their discussions. In addition, I discuss these drivers at a high level, and defer to the business area witnesses to provide more detail around the activities and changes giving rise to these drivers.

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

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

Table 3

Test Year Net Incremental Deficiency ($ in millions)*

	Increase (Decrease) 2022 TY to 2010 TY
Capital and Capital Related	$50.5
Amortizations	(0.1)
Taxes	15.8
Operating Expense	21.9
Other Margin Impacts	(52.4)
Total Net Incremental Deficiency	**$35.6**

**Differences between components of deficiency and total due to rounding.*

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.

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

A. Table 4 below compares the 2022 test year revenue requirements with the comparable revenue requirements for the 2010 test year, by category, for capital plant related costs as shown on Schedule 6, Detailed Case Drivers.

Table 4

Capital and Capital Related Cost Changes ($ in millions)

	Increase (Decrease) 2022 TY to 2010 TY
Distribution	$33.1
General and Intangible	9.1
Gas Production and Storage	4.9
Transmission	2.3
Other Rate Base	(1.6)
Cost of Capital	2.8
TOTAL Capital and Capital Related	$50.5

Q. PLEASE IDENTIFY THE PRINCIPAL CHANGES IN DISTRIBUTION AND GAS PRODUCTION AND STORAGE CAPITAL COSTS.

A. The test year forecast revenue requirements include a $33.1 million increase to Distribution and a $4.9 million increase to Gas Production and Storage as compared to the 2010 test year. A portion of this increase is due to the inclusion of capital investments previously recovered through the Gas Utility Infrastructure Cost (GUIC) rider (offset by rider revenues), as well as additional investment in new customer connections, mandated relocations, and the safety and reliability of our distribution and plant infrastructure. Additional information regarding distribution and gas production and storage projects are provided in the Direct Testimony of Company witnesses Ms. Joni Zich and Ms. Mary Palkovich.

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

A. The test year forecast revenue requirements include a $9.1 million increase to General & Intangible as compared to the 2010 test year. This increase is due to capital investments relating to replacing aging information technology (IT), addressing evolving cyber security threats and requirements, enhancing IT capabilities, and enhancing the customer experience. Additional information regarding general and intangible projects is discussed in the Direct Testimony of Company witness Mr. Michael O. Remington.

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

A. The test year forecast revenue requirements include a $2.8 million increase related to changes in cost of capital, compared to the overall cost of capital approved in the Company's last gas rate case. (However, the Company's interim rate request reflects the 9.04 percent return on equity (ROE) currently approved for the GUIC.) The change in cost of capital is due to a requested 10.5 percent return on equity (ROE), partially offset by a decrease in the cost of long-term debt. Company witness Mr. Paul A. Johnson describes the capital structure and costs of debt in his Direct Testimony. Company witness Mr. Dylan W. D'Ascendis of ScottMadden, Inc. discusses the ROE.

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN TAXES.

A. The test year forecast revenue requirements include an increase in current and deferred income tax of $8.3 million and property taxes of $6.6 million. The decrease in current and deferred income taxes related to the TCJA is currently being refunded to customers in base rates effective June 1, 2019, as a result of the Commission decision in Docket No. E,G999/CI-17-895, and therefore does not create an incremental change in taxes for this case. Additional information regarding property taxes is discussed in the Direct Testimony of Company witness Mr. Christopher A. Arend.

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

A. Table 5 below compares the 2022 test year forecast revenue requirements with the comparable revenue requirements for the 2010 test year, by category, for operating expenses as shown on Schedule 6, Detailed Case Drivers.

Table 5

O&M Cost Changes ($ in millions)

	Increase (Decrease) 2010 TY to 2022 TY
Gas Production and Storage	$1.4
Transmission	1.2
Distribution	15.0
Customer Accounting / Info / Service	(1.4)
A&G	5.7
TOTAL O&M	$21.9

Q. WHAT ARE THE REASONS FOR THE INCREASE IN GAS PRODUCTION AND STORAGE OPERATING EXPENSE?

A. The test year forecast revenue requirements include a $1.4 million increase in expenses related to operating expenses for our gas peaking plants and clean-up efforts at former manufactured gas plants in the Company's service territory. Additional information regarding gas production and storage operating expenses are discussed in the Direct Testimony of Ms. Zich.

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

A. The test year forecast revenue requirements include a $15.0 million increase in Distribution operating expenses. This increase is due to an increase in the cost of labor over the last decade, as well as increases in the number and cost of Damage Prevention (Gopher One Call) locate work. Additional costs of maintaining the natural gas system have increased since our last rate case. Additional information regarding Distribution O&M is discussed in the Direct Testimony of Ms. Zich.

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

A. The test year forecast revenue requirements include a $5.7 million increase in A&G operating expenses. This increase is due to increased investments in Business Systems and Enterprise Security related to the Company's additional investments in the customer experience, software licensing cost increases, and networking costs. Additional information regarding Business Systems O&M is discussed in the Direct Testimony of Mr. Remington.

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

A. As discussed by Company witness Ms. Jannell E. Marks, actual sales have increased due to customer growth and use per customer increases, offset somewhat by anticipated reductions in throughput in 2021 and 2022. Consequently, the Company's retail revenues have increased by $23.7 million since the 2010 test year, decreasing the 2022 revenue deficiency.

Q. ARE THE FUNCTIONAL CLASS CATEGORIES OF OPERATING EXPENSE COMPARABLE BETWEEN THE 2022 TEST YEAR AND THE 2010 TEST YEAR?

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

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

A. No. Although the cost of fuel is considered an operating expense, recovery occurs through the Company's separate purchased gas adjustment (PGA) mechanism and true-up process.

III. SUPPORTING INFORMATION

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

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

A. Data Provided and Selection of the Test Year

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

A. In this section, I will:

- identify the supporting financial information and related fiscal periods that we are providing in connection with the 2022 test year forecast; and

- demonstrate that the supporting financial information and related fiscal periods that we are presenting provide appropriate information and facilitate review of our test year forecast.

1) Overview

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

A. Following the Commission's rules, financial data is provided for 2020 (the most recent fiscal year), 2021 (the projected fiscal year), and 2022 (the test year). In addition, we provide financial data to support the test year forecast. The most recent fiscal year (calendar year 2020) reflects the Company's actual financial results. For the projected fiscal year 2021, actual financial results through June 2021 are provided as rate base data, operating expenses and revenues. Forecast projections are provided for the remainder of 2021. The test year forecast reflects the Company's most recent available budget data.

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

I also provide schedules showing: the actual unadjusted average rate base consisting of the same rate base components; unadjusted operating income; overall rate of return; the calculation of required income; and the income deficiency and revenue requirements for the most recent fiscal year (2020), the projected fiscal year (2021), and the test year (2022).

2) *Test Year Forecast*

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

A. Calendar year 2022 was selected as the test year for this filing using Xcel Energy's most recent available budget data for the first year of the budget cycle. Use of a fully projected calendar test year (2022) is consistent with longstanding practice and precedent in the Company's rate cases before the Commission.

The 2022 Budget is supported by Company witness Ms. Melissa L. Ostrom's Direct Testimony and provided in Volumes 5 (Budget Summary and Documentation) and 6 (Budget Documentation) of the Application.

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

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

- Cost of capital to reflect the most currently available data;
- Current customer count and sales information and expected trends that might indicate that adjustments to the sales and customer count forecasts are needed;
- Assumptions used for calculating Qualified Pension, FAS 106 retiree medical and FAS 112 post-employment benefits expense based on information as of December 31, 2021;
- O&M active health care may be updated to reflect actual 2021 active medical and pharmacy incurred claims;

- Property tax forecasts based upon property tax data that will become available during 2022.

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

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

3) Supporting Information and the 2022 Projected Test Year

Q. WHY DOES THE COMPANY USE 2020 AS ITS MOST RECENT FISCAL YEAR INSTEAD OF 2021?

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

> Most recent fiscal year" is the *utility's prior fiscal year [here, 2020]* *<u>unless</u>* notice of a change in rates is filed with the commission within the last three months of the current fiscal year *and at least nine months of historical data is available for presentation of current fiscal year financial information*, in which case the most recent fiscal year is deemed to be the current fiscal year [here 2021]. (Emphasis added.)

In this proceeding, the Company's most recent fiscal year is 2020, and its current fiscal year is 2021. The Company's "most recent fiscal year" is also 2020, as the two exceptions to the rule that would instead convert 2021 into the most recent fiscal year are not fulfilled here. While the Company is filing this rate case within the last three months of 2021, nine months of actual 2021 data is "not available for presentation." Since that requirement cannot be met, the plain language of the Rule directs the Company to use 2020 as the most recent fiscal year, consistent with the Company's long standing approach.

Nothing in the Rule requires the Company to delay its filing until additional 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.

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

A. Yes. In our electric rate case in Docket E002/GR-12-961, the Administrative Law Judge (ALJ) found that the Company's practice was consistent with its filings in past rate cases and was in compliance with Commission rules. Therefore, the ALJ supported,[1] and the Commission adopted, the Company's use of a fully projected test year. Most recently, we utilized actual 2014 data as the "most recent fiscal year" data in Docket No. E002/GR-15-826, as 2015 actual data was not available for presentation at the time of that filing. There was no issue with that approach in that case.[2]

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

[2] We recently noted that in one case, the Commission issued a rule variance in order to permit a utility to utilize the last full calendar year (2020 data) as the "most recent fiscal year" for a rate case filed in the last two months of 2017. *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota,* ORDER ACCEPTING FILING, SUSPENDING RATES, EXTENDING TIMELINE, AND VARYING RULE, Docket No. G011/GR-15-736 (Dec. 5, 2017). We do not believe a variance is necessary here, just as it has not been necessary in prior NSPM rate cases, because utilizing 2018 data is consistent with the Minnesota Rule under the circumstances of this filing. But if the Commission determines that a variance is necessary, the Company requests a variance under Minn. R. 7829.3200, because (i) the Company began preparing this rate case filing several months before the requisite data was available for 2019, and it would be an excessive burden on the utility to wait to file the

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

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

- Volume 3, Required Information, Section II:
  - Tab 2, Jurisdictional Financial Summary Schedules, Schedule A-1
  - Tab 3, Rate Base Schedules, Section A, Schedule A-1
  - Tab 3, Rate Base Schedules, Section B, Schedule B-2
  - Tab 3, Rate Base Schedules, Section E, Schedule E, Page 2
  - Tab 4, Operating Income Schedules, Section A, Schedule A-1
  - Tab 4, Operating Income Schedules, Section B, Schedule B-1
  - Tab 4, Operating Income Schedules, Section C, Schedules C-1 and C-3
  - Tab 4, Operating Income Schedules, Section F, Schedule F, Page 2
  - Tab 5, Rate of Return Cost of Capital Schedules, Sections A-D
- Exhibit___(BCH-1), Schedule 7, Comparison of Detailed Rate Base Components
- Exhibit___(BCH-1), Schedule 8, Comparison of Detailed Income Statement Components

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case or refile the case when 2019 data is available (and would not align with a calendar year test year); (ii) granting the variance would not adversely affect the public interest, because NSPM has used this approach in the past with the same extensive data, and it has resulted in just and reasonable rates; and (iii) granting the variance would not conflict with standards imposed by law.

B. Jurisdictional Cost of Service Study

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

A. In this section, I will explain the jurisdictional cost of service studies that we prepared for the test year forecast.

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

A. A summary of the jurisdictional cost of service study for the test year forecast is provided in Schedule 2, Summary of Revenue Requirements. The complete jurisdictional cost of service study for the test year forecast is provided in Schedules 3, Cost of Service Study Summary, and in Volume 4 (Test Year Workpapers) of this filing and includes all the adjustments discussed in my Direct Testimony.

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

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

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

- The Rate Base Summary for the Minnesota jurisdiction gas operations is shown on Page 1. It provides the assumed capital structure, including the earned overall rate of return on rate base and the earned ROE. The Rate Base Summary references a calculation of cash working capital, which is detailed in Exhibit ___(BCH-1), Schedule 4 (Cash Working Capital), and Volume 4, Section P10, Cash Working Capital.

- An Income Statement for the Minnesota jurisdiction gas operations is shown on Page 2 and Page 3. The income statement shows the determination of total operating income at present authorized retail rates. The Income Statement references calculations for federal and state income taxes, which are detailed on Page 3.
- The Revenue Requirement and Return Summary for the Minnesota jurisdiction gas operations is shown on Page 4. It shows the revenue deficiency that needs to be recovered to enable the Minnesota jurisdiction gas operations to earn the requested rate of ROE and the total revenue requirements and the percent of increase that would result by increasing retail billing rates by the amount of the revenue deficiency.

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

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

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

A. The amount of interest deducted for income tax purposes is the weighted cost of debt capital multiplied by the average rate base. This is sometimes called "interest synchronization." The calculation for the interest synchronization in the test year is provided in Schedule 3, Cost of Service Summary, line 97.

Q. WHICH SCHEDULES TO YOUR TESTIMONY ARE RELATED TO RATE BASE?

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

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

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

IV. RATE BASE

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

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

Q. IS THE COMPANY'S PROJECTED 2022 TEST YEAR RATE BASE REASONABLE FOR PURPOSES OF DETERMINING FINAL RATES IN THIS PROCEEDING?

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

Q. PLEASE EXPLAIN WHAT RATE BASE REPRESENTS.

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

Q. PLEASE IDENTIFY THE MAJOR COMPONENTS OF THE PROJECTED 2022 TEST YEAR RATE BASE.

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

- Net Utility Plant
- Construction Work in Progress
- Accumulated Deferred Income Taxes
- Other Rate Base

Q. HOW DOES THE COMPANY CALCULATE RATE BASE?

A. The Company's rate base can be expressed as follows:

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

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

Plant	$1,788,364	(per BCH-1, Schedule 3, Page 1, Line 23)
Reserve	(691,832)	(per BCH-1, Schedule 3, Page 1, Line 24)
ADIT	(202,226)	(per BCH-1, Schedule 3, Page 1, Line 31)
CWIP	27,627	(per BCH-1, Schedule 3, Page 1, Line 26)
Other Rate Base	12,515	(per BCH-1, Schedule 3, Page 1, Line 42)
Rate Base	$934,448	(thousands of dollars)

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

A. Schedule 7, Comparison of Detailed Rate Base Components, provides a detailed statement of the rate base components. Page 1 provides a comparison of the rate base components for the 2022 test year, to the 2010 test year established in Docket No. G002/GR-09-1153. Page 2 provides the rate base components for the test year forecast.

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 test year average Construction Work in Progress (CWIP) for the Minnesota jurisdiction and Total Company, before and after making proposed test period adjustments. Page 3 shows the test year accumulated deferred income taxes (ADIT) for the Minnesota jurisdiction and Total Company, before and after making proposed test period adjustments.

Schedule 10, 2022 Test Year Rate Base Adjustment Schedule, are a bridge schedule showing the 2022 unadjusted rate base, each proposed rate base adjustment, and the resulting proposed 2022 test year rate base.

A. Net Utility Plant

Q. WHAT DOES NET UTILITY PLANT REPRESENT?

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

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

A. The net utility plant is included in rate base at depreciated original cost reflecting the simple average of projected net plant balances at the beginning and end of the 2022 test year. Such treatment is consistent with the method employed in the most recent Minnesota gas rate case.

Q. WHAT HISTORICAL BASE DID THE COMPANY USE AS A STARTING POINT TO DEVELOP THE PROJECTED NET PLANT BALANCES FOR THE BEGINNING OF THE 2022 TEST YEAR?

A. The historical base used for the beginning of the 2022 test year was the Company's actual net investment (Plant in Service less Accumulated Depreciation) on the Company's books and records as of June 30, 2021 plus the forecast for the remaining months of 2021.

Q. ON WHAT BASIS WERE NET PLANT BALANCES PROJECTED FOR THE END OF THE 2022 TEST YEAR?

A. 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 balances, adjusted for retirements, depreciation, salvage and removal costs projected to occur during the 2022 test year.

Q. WHAT WAS THE AVERAGE NET UTILITY PLANT INCLUDED IN THE 2022 TEST YEAR RATE BASE?

A. The average net utility plant included in the 2022 test year rate base is $1.1 billion, as shown on Schedule 7, Comparison of Detailed Rate Base Components. This is comprised of an average plant balance of $1.8 billion as detailed on Schedule 7, minus an average depreciation reserve of $0.7 billion, also shown by component on Schedule 7.

B. Construction Work In Progress

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

A. 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.

Q. HAS CWIP BEEN INCLUDED IN THE 2022 TEST YEAR RATE BASE?

A. Yes. CWIP is included in rate base with a corresponding offset of AFUDC added to operating income. The rate base amount reflects a simple average of projected CWIP beginning and ending 2022 test year balances. This is consistent with the method employed in Minnesota and approved by the Commission in the Company's last rate case and matches the use of an average rate base. The CWIP and AFUDC determinations for rate base are discussed in the Direct Testimony of Company witness Ms. Laurie J. Wold.

Q. HOW WERE THE 2022 TEST YEAR BEGINNING AND ENDING CWIP BALANCES DETERMINED?

A. The beginning balance for CWIP was the June 30, 2021 historical balance. The beginning CWIP balance was adjusted to reflect projected construction expenditures, AFUDC, and transfers to Plant in Service during the remainder of 2021 and in 2022 to obtain the beginning and ending 2022 test year CWIP balance. These projections were developed from the Company's 2022 capital budget.

C. Accumulated Deferred Income Taxes

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

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

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

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

Q. WHAT AMOUNT OF ADIT WAS DEDUCTED TO ARRIVE AT THE 2022 TEST YEAR RATE BASE?

A. As shown on Schedule 7, Comparison of Detailed Rate Base Components, $202.2 million was deducted. This amount reflects a simple average of the projected beginning and ending 2022 test year ADIT balances and incorporates Internal Revenue Service (IRS) tax regulations. Specifically, Sec. 1.167(l) of the tax code defines a pro-rated schedule for the extent average accumulated deferred income taxes can be used to reduce rate base to comply with the tax normalization requirements of the Code when forecast information is used to set rates. This is consistent with the method employed in Minnesota and approved by the Commission in the Company's most recent rate cases. Details related to ADIT are provided in Schedule 9, Rate Base, CWIP and ADIT Summary, on Page 4 of 4, and are discussed in more detail by Ms. Wold.

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

A. The Commission's Order in Docket No. E,G999/CI-17-895 directed the Company's amortizations of excess ADIT, which are included in the amounts shown on Schedule 7, Comparison of Detailed Rate Base Components, Pages 1 and 2. Additional information regarding the TCJA's effect on the deferred taxes associated with plant assets is addressed by Ms. Wold. Support for the excess ADIT can be found in Volume 4, Section III Rate Base (Plant), Tab P2-3.

D. Other Rate Base

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

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

Q. PLEASE EXPLAIN WHAT WORKING CAPITAL REPRESENTS.

A. Working Capital is the average investment in excess of net utility plant provided by investors that is required to provide day-to-day utility service. It includes items such as materials and supplies, fuel inventory, prepayments, and various non-plant assets and liabilities. The net cash requirement (referred to as Cash Working Capital) is shown separately.

Q. HOW WERE 2022 TEST YEAR MATERIALS AND SUPPLIES REQUIREMENTS CALCULATED?

A. The Materials and Supplies amounts shown on Schedule 3, Page 1, Cost of Service Study Summary, are based on the 13-month average balances ending June 30, 2021, the most recent data available. The Materials and Supplies average balance are included on Schedule 3, Cost of Service Study Summary, Page 1, Line 34.

Q. HOW WERE 2022 TEST YEAR GAS-IN-STORAGE REVENUE REQUIREMENTS DETERMINED?

A. The Gas-In-Storage amount shown on Schedule 3, Cost of Service Study Summary, Page 1, is developed based on the thirteen-month average balances used in the 2022 gas storage budget. The 2022 Test Year rate base amount for Gas-In-Storage are included on Schedule 3, Cost of Service Study Summary, Page 1, Line 35.

Q. HOW WERE 2022 TEST YEAR NON-PLANT ASSETS AND LIABILITIES DETERMINED?

A. These balances as shown on Schedule 3, Page 1, Cost of Service Study Summary, represent 2022 test year estimates of these balances. Any book/tax timing differences associated with these items have been reflected in the determination of current and deferred income tax provision and ADIT balances previously discussed. The Non-Plant Assets and Liabilities average balance are included on Schedule 3, Cost of Service Study Summary, Page 1, Line 36.

Q. ARE THERE ANY NON-PLANT ASSETS OR LIABILITIES FOR WHICH THE COMPANY IS NOT REQUESTING RECOVERY IN BASE RATES?

A. Yes. In Docket No. G-999/CI-21-135, the Commission approved amortization and recovery of gas costs associated with Winter Storm Uri over 27 months, subject to a prudency review proceeding that is currently pending. The Company is carrying these costs over this period without seeking to recover a carrying charge, which presents significant impact to the Company. In light of the pending prudency docket, the Company is not including this regulatory asset in rate base in this rate case. The Company will include these amounts in its jurisdictional annual report.

Q. HOW WERE 2022 TEST YEAR PREPAYMENTS AND OTHER WORKING CAPITAL ITEMS DETERMINED?

A. Prepayments and Other Working Capital, such as customer advances and deposits, are based on the actual 13-month average balances during the period ended June 30, 2021, as a proxy for the 2022 test year. The unamortized balances included in this section are based on the amortization schedules as described in Section IV. The Prepayments and Other Working Capital average balances are included on Schedule 3, Cost of Service Study Summary, Page 1, Lines 37-40.

Q. HOW WERE THE TEST YEAR CASH WORKING CAPITAL REQUIREMENTS DETERMINED?

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

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

A. Yes. The test year cash working capital has been calculated consistent with methods accepted in our most recent Minnesota gas rate case.

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

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

Q. HAS XCEL ENERGY'S LEAD/LAG STUDY BEEN UPDATED SINCE THE LAST GAS RATE CASE?

A. Yes. The Company has updated the lead/lag study for the calculation of the lead and lag days for all categories through year end 2020, using the methodology for calculating the lead/lag days consistent with the Company's prior electric and gas regulatory filings. The results of the updated lead/lag study for gas operations were incorporated into the Minnesota jurisdiction cash working capital calculations as shown on Schedule 4, Cash Working Capital, Page 1.

Q. WHAT ARE THE TEST YEAR CASH WORKING CAPITAL AMOUNTS?

A. The $13.7 million included as reduction in average rate base in the test year are based on the results of our lead/lag study prepared consistently with previous rate cases.

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

A. Yes. The 2022 test year Cash Working Capital balance of $13.7 million represents a $9.8 million increase compared to the 2010 test year. This increase has the effect of reducing rate base.

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

A. The change in Cash Working Capital from the 2010 level is primarily due to the net changes in the average expense lead and revenue lag days between the two periods. Average revenue lag days decreased to 38 in 2022 from 43 in 2010, meaning the Company's revenues are being collected on average 4 days quicker in 2022 than in 2010. The Company's average expense lead days increased to 48 in 2022 from 45 in 2010, meaning that the Company's cash outlay for paying expenses increased by an average of 3 days. Overall, cash inflows from revenue collections exceed the longer time frame for disbursing cash, giving rise to a negative cash working capital balance to be included in rate base.

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

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

V. INCOME STATEMENT

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

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

Q. IS THE COMPANY'S PROPOSED TEST YEAR INCOME STATEMENT REASONABLE FOR DETERMINING FINAL RATES IN THIS PROCEEDING?

A. Yes. The proposed test year income statement for the Company's Minnesota jurisdiction gas operations were developed on sound ratemaking principles in a manner similar to prior Company gas rate cases.

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

A. The following are the major components of the test year forecast income statements:

- Revenues
- Operating and Maintenance Expenses
- Depreciation Expense
- Taxes
- AFUDC

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

A. Schedule 11, 2022 Income Statement Adjustment Schedule, is a bridge schedule that shows the unadjusted income statement, each proposed income statement adjustment, and the resulting proposed income statement for the test year. Schedule 11 also includes the revenue deficiency amount for each item included in this schedule.

Schedule 8, Comparison of Detailed Income Statement Components, provides a detailed statement of the income statement components. Page 1 provides a comparison of income statement components for the Company's last rate case filing to the 2022 test year assuming final rates.

A. Revenues

Q. HOW DOES THE COMPANY PRESENT ITS PROJECTED SALES FOR THE TEST YEAR CONSIDERED?

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

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

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

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

A. Yes. The test year includes items such as revenues from limited firm standby gas customers, late payment fees, service activation fees, reconnection fees and others.

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

A. Yes. We have excluded the revenues and expenses associated with Commission-approved non-regulated business activities (i.e. Homesmart) from the test year cost of service. Because these activities are recorded in below the line accounts, they were not included in the test year.

B. Operating and Maintenance Expenses

Q. HOW DOES THE COMPANY CALCULATE OPERATING EXPENSES?

A. The Company's operating expenses can be expressed as follows:

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

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

Table 6

Operating Expenses

	Item	2022 Test Year Amount ($000s)	Exhibit__ (BCH-1), Sch. 3 Reference
	Operating Expense	$423,052	Page 2, Line 61
plus	Depreciation	53,130	Page 2, Line 63
plus	Amortization	167	Page 2, Line 64
plus	Other Taxes	25,056	Page 2, Line 120
plus	Income Tax	3,891	Page 3, Line 121
equals	Total Expense	$505,296	Page 3, Line 125

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

A. The principle expense categories are:

- Purchased Gas
- Gas Production and Storage

- Gas Transmission
- Gas Distribution
- Customer Accounting
- Customer Service & Information
- Sales, Economic Development and Other
- Administrative and General

Q. HOW ARE PURCHASED GAS COSTS TREATED?

A. Purchased Gas costs are collected through the Purchased Gas Adjustment rider (PGA). Those costs are fully offset by revenues from the PGA, and therefore have no impact on the 2022 test year revenue deficiency.

Q. HAS THIS CHANGED SINCE THE LAST RATE CASE?

A. No.

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

A. Gas production costs are primarily the costs needed to operate and maintain the Company's gas production and storage assets, including its gas peaking plants and former MGP sites. These costs are budgeted through development of a production and storage system budget to serve the Company's natural gas customers in Minnesota and North Dakota. Please see Ms. Zich's testimony for additional details.

Q. HOW DOES NSPM DEVELOP ITS TEST YEAR GAS TRANSMISSION AND DISTRIBUTION EXPENSES?

A. Transmission and distribution expenses are the O&M costs associated with operating and maintaining our Minnesota gas transmission and distribution facilities. These costs and their development are detailed in the Direct Testimony of Ms. Zich.

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

A Customer Accounting O&M cost is associated with providing meter reading, billing, credit and collections, bad debt expense, contact center and operational support services. These costs are developed through the Customer Care budget prepared for both the NSPM electric and gas utilities. These costs and their development are detailed in the Direct Testimony of Company witness Mr. Christopher C. Cardenas. The allocation of these costs to the gas utility and then to the Minnesota jurisdiction is addressed in Section VI of my Direct Testimony.

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

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

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

A. No. The Company records all lobbying costs to below the line accounting, FERC account 426.4, Expenditures for Certain Civic, Political and Related Activities. The Company prepares the unadjusted expenses for the test year using queries that restrict the data to only above-the-line accounts (FERC Accounts 500 through 935). Thus, no adjustment to the cost of service for lobbying costs is required, as these below the line amounts are not used in our development of the test year cost of service. We have also excluded the portion of organizational dues associated with lobbying activities. Company witness Mr. W. Kile Husen addresses our efforts to identify and remove lobbying expenses in his Direct Testimony.[3]

C. Depreciation Expense

Q. WHAT IS THE BASIS OF THE DEPRECIATION RATES AND EXPENSE USED IN THE 2022 TEST YEAR?

A. Depreciation expense for the 2022 test year base data reflects the Company's depreciation rates last certified by the Commission for the 2020 Average 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) along with the proposed gas plant life extension. These adjustments are discussed in Section VII (adjustments 4, 5 and 9). Ms. Wold

[3] 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.

discusses the Company's depreciation expense and remaining lives proposals in her Direct Testimony.

D. Taxes

Q. WHAT TAX EXPENSES ARE INCLUDED IN THE 2022 TEST YEAR INCOME STATEMENT?

A. We have line items for Property; Income Taxes including Deferred Income Tax, Investment Tax Credits and Federal and State Income Tax; and Payroll. The State and Federal income taxes are calculated in Schedule 3, Cost of Service Study Summary for 2022 test year, starting on Page 2 of 4.

Q. HOW ARE PROPERTY TAXES DETERMINED FOR THE JURISDICTION?

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

Q. HOW ARE INCOME TAXES DETERMINED FOR THE JURISDICTION?

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

Q. DOES THE COST OF SERVICE REFLECT ANY POTENTIAL FEDERAL OR STATE CORPORATE TAX RATE CHANGES DURING THE TEST YEAR?

A. Not at this time. When the cost of service was prepared, federal legislation around a potential tax increase had been proposed, but the timing or the effective date is still uncertain. In addition, any state or federal tax change proposal would need to be passed into law before it would take effect.

Q. WHAT IMPACT WOULD A FEDERAL TAX RATE INCREASE HAVE ON THE COST OF SERVICE?

A. The specific impacts to the cost of service would depend on the actual legislation that is enacted, if any. However, at a high level, an increase in the corporate income tax rate is expected to increase current and deferred income tax expense and ADIT leading to a net increase in the cost of service. Similarly, a decrease in the corporate income tax rate is expected to decrease current and deferred income tax expense and ADIT leading to a net decrease in the cost of service consistent with the TCJA impacts on the cost of service.

Q. WHAT DOES THE COMPANY PROPOSE IF INCOME TAX RATES WERE TO CHANGE DURING THE PENDENCY OF THE RATE CASE?

A. At this time, it is not clear if or when federal and/or state tax rates may change, but the Company would likely need to work with the Commission to seek relief in such a change occurs. In the event of new tax legislation, it is also possible other Minnesota utilities will need similar relief. One option may be to institute a tracker, similar to how the TCJA was addressed in 2018, that would track and defer the difference between the cost of service used to set final base rates in this rate case filing with a cost of service adjusted for any income tax changes. We would then address the net regulatory asset or liability in our next rate case.

E. AFUDC

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

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

VI. UTILITY AND JURISDICTIONAL ALLOCATIONS

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

A. In this section I will:

- explain, at a high level, why it is necessary for the Company to allocate costs among its affiliates and between the jurisdictions in which it does business;
- describe the utility and jurisdictional allocations that are used in determining the revenue requirement.

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

A. Whenever services or facilities are shared between NSPM and an affiliate, it is necessary that the appropriate costs related to those services or facilities be assigned or allocated to the appropriate entity. Company witness Mr. Ross Baumgarten, in his Direct Testimony, explains the allocations for services and facilities shared between NSPM and an affiliate. Additional information regarding this process and the reason for selecting a particular allocator is also included in the Cost Assignment and Allocation Manual (CAAM) submitted with this application as Mr. Baumgarten's Exhibit___(RLB-1), Schedule 3.

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

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

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

A. Yes. The Company operates in two gas jurisdictions: Minnesota and North Dakota. Thus, it is necessary to allocate or assign costs appropriately between jurisdictions.

Q. HOW ARE COSTS ASSIGNED AND ALLOCATED?

A. The expense budgets relied upon to develop test-year income statement items were generally prepared on a functional basis (*i.e.* Production, Transmission, Distribution, Customer Accounts, Customer Information, Sales, Administrative and General). These functional amounts are directly assigned to the Minnesota jurisdiction gas utility operations where appropriate or allocated based on cost causation.

Detailed records are maintained on a functional basis (*i.e.* Production, Transmission, Distribution, etc.). The capital budgets, from which the projected plant balances in rate base were developed, are also prepared on a functional basis. These functional amounts are assigned to the appropriate jurisdiction directly or allocated based on the use of such assets in providing gas service in a particular jurisdiction and the underlying elements of cost causation.

Generally, all production and storage plant is allocated to jurisdiction using the jurisdictional design day allocator. Production and storage O&M expense also is allocated using the jurisdictional design day allocator.

Mr. Baumgarten further explains assignment and allocation of costs in his Direct Testimony.

Q. HOW ARE THESE ALLOCATION FACTORS DEVELOPED?

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

Q. HOW ARE PURCHASED GAS COSTS ALLOCATED?

A. Purchased gas costs are direct assigned to the Minnesota and North Dakota gas jurisdictions based on estimated revenue collections.

VII. ANNUAL ADJUSTMENTS TO THE TEST YEAR

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

A. In this section of my testimony, I explain adjustments that affect our proposed test year revenue requirement. These adjustments were identified during our review of the 2022 budget and preparation for this case. An individual adjustment may be related to a previous Commission Order, reflect Commission policy or traditional ratemaking treatment, or may be proposed to address a situation particular to this rate case. In this section, I provide details related to each adjustment and explain why each is necessary in order to present a representative level of rate base or costs in the test year. I also identify where another Company witness provides information to explain and support the adjustment.

Q. HOW ARE THESE ADJUSTMENTS PRESENTED IN YOUR TESTIMONY?

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

Calculations), and certain adjustments that may be necessary for Rebuttal Testimony in this proceeding.

Q. PLEASE LIST THE 2022 TEST YEAR ADJUSTMENTS.

A. The following adjustments were made to rate base and the income statement where applicable. Rate base adjustments are shown on Schedule 10, Rate Base Adjustment Schedule. Income statement (revenue requirement) adjustments are shown on Schedule 11, Income Statement Adjustment Schedule. As a general note, all capital related revenue requirements shown on Schedule 11 are calculated at the last authorized rate of return. Exhibit___(BCH-1), Schedule 12, 2022 Adjustment Summary provides adjustment amounts for the test year, all capital related revenue requirements shown on Schedule 12 are calculated at the proposed rate of return. Precedential Adjustments are set forth in Table 7 below.

<u>Rate Case Adjustments</u>

1) Black Dog Pipeline
2) CIP Approved Program Costs
3) Credit Card Auto Pay Fees
4) Gas Depreciation Study TD&G
5) Gas Remaining Life Study
6) Incentive Compensation
7) New Area Surcharge
8) New Business CIAC
9) Gas Remaining Life Extension

Amortizations

10) Income Tax Tracker

11) Rate Case Expense

Rider Removals

12) GUIC Rider

13) SEP Rider

Secondary Cost of Service Calculations

14) ADIT Pro-Rate – IRS Required

15) Cash Working Capital

16) Change in Cost of Capital

17) Net Operating Loss

A. Precedential Adjustments

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

A. Table 7 below is a list of Precedential Adjustments and their associated revenue requirement impact, based on past rate case precedent and Commission policy:

Table 7

Precedential Adjustments

Record Type	MN Gas 2021 Test Year	Workpaper Reference
NSPM-Advertising (Trad)	($227,055)	WP-A1
NSPM-Assn Dues (Trad)	(11,250)	WP-A2
NSPM-Aviation	(144,010)	WP-A3
NSPM-Chamber of Commerce Dues	10,797	WP-A4
NSPM-Customer Deposits - A&G Expense (Trad)	2,489	WP-A5
NSPM-Donations (Trad)	40,198	WP-A6
NSPM-Econ Dev Donations (Trad)	7,015	WP-A7
NSPM-Econ Develop (Trad)	(15,925)	WP-A8
NSPM-Employee Expenses	(181,185)	WP-A9
NSPM-Foundation Admin	(10,731)	WP-A10
NSPM-Incentive Pay	(113,849)	WP-A11
NSPM-Incentive Pay Remove Long Term	(764,271)	WP-A12
NSPM-Pension Non-Qual Restoration Removal	(79,791)	WP-A13
NSPM-Pension Non-Qual SERP Removal	(22,574)	WP-A14
Sub-Total Precedential	**($1,510,143)**	

Q. How does the Company provide support for these Precedential Adjustments?

A. Treatment of these precedential adjustments has become quite consistent in a number of cases before the Commission over the past several years. As such, the Company has provided the adjustments themselves in Schedules to my Direct Testimony, and support for these adjustments, including a detailed description of each adjustment and supporting materials, in the workpapers identified in Table 7 above. This organization is intended to facilitate the review of and full support for each adjustment within the identified workpaper.

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

A. Regulatory treatment of these precedential adjustments decreases the cost of service by approximately $1.5 million. However, these adjustments reflect actual costs the Company expects to incur to provide gas service to our customers.

Q. HOW IS THE COMPANY INCORPORATING THESE ADJUSTMENTS INTO THE TEST YEAR?

A. These precedential adjustments are combined in one column matching the Total row in Table 7 above to Schedule 11, Income Statement Adjustment Schedule. In total, these precedential adjustments represent a decrease in our rate request compared to our budgeted costs. The detail of the precedential adjustments in bridge schedule format can be seen in Exhibit___(BCH-1), Schedule 13, Precedential Adjustment Detail. In addition, as noted above, each respective workpaper referenced above contains a detail description of the adjustment, including the past precedent and related Commission Orders or Policy Statements.

B. Rate Case Adjustments

1) Black Dog Pipeline

Q. PLEASE DESCRIBE THE BLACK DOG PIPELINE ADJUSTMENT.

A. We have adjusted the 2022 test year to remove costs that exceeded our main and service extension justification.

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

- Schedule 10, page 1, row 46, column 5,
- Schedule 11, page 1, row 40, column 6,
- Schedule 12, page 1, row 19, column 5,
- Volume 4, Section VIII Adjustments, Tab A15.

2) CIP Approved Program Costs

Q. PLEASE DESCRIBE THE CIP APPROVED PROGRAM LEVELS ADJUSTMENT.

A. The test year CIP expenses and corresponding revenues have been set at the 2022 level of $18.668 million as proposed in Docket E,G002/CIP-20-473.

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

- Schedule 11, page 1, row 40, column 7,
- Schedule 12, page 1, row 20, column 5,
- Volume 4, Section VIII Adjustments, Tab A16.

3) Credit Card Auto Pay Fees

Q. PLEASE DESCRIBE THE CREDIT CARD AUTOPAY ADJUSTMENT.

A. The credit card autopay adjustment is a proposal the Company is making in the 2022 test year to improve this payment option for customers and include credit card processing costs in base rates rather than have customers continue to be charged on a per-transaction basis. The Company's proposal also includes a tracker for these costs, which I discuss in further detail in Section VIII, Costs Recovered in Riders and Trackers, Part E. Trackers and Deferrals, of my Direct Testimony. Mr. Cardenas also discusses the Company's proposal in his Direct Testimony.

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

- Schedule 11, page 1, row 40, column 8,
- Schedule 12, page 1, row 21, column 5,
- Volume 4, Section VIII Adjustments, Tab A17.

4) Gas Depreciation Study TD&G

Q. PLEASE DESCRIBE THE GAS DEPRECIATION STUDY TD&G ADJUSTMENT.

A. We have adjusted the 2022 test year to include the impact of Docket No. E,G002/D-21-584. The new depreciation rates as proposed in the compliance filing would increase total Company depreciation expense by $0.7 million. We have proposed the new rates to be effective as of January 1, 2022. The 2021 docket is still pending final approval. However, the Test Year calculations assume that this filing will be adopted in its entirety. To the extent that these are not adopted per the filing, the Company will submit updates in rebuttal testimony. Support for these changes are provided by Ms. Wold in her Direct Testimony.

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

- Schedule 10, page 1, row 46, column 6,
- Schedule 11, page 1, row 40, column 9,
- Schedule 12, page 1, row 22, column 5,
- Volume 4, Section VIII Adjustments, Tab A18.

5) Gas Remaining Life Study

Q. PLEASE DESCRIBE THE GAS REMAINING LIFE STUDY ADJUSTMENT.

A. We have adjusted the 2022 test year to include the approved changes of Docket No. E,G002/D-19-723. The Commission's Order was issued on September 2, 2021, after the base forecast was prepared; therefore, it was necessary to make an adjustment to reflect the approved changes. Support for the changes that were approved are provided by Ms. Wold in her Direct Testimony.

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

- Schedule 10, page 1, row 46, column 6,
- Schedule 11, page 1, row 40, column 9,
- Schedule 12, page 1, row 23, column 5,
- Volume 4, Section VIII Adjustments, Tab A19.

6) Incentive Compensation

Q. PLEASE DESCRIBE THE INCENTIVE COMPENSATION ADJUSTMENT IN THE 2022 TEST YEAR.

A. We have adjusted test year costs to include the budgeted costs of the long-term incentive compensation related to Company achievement of environmental goals and time-based employee retention incentives. Ms. Lowenthal discusses incentive compensation in her Direct Testimony.

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

- Schedule 11, page 1, row 40, column 10,
- Schedule 12, page 1, row 24-25, column 5,
- Volume 4, Section VIII Adjustments, Tab A20-A21.

7) New Area Surcharge

Q. PLEASE DESCRIBE THE NEW AREA SURCHARGE (NAS).

A. The NAS projects involve major expansions of service facilities that do not meet the general cost justification criteria in the Company's gas service tariffs. A NAS is a separate charge that is added to customer bills for a specified period to supplement recovery of the cost of the new area expansion.

Q. PLEASE DESCRIBE THE NEW AREA SURCHARGE ADJUSTMENT.

A. The NAS adjustment removes capital expenditures and other related expenses that will be collected through the new area surcharge.

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

- Schedule 11, page 1, row 40, column 11,
- Schedule 12, page 1, row 26, column 5,
- Volume 4, Section VIII Adjustments, Tab A22.

8) New Business Contributions in Aid of Construction (CIAC)

Q. PLEASE DESCRIBE THE NEW BUSINESS CIAC ADJUSTMENT.

A. The Company analyzed its new business development practices in light of the Commission Order in Docket No. G999/CI-90-563, as described in the direct testimony of Company witness Mr. Scott S. Hults. This analysis identified certain instances where new business CIAC that would have been justified was not collected.

Q. HOW DOES THIS ANALYSIS IMPACT THE 2022 TEST YEAR?

A. Based on the findings of this analysis, an adjustment was made to reflect the reduction in plant in service and other plant related items had the Company collected the CIAC.

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

- Schedule 10, page 1, row 46, column 7,
- Schedule 11, page 1, row 40, column 12,
- Schedule 12, page 1, row 27, column 5,
- Volume 4, Section VIII Adjustments, Tab A23.

9) Gas Remaining Life Extension

Q. PLEASE DESCRIBE THE GAS REMAINING LIFE EXTENSION ADJUSTMENT.

A. This adjustment reflects depreciation changes due to the extension of the service lives of all peaking plants to December 2041. Support for these changes are provided by Ms. Wold in her Direct Testimony.

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

- Schedule 10, page 1, row 46, column 8,
- Schedule 11, page 1, row 40, column 13,
- Schedule 12, page 1, row 28, column 5,

- Volume 4, Section VIII Adjustments, Tab A24.

C. Amortizations

10) Income Tax Tracker

Q. Please describe the Income Tax Tracker amortization.

A. The Company has concluded tax audits with the IRS and the Minnesota Department of Revenue for tax years ended 2010 through 2016. As a result of the audits, the Company paid tax and interest on the disputed amounts. In the Company's 1992 electric rate case, Docket No. E002/GR-92-1185, and in Docket Nos. E002/M-93-1328, E002/M-04-1605, E002/M-05-1471 and E002/GR-12-961, the Commission authorized deferred accounting status of both tax credits and debits. Consistent with this precedent, we propose to collect this amount over the three-year period 2022-2024

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

- Schedule 10, page 1, row 46, column 9,
- Schedule 11, page 1, row 40, column 14,
- Schedule 12, page 1, row 31, column 5,
- Volume 4, Section VIII Adjustments, Tab A25.

11) Rate Case Expense

Q. PLEASE DESCRIBE HOW RATE CASE EXPENSES WERE ESTIMATED.

A. We built the 2022 rate case budget based upon a combination of our plans for outside experts, expected regulatory and legal fees and estimates for administrative costs such as required notices. The estimated total rate case expense level for this rate case is $3.5 million to be amortized over the three-year period 2022-2024.

Q. WHAT ELSE IS INCLUDED IN THE REQUESTED RATE CASE EXPENSE AMOUNT IN THE 2022 TEST YEAR?

A. Based on the PUC Order in Docket No. G-002/GR-09-1153, current rate case expenses have been offset by deferred levels recovered for rate case expenses after the four year amortization period in 09-1153. The deferred amount reflects the annual collection amount recovered over eight years. The net amount of current year rate case expenses and deferred levels impacts the test year revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 40, column 15,
- Schedule 12, page 1, row 32, column 5,
- Volume 4, Section VIII Adjustments, Tab A26.

D. Rider Removals

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

A. The Company currently uses four cost recovery riders:

- Gas Utility Infrastructure Cost (GUIC) Rider,
- Conservation Improvement Program (CIP) Rider,
- Purchased Gas Adjustment (PGA)
- State Energy Policy (SEP) Rider,

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

A. We propose to:

- Continue use of the GUIC Rider for recovery of costs,

- Continue use of the CIP Rider and PGA in their current forms,
- Discontinue the use of the SEP Rider.

Below I discuss adjustments to remove costs related to the GUIC from the revenue requirement to reflect these rider proposals. No adjustments are needed to the 2022 test year for the CIP, PGA, or SEP Riders as discussed in detail in Section VIII of my direct testimony.

12) GUIC Rider

Q. WHAT IS THE GUIC RIDER?

A. Minnesota Statute § 216B.1635 (the GUIC Statute) allows a utility to petition the Commission for the recovery of "gas utility infrastructure costs." According to the GUIC statute, GUIC costs can relate to two different types of "gas utility projects"—generally speaking, (1) replacement of natural gas facilities located in the public right-of-way by the construction or improvement of a highway, road, street, public building, or other public work by or on behalf of the United States, the state of Minnesota or a political subdivision or (2) replacement or modification of existing natural gas facilities as required by a federal or state agency.

Q. IS THE COMPANY PROPOSING CONTINUED USE OF THE GUIC RIDER DURING THE TEST YEAR?

A. Yes. We propose continued use of the GUIC Rider during the test year for project expenditures not placed in service as of December 31, 2021. We propose to recover the capital-related revenue requirements and property taxes as well as incremental operating and maintenance expenses. Therefore, we have not included any expenditures for these projects in the 2022 forecast as a part of our 2022 test year.

Q. PLEASE DESCRIBE THE GUIC RIDER REMOVAL ADJUSTMENT.

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

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

A. This adjustment decreases the test year rate base by $37.9 million in 2022. The adjustment has a net zero impact on the test year revenue requirements, as we expect full recovery. Support for these amounts can be found on:

- Schedule 10, page 1, row 46, column 10,
- Schedule 11, page 1, row 40, column 16,
- Schedule 12, page 1, row 35, column 5,
- Volume 4, Section VIII Adjustments, Tab A27.

Q. ARE THE RIDER REMOVALS BASED ON THE SAME DATA USED IN THE 2022 RIDER FILINGS?

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

E. Secondary Cost of Service Calculations

13) ADIT Pro-Rate – IRS Required

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

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

This secondary calculation limits the ADIT deduction from rate base by applying the IRS defined pro-rate method to only the forecast entries to this balance. Support for this calculation is included in Exhibit___(BCH-1), Schedule 14, ADIT Pro-Rate. The IRS requirements for this adjustment are described in more detail in the Direct Testimony of Ms. Wold.

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

- Schedule 10, page 1, row 46, column 11,
- Schedule 11, page 1, row 40, column 17,
- Schedule 12, page 1, row 38, column 5,
- Volume 4, Section VIII Adjustments, Tab A28.

14) Cash Working Capital

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

A. As discussed earlier in Section IV.D, Other Rate Base, the Company has incorporated a secondary calculation to apply the various revenue lead days and expense lag days to the various income statement components to result in the appropriate cash working capital rate base adjustment. The adjustment impacts the test year revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 46, column 12,
- Schedule 11, page 1, row 40, column 18,
- Schedule 12, page 1, row 39, column 5,
- Volume 4, Section VIII Adjustments, Tab A29.

15) Change in Cost of Capital

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

A. The cost of capital adjustment is the effect of the changes in the overall cost of capital between the cost of capital (also referred to as the overall rate of return, or ROR) being requested in this case and the effective cost of capital authorized in Docket No. G002/GR-09-1153. Table 8 below provides the requested rate of return in this case, and the difference in the rate of return for the test year relative to the effective rate of return of 8.28 percent authorized in Docket No. G002/GR-09-1153.

Table 8

Proposed Rate of Return

	2022 Test Year
Proposed Rate of Return	7.46%
Decrease relative to 8.28%	0.82%

On Schedule 11, Income Statement Adjustment Schedule, the revenue deficiencies for the base data and all other adjustments are calculated at the 8.28 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 occur during the duration of the rate case do not affect the revenue requirements for each adjustment. The adjustment reflects both the change in the stated ROE of 10.09 percent in our last rate case to 10.50 percent (for final rates only) as well as the changes in short-term and long-term debt.

The reduction in our overall rate of return as compared to our 2010 test year equates to a reduction of 82 basis points or $6.7 million in revenue requirements. The impact of these adjustments on the test year revenue requirements is shown on:

- Schedule 11, page 1, row 40, column 19,
- Volume 4, Section VIII Adjustments, Tab A31.

16) Net Operating Loss

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

A. The Company is not currently in a net operating loss position; therefore no adjustment is necessary.

F. Rebuttal Adjustments

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION?

A. In this section, I provide details related to an adjustment we identified during our final quality assurance reviews performed just prior to this filing. This adjustment reflects a small change we believe necessary that we identified after we finalized our cost of service and rate design and that we were not able to incorporate due to timing constraints. Consistent with prior rate cases, we propose to incorporate this adjustment into interim rates as applicable, and to update the Test Year Forecast revenue requirement for final rates when we file Rebuttal Testimony.

17) Distributed Intelligence

Q. PLEASE DESCRIBE THE REBUTTAL ADJUSTMENT RELATED TO DISTRIBUTED INTELLIGENCE

A. As discussed by Ms. Wold, we determined that the Company's budget includes a portion of the Distributed Intelligence (DI) project that was originally assigned to common utility plant, meaning that a portion was allocated to the Minnesota gas jurisdiction. However, this project will serve only the electric utility. This adjustment of approximately $30,000 revenue requirement removes the DI costs from interim rates in this gas proceeding. We will further update our final rate request in Rebuttal Testimony.

VIII. COSTS RECOVERED IN RIDERS AND TRACKER

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

A. In this section, I present our proposed treatment of costs recovered in riders during the test year, including riders that we propose to continue to use and costs we propose to move to base rates. I also propose tracker treatment for costs associated with removing the customer-paid individual transaction fee for each credit card payment of their gas service bill and including credit card transaction costs in our overall cost of service. I provide detailed information supporting the adjustments to the test year that I presented in Section VII of my testimony.

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

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

A. Our proposed total revenue requirement in 2022, including our proposed increase in base rates, is approximately $209.40 million as reflected in Table 9 below.

Table 9

Total Cost Recovery Including Riders (000s)

Recovery Method	2022 Test Year
Present Revenues	$541,016
Cumulative Rate Increase	35,629
Proposed Revenues	576,645
Less: Rider Revenue included in present revenue	
GUIC Rider	27,482
CIP Rider	18,668
SEP Gas Rider	1,037
PGA Rider	320,055
Total Rider Revenue included in present revenue	367,242
Net Base Rate Revenue Requirement	**$209,403**

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

A. GUIC Rider

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

A. The project costs and revenues associated with the projects remaining in the GUIC Rider have been removed from our 2022 test year. A review is also done for each GUIC filing to ensure that no costs included in base rates are included in the GUIC filing. I provide information related to the 2022 test year adjustment that ensures no double recovery of these costs in Section VII.D. Rider Removals, GUIC Rider (adjustment 12).

Q. PLEASE DESCRIBE HOW YOU ARE PROPOSING TO MOVE PROJECTS TO BASE RATES AT THE CONCLUSION OF THIS RATE CASE.

A. As noted above, we propose to move projects from the GUIC rider to base rates at the conclusion of this case because it reduces the Interim Rate increase and clarifies that there is no potential for double recovery of costs. Coincident with the implementation of final rates in this rate case, the project costs will be removed from the GUIC rider 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 electric Environmental Improvement Rider (EIR) and the Nobles Wind, Grand Meadow Wind and Wind2Battery projects recovered through the RES Rider into base rates when final electric rates were implemented in that case.

More specifically, the GUIC rider will be updated to exclude costs for these projects for the remaining months of the year following implementation. The GUIC present revenues will be excluded from the 2022 test year and final rates will be designed to recover the final revenue requirement approved by the Commission, including the final revenue requirement for these projects. The interim rate refund will not be affected for these projects, as any over/under recovery during the interim rate period related to these projects will remain in the GUIC rider.

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

A. We propose to submit a GUIC Rider compliance report with Final Rate compliance. This report will clearly identify the revenue requirements removed from the GUIC Rider, the revenue recovered from customers for the projects moving to base rates during the interim rate period, and the development of the revised GUIC Rider adjustment factors.[4] The Company anticipates this process will be similar to the process used to move recovery of CIP costs from the CIP Rider to base rates.

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

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

Q. HOW WILL YOU ENSURE NO DOUBLE RECOVERY OF THESE PROJECT COSTS OCCURS DURING THE INTERIM RATE PERIOD?

A. We are proposing to continue recovery of these projects through the GUIC Rider during the interim period and to move these projects into base rates at the end of this case. The 2022 test year also includes the project costs in the test year cost of service as well as the project revenues in present revenue.

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[4] Due to the current implementation pattern for GUIC Rider adjustment factors, the calculation of this rate will be reflected in the Final Rate compliance filing but will be implemented consistent with the timing of the applicable GUIC adjustment factors.

Thus, an interim rate adjustment is necessary to ensure no double recovery of these costs during the interim rate period. Accordingly, our 2022 interim rate request includes an adjustment to remove the projects identified to roll into base rates and the present revenue from the development of interim rates.

Q. PLEASE PROVIDE ADDITIONAL DETAIL RELATED TO THE INTERIM RATE ADJUSTMENT FOR THE GUIC RIDER COSTS.

A. The Interim Rate Adjustment removes the project costs and present revenue included in the 2022 test year from the interim cost of service. This adjustment decreases the interim cost of service rate base by $207.2 million and present revenue by $27.5 million. Additional detail on this adjustment can be found in Volume 1, Notice of Change in Rates and Interim Rate Petition, Interim Rate Supporting Schedules and Workpapers.

B. SEP Rider

Q. WHAT COSTS ARE RECOVERED THROUGH THE SEP RIDER?

A. There are two types of natural gas-related expenses currently authorized for recovery in the SEP Rider per Minnesota statutes and Commission Orders: Assessment for Department Regional and National Duties (ADRND) and Cast Iron Pipe Replacement Project expenses (also referred to as Greenhouse Gas Infrastructure costs).

Q. HOW IS THE SEP RIDER TREATED IN THE TEST YEAR?

A. The Company proposes to roll all SEP rider projects into base rates as part of this rate case; therefore, all costs and present revenues are included in the 2022 test year.

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

A. During the interim rate period, the Company proposes to roll all projects into interim rates and discontinue use of the SEP rider. An adjustment is made to interim rates to remove $1.0 million in present SEP rider revenue which increases the interim rate request.

C. CIP Rider

Q. WHAT COSTS ARE RECOVERED THROUGH THE CIP RIDER?

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

Q. HOW IS THE CIP RIDER TREATED IN THE TEST YEAR?

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

D. Purchased Gas Adjustment (PGA)

Q. HOW IS THE PGA TREATED IN THE TEST YEAR?

A. Purchased gas costs are recovered from customers through the PGA. Both revenue and purchased gas expenses recovered through the PGA are included in the test year, and the total amount of each is equal. Any true-up of the revenues and costs during the test year will occur in the PGA and, therefore, there will be no need to address a change in revenue requirement in the final compliance filing.

E. Credit Card Fee Tracker

Q. WHAT IS THE COMPANY PROPOSING WITH RESPECT TO CREDIT CARD FEES?

A. Mr. Cardenas describes that the Company historically passed through credit card company fees to individual customers who use credit cards to pay their utility bills, as a per-transaction fee. However, customers have come to expect the ability to use credit cards to pay a variety of bills without being separately charged a fee for each payment. As Mr. Cardenas explains, we are proposing to include credit card fees in our base rate structure so that the fees are part of overall O&M rather than passed to customers as individual transaction fees. Because this program would be new for the Company, we are proposing to establish a baseline amount of credit card fees in base rates and track actual costs above or below that baseline for recovery or return to customers in a future rate case.

Q. WHY DOES THE COMPANY BELIEVE A TRACKER WOULD BE APPROPRIATE?

A. Given that this is a new means of managing credit card costs for NSPM, prior to program implementation, it is difficult to predict how it will affect customer behavior and the extent to which it will change Company credit card payment costs. While Mr. Cardenas supports the Company's initial estimates, a tracker would mitigate any risk of over- or under-collection so that only actual costs are ultimately recovered through rates.

Q. PLEASE DESCRIBE THE COMPANY'S TRACKER PROPOSAL IN MORE DETAIL.

A. As Mr. Cardenas explains in his Direct Testimony, the Company currently estimates annual total gas credit card fees of approximately $1.7 million, once customers are no longer charged individually for each transaction. We propose to establish this amount in our test year revenue requirement and track actual annual fees above and/or below this baseline between initiating the program (approximately January 1, 2024) and our next Minnesota gas rate case. We would then address the net regulatory asset or liability in our next rate case.

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 gas 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.

F. MGP Expense Tracker

Q. WHAT IS THE COMPANY PROPOSING WITH RESPECT TO MGP EXPENSES?

A. Ms. Zich describes manufactured gas plant (MGP) investigation and clean-up costs historically incurred by the Company and ongoing. In Docket No. G002/M-17-894, the Company requested deferral treatment for these variable and important costs and the Commission denied that request but stated the Company could propose recovery in its next rate case. As Ms. Zich explains, we are proposing to include MGP expenses in our base rate structure. Because these costs are variable from year-to-year, but ongoing and important, the Company is proposing to establish a baseline amount of MGP expense in base rates and track actual costs above or below that baseline for recovery or return to customers in a future rate case.

Q. WHY DOES THE COMPANY BELIEVE A TRACKER WOULD BE APPROPRIATE?

A. Given that the MGP expenses incurred are subject to site specific conditions, redevelopment activities by third parties, and changing environmental standards, it is difficult to predict the actual costs that will be incurred in future years at any one particular site. On average, over time, and across multiple projects, however, the Company has incurred, and will continue to incur, MGP investigation and clean-up costs. While Ms. Zich supports the Company's initial estimates, a tracker would mitigate any risk of over- or under-collection so that only actual costs are ultimately recovered through rates.

Q. PLEASE DESCRIBE THE COMPANY'S TRACKER PROPOSAL IN MORE DETAIL.

A. As Ms. Zich explains in her Direct Testimony, the Company established an estimate of $1 million of MGP expense in the 2022 test year based on historical data, recognizing that emerging science, new facts, potential insurance recoveries, and ongoing work on these sites creates significant uncertainty. We propose to establish this amount in our test year revenue requirement and track actual costs above and/or below this baseline annually starting January 1, 2022 until our next Minnesota gas rate case. If insurance recoveries are obtained, they will be applied to the regulatory asset to offset the costs incurred. We would then address the net regulatory asset or liability in our next rate case.

Q. WHY IS THIS TRACKER PROPOSAL REASONABLE?

A. As stated above, the actual amount of our ongoing MGP expenses incurred are subject to multiple factors that are difficult to predict. The tracker will ensure the Company does not over- or under-collect MGP expenses in the test year in relation to actual annual expenses.

IX. COMPLIANCE WITH PRIOR COMMISSION ORDERS

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

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

A. Compliance Requirements

1) Relief and Recovery Docket Tracking

Q. WHAT IS THE COMPLIANCE REQUIREMENT FROM THE COMPANY'S COVID-19 RELIEF & RECOVERY DOCKET?

A. In response to the Commission's request for projects that could assist with Minnesota's economic recovery from the COVID-19 pandemic,[5] the Company proposed to accelerate certain Distribution, Transmission, and Gas Operations projects and sought a Commission determination that acceleration of these projects was appropriate.[6] The Commission concluded that the proposed projects had the potential to be consistent with the Commission's request for proposals that could assist with recovery from the COVID-19 pandemic; that the Commission would determine project prudence in future rate cases; and that the acceleration of these projects "would not be the sole basis for any disapproval in the future."[7] Further, the Commission required the Company to "track investment spending for the acceleration of the projects separately from base rates, with clear delineation between portions that are included in base rates and those that are incremental to base rates."[8]

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[5] *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. E,G-999/CI-20-492 (June 17, 2020).

[6] *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).

[7] *Id.* at Order Point 1.

[8] *Id.* at Order Point. 2.

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

A. Yes. As discussed by Ms. Zich, the Company is requesting approval of certain Isolation Valve and Copper Riser Replacement projects as part of its test year in this case. In total, the 2021 forecast includes $2.9 million, and the 2022 test year includes $0.3 million for these projects. Additional support for the projects can be found in Ms. Zich's Direct Testimony.

Q. HAS THE COMPANY INCLUDED THESE PROJECTS IN ITS COST RECOVERY REQUESTS IN ANY OTHER DOCKET BEFORE THE COMMISSION?

A. No. These programs were specifically tracked for Relief and Recovery purposes and are included in the cost of service in this rate case on that basis.

Q. HAS THE COMPANY IDENTIFIED SPECIFIC COSTS ASSOCIATED WITH ACCELERATING THESE PROJECTS?

A. Because these are each projects that the Company otherwise intended to complete, and simply have been accelerated as discussed by Ms. Zich, the costs simply show up in the Company's rate request earlier than they otherwise might have. Therefore, while the Company will recover the costs of these projects earlier than it otherwise might have, customers are receiving the benefits earlier, including efforts to make jobs available and advance the work of Minnesota's Energy Utility Diversity Group as described by Ms. Zich.

Q. IS THE COMPANY PROVIDING THE COMMISSION WITH INFORMATION REGARDING THESE PROJECTS IN ANY OTHER DOCKETS?

A. Yes. Consistent with the Commission's March 12 and March 16, 2021 Orders in Docket No. E,G-999/CI-20-492, the Company continues to track its spending related to these COVID-19 Relief & Recovery projects and the Company has been providing this information to the Commission as part of its quarterly compliance filings in that docket.[9]

2) Incentive Compensation Refunds

Q. WHAT ARE THE REQUIREMENTS RELATED TO INCENTIVE COMPENSATION REFUNDS?

A. In Docket No. G002/GR-92-1186, the Commission required Xcel Energy to refund all incentive compensation payments included in the test year revenue requirement, but not paid.

Q. HOW IS COMPLIANCE WITH THESE REQUIREMENTS REFLECTED IN THE COMPANY'S RATE CASE REQUEST?

A. For 2020 (paid in March 2021), incentive plan payouts were above the level in base rates and no refund was required to gas customers, as reported in our annual incentive compensation compliance filing in Docket No. E,G002/M-21-369 on June 1, 2021. Our 2010 test year included the budgeted incentive compensation costs accrued in 2010 and payable in March 2011, after excluding certain costs (*e.g.*, AIP over base salary cap).

The 2022 test year includes the budgeted incentive compensation costs accrued in 2022 and payable in March 2023, after excluding certain costs (*e.g.*, AIP over base salary cap).

[9] *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).

Q. DOES THE COMPANY PROPOSE ANY CHANGES TO THE AIP INCENTIVE REFUND PROGRAM?

A. Yes. Once rates have been established at the conclusion of this rate proceeding, we propose to eliminate the yearly AIP compliance filing requirement and any associated reports regarding the AIP. The Company is also proposing the elimination of the AIP refund. Ms. Lowenthal discusses this proposal in her Direct Testimony.

3) Rate Case Expense

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REQUIREMENTS RELATED TO RATE CASE EXPENSES.

A. In Docket No. G-002/GR-09-1153, the Company was directed to defer rate case expense recovery after the four-year amortization period in that rate case. The Company has complied with this requirement as discussed in Section VII.C.11, Annual Adjustments to the Test Year.

4) Recurring Compliance Reporting Requirements

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

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

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REQUIREMENTS RELATED TO HOMESMART.

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

b) Tax Benefit Transfer Leases

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REQUIREMENTS RELATED TO TAX BENEFIT TRANSFER LEASES.

A. In Docket No. G002/GR-97-1606, the Company was directed to treat Tax Benefit Transfer (TBT) leases consistent with prior Commission approved methodology. There are no TBTs included in the test year. Since this provision has not been triggered in many years, the Company proposes to discontinue this reporting in future rate cases.

X. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. I recommend that the Commission determine an overall 2022 retail revenue requirement of $576.65 million and 2022 revenue deficiency of $35.63 million for the Company's Minnesota jurisdictional gas operation, determined by the cost of service for the 2022 test year. I also recommend a revenue deficiency for the test year as follows:

Table 10

2022 Revenue Request

Minnesota Jurisdictional ($s in millions)

Test Year	2020
Net Deficiency	$35.63
Average % increase, incremental *	6.6%

Lastly, I also recommend the Commission grant a 2022 interim rate increase of $24.9 million for the Company's Minnesota jurisdictional operation.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Resume of Benjamin C. Halama

Manager of Revenue Analysis
Revenue Requirements–North

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

Current Responsibilities

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

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

SUMMARY OF REVENUE REQUIREMENTS
($000's)

Line	Description	Adjusted Proposed Test Year 2022
1	Average Rate Base	$934,448
2	Operating Income (Before AFUDC)	$40,629
3	Allowance for Funds Used During Construction	$3,693
4	Total Available for Return (Line 2 + Line 3 + Rounding)	$44,321
5	Overall Rate of Return (Line 4 / Line 1)	4.74%
6	Required Rate of Return	7.46%
7	Operating Income Requirement (Line 1 x Line 6)	$69,710
8	Income Deficiency (Line 7 - Line 4)	$25,388
9	Gross Revenue Conversion Factor	1.40335
10	Revenue Deficiency (Line 8 x Line 9)	$35,629
11	Retail Related Revenue Under Present Rates	$541,016
12	Percentage Increase Needed in Overall Revenue (Line 10 / Line 11)	6.59%

COST OF SERVICE SUMMARY for 2022 TEST YEAR ($000's)

Line No.		Minnesota Gas Jurisdiction 2022 Test Year
1	**Composite Income Tax Rate**	
2	State Tax Rate	9.80%
3	Federal Statuatory Tax Rate	21.00%
4	Federal Effective Tax Rate	18.94%
5	**Composite Tax Rate**	**28.74%**
6	Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.403351
7		
8	**Weighted Cost of Capital**	
9	Active Rates and Ratios Version	Proposed
10	Cost of Short Term Debt	0.94%
11	Cost of Long Term Debt	4.13%
12	Cost of Common Equity	10.50%
13	Ratio of Short Term Debt	0.61%
14	Ratio of Long Term Debt	46.89%
15	Ratio of Common Equity	52.50%
16	Weighted Cost of STD	0.01%
17	Weighted Cost of LTD	1.94%
18	Weighted Cost of Debt	1.95%
19	Weighted Cost of Equity	5.51%
20	**Required Rate of Return**	**7.46%**
21		
22	**Rate Base**	
23	Plant Investment	1,788,364
24	Depreciation Reserve	691,832
25	Net Utility Plant	1,096,532
26	CWIP	27,627
27		
28	Accumulated Deferred Taxes	202,226
29	DTA - NOL Average Balance	
30	DTA - Federal Tax Credit Average Balance	-
31	Total Accum Deferred Taxes	202,226
32		
33	Cash Working Capital	(13,747)
34	Materials and Supplies	1,249
35	Fuel Inventory	14,823
36	Non-plant Assets and Liabilities	7,928
37	Customer Advances	(117)
38	Customer Deposits	(289)
39	Prepaids and Other	2,485
40	Regulatory Amortizations	183
41	Total Other Rate Base Items	12,515
42		
43	**Total Rate Base**	**934,448**
44		
45	**Operating Revenues**	
46	Retail	541,016
47	Interdepartmental	
48	Other Operating Rev - Non-Retail	4,908
49	**Total Operating Revenues**	**545,924**
50		

COST OF SERVICE SUMMARY for 2022 TEST YEAR ($000's)

Line No.		Minnesota Gas Jurisdiction 2022 Test Year
51	**Expenses**	
52	Operating Expenses:	
53	Purchased Gas	320,055
54	Gas Production & Storage	5,659
55	Gas Transmission	2,419
56	Gas Distribution	39,105
57	Customer Accounting	14,038
58	Customer Service & Information	19,873
59	Sales, Econ Dvlp & Other	34
60	Administrative & General	21,869
61	**Total Operating Expenses**	**423,052**
62		
63	Depreciation	53,130
64	Amortization	167
65		
66	**Taxes:**	
67	Property Taxes	19,358
68	ITC Amortization	(107)
69	Deferred Taxes	2,957
70	Deferred Taxes - NOL	
71	Less State Tax Credits deferred	
72	Less Federal Tax Credits deferred	
73	Deferred Income Tax & ITC	2,851
74	Payroll & Other Taxes	2,847
75	**Total Taxes Other Than Income**	**25,056**
76		
77	**Income Before Taxes**	
78	Total Operating Revenues	545,924
79	less: Total Operating Expenses	423,052
80	Book Depreciation	53,130
81	Amortization	167
82	Taxes Other than Income	25,056
83	**Total Before Tax Book Income**	44,519
84		
85	**Tax Additions**	
86	Book Depreciation	53,130
87	Deferred Income Taxes and ITC	2,851
88	Nuclear Fuel Burn (ex. D&D)	
89	Nuclear Outage Accounting	
90	Avoided Tax Interest	704
91	Other Book Additions	-
92	**Total Tax Additions**	56,684
93		
94	**Tax Deductions**	
95	Total Rate Base	934,448
96	Weighted Cost of Debt	1.95%
97	Debt Interest Expense	18,222
98	Nuclear Outage Accounting	
99	Tax Depreciation and Removals	70,340
100	NOL Utilized / (Generated)	
101	Other Tax / Book Timing Differences	(894)
102	**Total Tax Deductions**	**87,667**
103		

COST OF SERVICE SUMMARY for 2022 TEST YEAR ($000's)

Line No.		Minnesota Gas Jurisdiction 2022 Test Year
104	**State Taxes**	
105	State Taxable Income	13,537
106	State Income Tax Rate	9.80%
107	State Taxes before Credits	1,327
108	Less State Tax Credits applied	-
109	**Total State Income Taxes**	1,327
110		
111	**Federal Taxes**	
112	Federal Sec 199 Production Deduction	
113	Federal Taxable Income	12,210
114	Federal Income Tax Rate	21.00%
115	Federal Tax before Credits	2,564
116	Less Federal Tax Credits	-
117	**Total Federal Income Taxes**	2,564
118		
119	**Total Taxes**	
120	Total Taxes Other than Income	25,056
121	Total Federal and State Income Taxes	3,891
122	**Total Taxes**	28,946
123		
124	**Total Operating Revenues**	**545,924**
125	**Total Expenses**	**505,296**
126		
127	AFDC Debt	1,080
128	AFDC Equity	2,613
129		
130	**Net Income**	**44,321**
131		
132	**Rate of Return (ROR)**	
133	Total Operating Income	44,321
134	Total Rate Base	934,448
135	**ROR (Operating Income / Rate Base)**	4.74%
136		
137	**Return on Equity (ROE)**	
138	Net Operating Income	44,321
139	Debt Interest (Rate Base * Weighted Cost of Debt)	(18,222)
140	Earnings Available for Common	26,100
141	Equity Rate Base (Rate Base * Equity Ratio)	490,585
142	**ROE (earnings for Common / Equity)**	**5.32%**
143		
144	**Revenue Deficiency**	
145	Required Operating Income (Rate Base * Required Return)	69,710
146	Net Operating Income	44,321
147	**Operating Income Deficiency**	25,388
148		
149	Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.403351
150	**Revenue Deficiency (Income Deficiency * Conversion Factor)**	**35,629**
151		
152	**Total Revenue Requirements**	
153	Total Retail Revenues	541,016
154	Revenue Deficiency	35,629
155	Total Revenue Requirements	576,645

Line No.	Summary Cash Working Capital		Lead/Lag Days	Minnesota Gas Jurisdiction 2022 Test Year Dollars	Dollar x Days
1	**Fuel Expenses**				
2	Coal and Rail Transport		-	-	-
3	Gas for Generation		39.09	320,055	12,510,966
4	Oil		-		
5	Nuclear and EOL				
6	**Subtotal Fuel Expenses**			**320,055**	**12,510,966**
7	**Purchased Power**				
8	Purchases				
9	Interchange				
10	**SubTotal Purchased Power**				
11	**Labor and Related**				
12	Regular Payroll		11.89	36,336	432,039
13	Incentive		246.18	363	89,400
14	Pension and Benefits		37.25	6,730	250,676
15	**SubTotal Labor and Related**			**43,429**	**772,115**
16	All Other Operating Expenses		22.74	60,418	1,373,898
17	Property taxes		357.82	19,350	6,923,859
18	Employer's Payroll Taxes		31.64	2,847	90,088
19	Gross Earnings Tax		56.57	15,445	873,695
20	Federal Income Tax		37.00	2,551	94,380
21	State Income Tax		29.50	1,320	38,932
22	State Sales Tax Customer Billings		35.07	24,111	845,587
23	**Total Expenses**	A		**489,526**	**23,523,519**
24	Net Annual Expense			48	64,448
25	**Revenues**				
26	Retail Revenue		38.09	546,104	20,801,105
27	Late Payment		-	1,481	-
28	Interdepartmental		-		
29	Misc Services		38.09	2,074	79,002
30	Rentals		(50.12)	1,346	(67,481)
31	Interchange		-		
32	Retail Rev Lag Days		38.09	7	257
33	MISO		-		
34	Wholesale Lag Days		-		
35	**Total Revenues**	B		**551,012**	**20,812,883**
36	Net Annual Amount			38	57,022
37	Expense/Revenue Factor	C = A/B			88.9%
38	Allocated Revenue Amount	D = B * C			50,701
39	**Net Cash Working Capital**	E = D - A			**(13,747)**

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 gas distribution system.

NSPM Gas
Northern States Power Company, including the portion allocated or direct assigned to the gas 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 Gas Jurisdiction
Amounts direct assigned or allocated to the gas utility and to the State of Minnesota.

Notes:

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

Order	**Topic**	**Witness**	**Financial Source**
1	Policy	Chamberlain	NSPM Gas
2	Net-Zero Vision for Natural Gas	Lyng	N/A
3	Revenue Requirements	Halama	State of MN Gas Jurisdiction
4	Capital Structure	Johnson	NSPM (Total Company)
5	Return on Equity	D'Ascendis	State of MN Gas Jurisdiction
6	Budgeting	Ostrom	NSPM Gas
7	Sales Forecast	Marks	NSPM Gas
8	Gas Operations	Zich	NSPM Gas
9	Gas Operations - Peaking Plants	Palkovich	NSPM Gas
10	Service Policy & Extensions	Hults	NSPM Gas
12	Business Systems	Remington	NSPM (Total Company)
12	Customer Care/Bad Debt	Cardenas	NSPM Gas
13	Cost Allocations	Baumgarten	NSPM Gas
14	Property Tax	Arend	NSPM (Total Company)
15	Employee Expenses	Husen	NSPM (Total Company)
16	Depreciation	Wold	State of MN Gas Jurisdiction
17	Pension and Benefits Expense	Schrubbe	State of MN Gas Jurisdiction
18	Pension Investments	Inglis	N/A
19	Compensation and Benefits	Lowenthal	Xcel Energy, NSPM (Total Company), and NSPM Gas
20	CCOSS	Barthol	State of MN Gas Jurisdiction
21	Rate Design/Decoupling	Terwilliger	State of MN Gas Jurisdiction

Northern States Power Company
State of Minnesota Gas Utility

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

	Increase (Decrease) 2022 TY to 2010 TY
Capital Related	
Distribution	33.1
General and Intangible	9.1
Gas Production and Storage	4.9
Transmission	2.3
Other Rate Base	(1.6)
Cost of Capital	2.8
TOTAL Capital Related	50.5
Amortizations	(0.1)
Taxes	
Taxes - Other	8.3
Property Tax	6.6
Payroll Tax	0.9
TOTAL Taxes	15.8
Operating Expense	
Gas Production and Storage	1.4
Transmission	1.2
Distribution	15.0
Customer Accounting / Info / Service	(1.4)
A&G	5.7
TOTAL O&M	21.9
Other Margin Impacts	
Sales Change	(23.7)
GUIC & SEP Rider Revenue	(28.5)
Other Revenue	(0.2)
TOTAL Other Margin Impacts	(52.4)
TOTAL Net Incremental Deficiency	**35.6**

COMPARISON OF DETAILED RATE BASE COMPONENTS
Test Year Ending December 31, 2022
($000's)

Line No.	Description	General Rate Case Filing Docket No. G002/GR-09-1153 & E,G999/CI-17-895* (A)	General Rate Case Filing Docket No. G002/GR-21-678 Test Year (B)	Change (C) = (B) - (A)
	Gas Plant as Booked			
1	Gas Manufactured Plant	$15,537	$50,807	$35,270
2	Gas Storage	29,959	66,050	36,091
3	Gas Transmission	63,410	121,439	58,029
4	Gas Distribution	735,901	1,364,436	628,535
5	General	33,543	94,564	61,021
6	Common	62,221	91,069	28,848
7	TOTAL Utility Plant in Service	$940,571	$1,788,364	$847,794
8				
9	Reserve for Depreciation			
10	Gas Manufactured Plant	$11,943	$10,510	($1,433)
11	Gas Storage	22,257	43,072	20,815
12	Gas Transmission	24,423	28,585	4,162
13	Gas Distribution	332,091	523,033	190,942
14	General	12,567	44,102	31,535
15	Common	41,876	42,529	653
16	TOTAL Reserve for Depreciation	$445,158	$691,832	$246,674
17				
18	Net Utility Plant in Service			
19	Gas Manufactured Plant	$3,594	$40,297	$36,703
20	Gas Storage	7,702	22,978	15,276
21	Gas Transmission	38,987	92,853	53,866
22	Gas Distribution	403,810	841,402	437,593
23	General	20,976	50,462	29,486
24	Common	20,345	48,539	28,194
25	Net Utility Plant in Service	$495,413	$1,096,532	$601,119
26				
27	Utility Plant Held for Future Use	$0	$0	$0
28				
29	Construction Work in Progress	$4,228	$27,627	$23,399
30				
31	Less: Accumulated Deferred Income Taxes	$86,047	$202,226	$116,179
32				
33	Other Rate Base Items:			
34	Cash Working Capital	($3,935)	($13,747)	($9,812)
35	Materials and Supplies	1,037	1,249	212
36	Fuel Inventory	41,844	14,823	(27,021)
37	Non-Plant Assets & Liabilities	(9,640)	7,928	17,568
38	Customer Advances	0	(117)	(117)
39	Interest on Customer Deposits	0	(289)	(289)
40	Prepaids and Other	4,895	2,485	(2,410)
41	Regulatory Amortizations	0	183	183
42	Total Other Rate Base Items	$34,201	$12,515	($21,686)
43				
44	Total Average Rate Base	$447,794	$934,448	$486,653

*Prior case reflects the impact of TCJA on the prior rate case

STATEMENT OF OPERATING INCOME
2010 Final Compliance versus 2022 Test Year
($000s)

Line No.	Description	General Rate Case Filing Docket No. G002/GR-09-1153 & E,G999/CI-17-895* (A)	General Rate Case Filing Docket No. G002/GR-21-678 Test Year (B)	Change (C) = (B) - (A)
	Operating Revenues			
1	Retail	$582,828	$541,016	($41,812)
3	Interdepartmental	0	0	0
4	Other Operating	4,693	4,908	215
5	Gross Earnings Tax	0	0	0
6	**Total Operating Revenues**	$587,521	$545,924	($41,597)
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	$429,081	$320,055	($109,026)
8	Power Production	4,305	5,659	1,354
9	Transmission	1,261	2,419	1,158
10	Distribution	24,062	39,105	15,043
11	Customer Accounting	14,657	14,038	(619)
12	Customer Service & Information	5,611	19,873	14,262
13	Sales, Econ Dvlp & Other	31	34	3
14	Administrative & General	16,148	21,869	5,721
15	Total Operating Expenses	$495,156	$423,052	($72,104)
16	Depreciation	$32,754	$53,130	$20,376
17	Amortizations	$300	$167	($133)
	Taxes:			
18	Property	$12,798	$19,358	$6,560
19	Gross Earnings	0	0	0
20	Deferred Income Tax & ITC	(1,229)	2,851	4,080
21	Federal & State Income Tax	9,117	3,891	(5,226)
22	Payroll & Other	1,946	2,847	901
23	Total Taxes	$22,632	$28,946	$6,315
24	**Total Expenses**	$550,842	$505,296	($45,546)
25	AFUDC	$398	$3,693	$3,295
26	**Total Operating Income**	$37,077	$44,321	$7,244

Note: Revenues reflect calendar month sales.

*Prior case reflects the impact of TCJA on the prior rate case

Northern States Power Company

Docket No. G002/GR-21-678
Exhibit___(BCH-1), Schedule 9
Page 1 of 3

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

		Proposed Test Year 2022					
		Total Gas Utility			Minnesota Gas Jurisdiction *		
Line No.	Description	Unadjusted** (A)	Adjustments (B)	Adjusted (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	Adjusted (F) (D) + (E)
	Gas Plant as Booked						
1	Production	$58,137	$0	$58,137	$50,807	$0	$50,807
2	Storage	75,579	0	75,579	66,050	0	66,050
3	Transmission	130,929	(5,592)	125,337	127,031	(5,592)	121,439
4	Distribution	1,579,301	(36,940)	1,542,362	1,401,375	(36,940)	1,364,436
5	General	106,672	0	106,672	94,564	0	94,564
6	Common	102,729	0	102,729	91,069	0	91,069
7	TOTAL Utility Plant in Service	$2,053,347	($42,532)	$2,010,815	$1,830,896	($42,532)	$1,788,364
	Reserve for Depreciation						
8	Production	$16,072	($4,046)	$12,026	$14,046	($3,536)	$10,510
9	Storage	53,939	(4,653)	49,286	47,138	(4,067)	43,072
10	Transmission	30,402	(142)	30,260	28,727	(142)	28,585
11	Distribution	582,166	713	582,879	522,321	713	523,033
12	General	49,453	296	49,749	43,840	262	44,102
13	Common	47,949	26	47,975	42,506	23	42,529
14	TOTAL Reserve for Depreciation	$779,981	($7,806)	$772,175	$698,578	($6,746)	$691,832
	Net Utility Plant in Service						
15	Production	$42,065	$4,046	$46,111	$36,761	$3,536	$40,297
16	Storage	21,640	4,653	26,293	18,912	4,067	22,978
17	Transmission	100,527	(5,451)	95,077	98,304	(5,451)	92,853
18	Distribution	997,135	(37,652)	959,483	879,055	(37,652)	841,402
19	General	57,219	(296)	56,923	50,724	(262)	50,462
20	Common	54,780	(26)	54,754	48,562	(23)	48,539
21	Net Utility Plant in Service	$1,273,366	($34,725)	$1,238,640	$1,132,318	($35,786)	$1,096,532
22	Utility Plant Held for Future Use	$0	$0	$0	$0	$0	$0
23	Construction Work in Progress	$29,429	$0	$29,429	$27,627	$0	$27,627
24	Less: Accumulated Deferred Income	$221,501	$1,223	$222,724	$201,280	$947	$202,226
25	Cash Working Capital	($15,069)	$427	($14,642)	($14,119)	$372	($13,747)
	Other Rate Base Items:						
26	Materials and Supplies	$1,409	$0	$1,409	$1,249	$0	$1,249
27	Gas In Storage	16,855	0	16,855	14,823	0	14,823
28	Non-Plant Assets & Liabilities	8,942	0	8,942	7,928	0	7,928
29	Customer Advances	(1,463)	0	(1,463)	(117)	0	(117)
30	Customer Deposits	(326)	0	(326)	(289)	0	(289)
31	Prepayments	2,816	0	2,816	2,485	0	2,485
32	Regulatory Amortizations	0	206	206	0	183	183
33	Total Other Rate Base Items	$28,233	$206	$28,439	$26,079	$183	$26,262
34	Total Average Rate Base	$1,094,458	($35,315)	$1,059,143	$970,625	($36,178)	$934,448

(*) See Volume 3, Rate Base Section, Schedule E for allocation factors.
(**) Unadjusted at Proposed Capital Structure

COMPARISON OF DETAILED RATE BASE COMPONENTS
Test Year Ending December 31, 2022
($000's)

		Proposed Test Year 2022					
		Total Gas Utility			Minnesota Gas Jurisdiction *		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Adjusted (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	Adjusted (F) (D) + (E)
	Construction Work in Progress						
1	Production	$384	($0)	$384	$336	($0)	$336
2	Storage	2,894	0	2,894	2,529	0	2,529
3	Transmission	1,066	0	1,066	1,066	0	1,066
4	Distribution	18,279	0	18,279	17,664	0	17,664
5	General	2,357	0	2,357	2,088	0	2,088
6	Common	4,449	0	4,449	3,944	0	3,944
7	TOTAL Construction Work In Progress	$29,429	($0)	$29,429	$27,627	($0)	$27,627

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

Northern States Power Company

Docket No. G002/GR-21-678
Exhibit___(BCH-1), Schedule 9

COMPARISON OF DETAILED RATE BASE COMPONENTS
Test Year Ending December 31, 2022
($000's)

		Proposed Test Year 2022					
		Total Gas Utility			Minnesota Gas Jurisdiction *		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Adjusted (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	Adjusted (F) (D) + (E)
	Accumulated Deferred Income Taxes						
1	Production	$494	$1,109	$1,603	$432	$968	$1,401
2	Storage	(682)	1,287	604	(596)	1,124	528
3	Transmission	21,403	(457)	20,946	20,687	(459)	20,228
4	Distribution	182,353	(592)	181,761	164,962	(576)	164,386
5	General	9,819	(108)	9,712	8,706	(96)	8,609
6	Common	7,403	(16)	7,388	6,563	(14)	6,549
7	Non-Plant Related	711	0	711	524	0	524
8	TOTAL Accum Deferred Income Taxes	$221,501	$1,223	$222,724	$201,280	$947	$202,226

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

($000s)

		Bridge - Unadjusted				Adjustment				Amortization	Rider Removals	Secondary Calculations		
		Unadjusted w/o NOL & 199 at Last Authorized	ADIT Prorate for IRS	Cash Working Capital	Total Unadjusted at Last Authorized	Black Dog Pipeline	Depreciation Study	New Business CIAC	Remaining Life Study: NSPM	Income Tax Tracker	GUIC Rider Removal	ADIT Prorate for IRS	Cash Working Capital	Total
	Workpaper Reference					WP A-15	WP A-18 - WP A-19	WP A-23	WP A-24	WP A-25	WP A-27	WP A-28	WP A-29	
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
(1)														
(2)	Plant as booked													
(3)	Gas Manufactured Plant	50,807			50,807									50,807
(4)	Gas Storage	66,050			66,050									66,050
(5)	Gas Transmission	127,031			127,031	(4,632)					(960)			121,439
(6)	Gas Distribution	1,401,375			1,401,375			(75)			(36,865)			1,364,436
(7)	General	94,564			94,564									94,564
(8)	Common	91,069			91,069									91,069
(9)	Total Utility Plant in Service	1,830,896			1,830,896	(4,632)		(75)			(37,825)			1,788,364
(10)														
(11)	Reserve for Depreciation													
(12)	Gas Manufactured Plant	14,046			14,046		(1,217)		(2,319)					10,510
(13)	Gas Storage	47,138			47,138		78		(4,145)					43,072
(14)	Gas Transmission	28,727			28,727	(269)	24				104			28,585
(15)	Gas Distribution	522,321			522,321		157	(2)			558			523,033
(16)	General	43,840			43,840		262							44,102
(17)	Common	42,506			42,506		23							42,529
(18)	Total Reserve for Depreciation	698,578			698,578	(269)	(672)	(2)	(6,464)		662			691,832
(19)														
(20)	Net Utility Plant													
(21)	Gas Manufactured Plant	36,761			36,761		1,217		2,319					40,297
(22)	Gas Storage	18,912			18,912		(78)		4,145					22,978
(23)	Gas Transmission	98,304			98,304	(4,363)	(24)				(1,064)			92,853
(24)	Gas Distribution	879,055			879,055		(157)	(72)			(37,423)			841,402
(25)	General	50,724			50,724		(262)							50,462
(26)	Common	48,562			48,562		(23)							48,539
(27)	Net Utility Plant in Service	1,132,318			1,132,318	(4,363)	672	(72)	6,464		(38,487)			1,096,532
(28)														
(29)	Utility Plant Held for Future Use													
(30)														
(31)	Construction Work in Progress	27,627			27,627									27,627
(32)														
(33)	Less: Accumulated Deferred Income Taxes	201,277	3		201,280	(371)	188	(0)	1,810		(590)	(90)		202,226
(34)														
(35)	Other Rate Base Items													
(36)	Cash Working Capital			(14,145)	(14,145)								398	(13,747)
(37)	Materials and Supplies	1,249			1,249									1,249
(38)	Fuel Inventory	14,823			14,823									14,823
(39)	Non Plant Assets and Liabilities	7,928			7,928									7,928
(40)	Customer Advances	(117)			(117)									(117)
(41)	Customer Deposits	(289)			(289)									(289)
(42)	Prepayments	2,485			2,485									2,485
(43)	Regulatory Amortizations									183				183
(44)	Total Other Rate Base	26,079		(14,145)	11,934					183			398	12,515
(45)														
(46)	Total Average Rate Base	984,747	(3)	(14,145)	970,599	(3,991)	484	(72)	4,654	183	(37,897)	90	398	934,448

($000s)

		Bridge - Unadjusted				Precedential	Adjustment								Amortization	
		Unadjusted w/o NOL & 199 at Last Authorized	ADIT Prorate for IRS	Cash Working Capital	Total Unadjusted at Last Authorized	Precedential Adjustments	Black Dog Pipeline	CIP Approved Program Levels	Credit Card AutoPay	Depreciation Study	Incentive Compensation	New Area Surcharge	New Business CIAC	Remaining Life Study: NSPM	Income Tax Tracker	Rate Case Expenses
	Workpaper Reference					WP A-1 - WP A-14	WP A-15	WP A-16	WP A-17	WP A-18 - WP A-19	WP A-20 - WP-A21	WP A-22	WP A-23	WP A-24	WP A-25	WP A-26
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
(1)																
(2)	Operating Revenues															
(3)	Retail Revenue	549,291			549,291			(3,187)								
(4)	Other Operating	3,237			3,237							1,671				
(5)	Total Revenue	552,528			552,528			(3,187)				1,671				
(6)																
(7)	Expenses															
(8)	Operating Expenses															
(9)	Purchased Gas	320,055			320,055											
(10)	Gas Production and Storage	5,659			5,659											
(11)	Gas Transmission	2,419			2,419											
(12)	Gas Distribution	39,955			39,955											
(13)	Customer Accounting	12,346			12,346				1,692							
(14)	Customer Service and Information	23,060			23,060			(3,187)								
(15)	Sales, Econ Dev, & Other	27			27	7										
(16)	Administrative and General	23,010			23,010	(1,514)					373					
(17)	Total Operating Expenses	426,532			426,532	(1,507)		(3,187)	1,692		373					
(18)																
(19)	Depreciation	66,813			66,813		(67)			(343)			(5)	(12,928)		
(20)	Amortization														73	94
(21)																
(22)	Taxes															
(23)	Property	19,350			19,350											
(24)	Deferred Income Tax and ITC	303			303		(70)			96			(0)	3,620		
(25)	Federal and State Income Tax	521	0	121	642	434	125		(486)	(4)	(107)	480	2	(40)	(23)	(27)
(26)	Payroll and Other	2,850			2,850	(3)										
(27)	Total Taxes	23,023	0	121	23,144	431	55		(486)	92	(107)	480	2	3,580	(23)	(27)
(28)																
(29)	Total Expenses	516,368	0	121	516,489	(1,076)	(12)	(3,187)	1,206	(251)	266	480	(3)	(9,348)	51	67
(30)																
(31)	Allowance for Funds Used During Construction	3,693			3,693											
(32)																
(33)	Net Income	39,853	(0)	(121)	39,732	1,076	12		(1,206)	251	(266)	1,191	3	9,348	(51)	(67)
(34)																
(35)	Calculation of Revenue Requirements															
(36)	Rate Base	984,747	(3)	(14,145)	970,599		(3,991)			484			(72)	4,654	183	
(37)	Required Operating Income	81,439	(0)	(1,170)	80,269		(330)			40			(6)	385	15	
(38)	Operating Income	39,853	(0)	(121)	39,732	1,076	12		(1,206)	251	(266)	1,191	3	9,348	(51)	(67)
(39)	Income Deficiency	41,585	(0)	(1,049)	40,536	(1,076)	(342)		1,206	(211)	266	(1,191)	(9)	(8,963)	66	67
(40)	**Revenue Deficiency**	**58,359**	**(0)**	**(1,472)**	**56,887**	**(1,510)**	**(480)**		**1,692**	**(296)**	**373**	**(1,671)**	**(12)**	**(12,578)**	**92**	**94**
(41)																
(42)	Calculation of Income Taxes															
(43)	Operating Revenue	552,528			552,528			(3,187)				1,671				
(44)	-Operating Expense	426,532			426,532	(1,507)		(3,187)	1,692		373					
(45)	-Amortization														73	94
(46)	-Taxes Other then Income	22,503			22,503	(3)	(70)			96			(0)	3,620		
(47)	Operating Income Before Adjs	103,494			103,494	1,510	70		(1,692)	(96)	(373)	1,671	0	(3,620)	(73)	(94)
(48)	Additions to Income	2,440			2,440		(70)			96			(0)	3,620		
(49)	Deductions from Income	74,777			74,777		(316)						(6)			
(50)	Debt Synchonization	29,345	(0)	(422)	28,924		(119)			14			(2)	139	5	
(51)	State Taxable Income	1,811	0	422	2,233	1,510	435		(1,692)	(14)	(373)	1,671	8	(139)	(79)	(94)
(52)	State Income Tax Before Credits	177	0	41	219	148	43		(166)	(1)	(37)	164	1	(14)	(8)	(9)
(53)	State Tax Credits															
(54)	Federal Tax Deductions															
(55)	Federal Taxable Income	1,633	0	380	2,014	1,362	393		(1,526)	(13)	(336)	1,507	7	(125)	(71)	(85)
(56)	Federal Income Tax Before Credits	343	0	80	423	286	82		(320)	(3)	(71)	317	1	(26)	(15)	(18)
(57)	Federal Tax Credits															
(58)	Total Income Taxes	521	0	121	642	434	125		(486)	(4)	(107)	480	2	(40)	(23)	(27)

($000s)

		Rider Removals	Secondary Calculations			
		GUIC Rider Removal	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Total
	Workpaper Reference	WP A-27	WP A-28	WP A-29	WP A-31	
		(16)	(17)	(18)	(19)	(20)
(1)						
(2)	Operating Revenues					
(3)	Retail Revenue	(5,088)				541,016
(4)	Other Operating					4,908
(5)	Total Revenue	(5,088)				545,924
(6)						
(7)	Expenses					
(8)	Operating Expenses					
(9)	Purchased Gas					320,055
(10)	Gas Production and Storage					5,659
(11)	Gas Transmission					2,419
(12)	Gas Distribution	(850)				39,105
(13)	Customer Accounting					14,038
(14)	Customer Service and Information					19,873
(15)	Sales, Econ Dev, & Other					34
(16)	Administrative and General					21,869
(17)	Total Operating Expenses	(850)				423,052
(18)						
(19)	Depreciation	(341)				53,130
(20)	Amortization					167
(21)						
(22)	Taxes					
(23)	Property	8				19,358
(24)	Deferred Income Tax and ITC	(1,097)				2,851
(25)	Federal and State Income Tax	132	(1)	(3)	2,766	3,891
(26)	Payroll and Other					2,847
(27)	Total Taxes	(958)	(1)	(3)	2,766	28,946
(28)						
(29)	Total Expenses	(2,149)	(1)	(3)	2,766	505,296
(30)						
(31)	Allowance for Funds Used During Construction					3,693
(32)						
(33)	Net Income	(2,939)	1	3	(2,766)	44,321
(34)						
(35)	Calculation of Revenue Requirements					
(36)	Rate Base	(37,897)	90	398		934,448
(37)	Required Operating Income	(3,134)	7	33	(7,569)	69,710
(38)	Operating Income	(2,939)	1	3	(2,766)	44,321
(39)	Income Deficiency	(195)	7	30	(4,803)	25,388
(40)	**Revenue Deficiency**	**(273)**	**9**	**41**	**(6,740)**	**35,629**
(41)						
(42)	Calculation of Income Taxes					
(43)	Operating Revenue	(5,088)				545,924
(44)	-Operating Expense	(850)				423,052
(45)	-Amortization					167
(46)	-Taxes Other then Income	(1,090)				25,056
(47)	Operating Income Before Adjs	(3,148)				97,649
(48)	Additions to Income	(2,531)				3,555
(49)	Deductions from Income	(5,010)				69,445
(50)	Debt Synchonization	(1,129)	3	12	(9,625)	18,222
(51)	State Taxable Income	460	(3)	(12)	9,625	13,537
(52)	State Income Tax Before Credits	45	(0)	(1)	943	1,327
(53)	State Tax Credits					
(54)	Federal Tax Deductions					
(55)	Federal Taxable Income	415	(2)	(11)	8,682	12,210
(56)	Federal Income Tax Before Credits	87	(1)	(2)	1,823	2,564
(57)	Federal Tax Credits					
(58)	Total Income Taxes	132	(1)	(3)	2,766	3,891

2022 Test Year
(000s)

(1) Line No.	(2) Record Category	(3) Report Label	(4) Record Type	(5) MN Gas 2022 Test Year	(6) Workpaper Reference
1	Unadjusted	Unadjusted	**Total Unadjusted**	**51,256**	
2					
3	Precedential	Precedential Adjustments	NSPM-Advertising (Trad)	(227)	WP-A1
4	Precedential	Precedential Adjustments	NSPM-Assn Dues (Trad)	(11)	WP-A2
5	Precedential	Precedential Adjustments	NSPM-Aviation	(144)	WP-A3
6	Precedential	Precedential Adjustments	NSPM-Chamber of Commerce Dues	11	WP-A4
7	Precedential	Precedential Adjustments	NSPM-Customer Deposits - A&G Expense (Trad)	2	WP-A5
8	Precedential	Precedential Adjustments	NSPM-Donations (Trad)	40	WP-A6
9	Precedential	Precedential Adjustments	NSPM-Econ Dev Donations (Trad)	7	WP-A7
10	Precedential	Precedential Adjustments	NSPM-Econ Develop (Trad)	(16)	WP-A8
11	Precedential	Precedential Adjustments	NSPM-Employee Expenses	(181)	WP-A9
12	Precedential	Precedential Adjustments	NSPM-Foundation Admin	(11)	WP-A10
13	Precedential	Precedential Adjustments	NSPM-Incentive Pay	(114)	WP-A11
14	Precedential	Precedential Adjustments	NSPM-Incentive Pay_Remove Long Term	(764)	WP-A12
15	Precedential	Precedential Adjustments	NSPM-Pension Non-Qual Restoration Removal	(80)	WP-A13
16	Precedential	Precedential Adjustments	NSPM-Pension Non-Qual SERP Removal	(23)	WP-A14
17	Precedential		**Sub-Total Precedential**	**(1,510)**	
18					
19	Adjustment	Black Dog Pipeline	NSPM-Black Dog Pipeline	(451)	WP-A15
20	Adjustment	CIP Approved Program Levels	NSPM-CIP Approved Program Levels	-	WP-A16
21	Adjustment	Credit Card AutoPay	NSPM-Credit Card Auto Pay Fees	1,692	WP-A17
22	Adjustment	Depreciation Study	NSPM-MN Gas Depreciation Study TD&G	910	WP-A18
23	Adjustment	Depreciation Study	NSPM-MN Gas Remaining Life	(1,210)	WP-A19
24	Adjustment	Incentive Compensation	NSPM-Incentive Pay_Environmental LTI	134	WP-A20
25	Adjustment	Incentive Compensation	NSPM-Incentive Pay_Time Based LTI	239	WP-A21
26	Adjustment	New Area Surcharge	NSPM-NAS and ES Exclusion	(1,671)	WP-A22
27	Adjustment	New Business CIAC	NSPM-New Bus CIAC 2021	(12)	WP-A23
28	Adjustment	Remaining Life Study: NSPM	NSPM-MN Gas Remaining Life Extension	(12,611)	WP-A24
29	Adjustment		**Sub-Total Adjustment**	**(12,979)**	
30					
31	Amortization	Income Tax Tracker	NSPM-Income Tax Tracker	91	WP-A25
32	Amortization	Rate Case Expenses	NSPM-Amortization Rate Case Expense	94	WP-A26
33	Amortization		**Sub-Total Amortization**	**185**	
34					
35	Rider Removals	Rider: GUIC	NSPM-Gas GUIC Rider RC Removal	(0)	WP-A27
36	Rider Removals		**Sub-Total Rider Removals**	**(0)**	
37					
38	Secondary Calculations	ADIT Prorate for IRS	NSPM-ADIT Prorate for IRS	8	WP-A28
39	Secondary Calculations	Cash Working Capital	NSPM-Cash Working Capital	(1,331)	WP-A29
40	Secondary Calculations		**Sub-Total Secondary Calculations**	**(1,323)**	
41					
42			Total Revenue Deficiency	35,629	

Note: Adjustment amounts in Schedule 12 reflect the revenue requirement calculated at the capital structure proposed in this rate case. See Workpaper A50 for the adjustment due to change in COC.

Northern States Power Company

Docket No. G002/GR-21-678
Exhibit____(BCH-1), Schedule 13

PRECEDENTIAL ADJUSTMENT DETAIL SCHEDULE
2022 Test Year
($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
		Precedential														
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	NSPM-Incentive Pay_Remove Long Term	NSPM-Pension Non-Qual Restoration Removal	NSPM-Pension Non-Qual SERP Removal	Total
1																
2	Operating Revenues															
3	Retail Revenue															
4	Other Operating															
5	Total Revenue															
6																
7	Expenses															
8	Operating Expenses															
9	Fuel & Purchased Energy															
10	Power Production															
11	Transmission															
12	Customer Accounting															
13	Customer Service and Information															
14	Sales, Econ Dev, & Other							7								7
15	Administrative and General	(227)	(11)	(142)	11	2	40		(16)	(181)	(10)	(114)	(764)	(80)	(23)	(1,514)
16	Total Operating Expenses	(227)	(11)	(142)	11	2	40	7	(16)	(181)	(10)	(114)	(764)	(80)	(23)	(1,507)
17																
18	Depreciation															
19	Amortization															
20																
21	Taxes															
22	Property															
23	Deferred Income Tax and ITC															
24	Federal and State Income Tax	65	3	41	(3)	(1)	(12)	(2)	5	52	3	33	220	23	6	434
25	Payroll and Other			(2)							(0)					(3)
26	Total Taxes	65	3	39	(3)	(1)	(12)	(2)	5	52	3	33	220	23	6	431
27																
28	Total Expenses	(162)	(8)	(103)	8	2	29	5	(11)	(129)	(8)	(81)	(545)	(57)	(16)	(1,076)
29																
30	Allowance for Funds Used During Constru															
31																
32	Net Income	162	8	103	(8)	(2)	(29)	(5)	11	129	8	81	545	57	16	1,076
33																
34	Calculation of Revenue Requirements															
35	Rate Base															
36	Required Operating Income															
37	Operating Income	162	8	103	(8)	(2)	(29)	(5)	11	129	8	81	545	57	16	1,076
38	Income Deficiency	(162)	(8)	(103)	8	2	29	5	(11)	(129)	(8)	(81)	(545)	(57)	(16)	(1,076)
39	**Revenue Deficiency**	**(227)**	**(11)**	**(144)**	**11**	**2**	**40**	**7**	**(16)**	**(181)**	**(11)**	**(114)**	**(764)**	**(80)**	**(23)**	**(1,510)**

Northern States Power Company
IRS Pro-Rate Method Accumulated Deferred Tax Adjustment
Including NOL Annual Deferred
Year Ending December 31, 2022

2022 Test Year

	Days to Prorate	Prorate Factor	MN Gas Jurisdiction Plant Deferred	MN Gas Jurisdiction Prorated Plant Deferred	MN Gas Jurisdiction NOL	MN Gas Jurisdiction Prorated NOL	Monthly Expense	Prorated Monthly Expense
Annual Deferred Tax Expense			2,375,194				2,375,194	
January	335	91.78%	197,933	181,664	-	-	197,933	181,664
February	307	84.11%	197,933	166,481	-	-	197,933	166,481
March	276	75.62%	197,933	149,670	-	-	197,933	149,670
April	246	67.40%	197,933	133,401	-	-	197,933	133,401
May	215	58.90%	197,933	116,591	-	-	197,933	116,591
June	185	50.68%	197,933	100,322	-	-	197,933	100,322
July	154	42.19%	197,933	83,511	-	-	197,933	83,511
August	123	33.70%	197,933	66,701	-	-	197,933	66,701
September	93	25.48%	197,933	50,432	-	-	197,933	50,432
October	62	16.99%	197,933	33,621	-	-	197,933	33,621
November	32	8.77%	197,933	17,353	-	-	197,933	17,353
December	1	0.27%	197,933	542	-	-	197,933	542
							Total	**1,100,290**

	(Increase)/ decrease to accumulated deferred taxes
Increase/(Decrease) in Rate Base	
Pro-Rate Method	(1,100,290)
BOY/EOY Average	(1,187,597)
Accumulated Deferred Taxes Adjustment	87,307
Capital Structure - Proposed	
Composite Tax Rate	28.74%
Weighted Cost of STD	0.01%
Weighted Cost of LTD	1.94%
Weighted Cost of Debt	1.95%
Weighted Cost of Equity	5.51%
Required Rate of Return	**7.46%**
Equity Return Tax RR	**2.22%**
RB Revenue Requirement Factor	9.6825%
Increase/(Decrease) in Revenue Requirement	
Annual Revenue Requirement Impact	8,454

Prorate Adjustment Factor

Days	Month	Prorated Days	Prorate Factor
31	Jan	335	0.917808
28	Feb	307	0.841096
31	Mar	276	0.756164
30	Apr	246	0.673973
31	May	215	0.589041
30	Jun	185	0.506849
31	Jul	154	0.421918
31	Aug	123	0.336986
30	Sep	93	0.254795
31	Oct	62	0.169863
30	Nov	32	0.087671
31	Dec	1	0.002740
365			

Prorate Factor Calculation

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