Direct Testimony and Schedules
Benjamin C. Halama

Before the South Dakota Public Utilities Commission
State of South Dakota

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

Docket No. EL22-_____
Exhibit___(BCH-1)

Overall Revenue Requirements
Rate Base
Income Statement

June 30, 2022

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

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

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

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

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

A. I provide testimony supporting the Company's financial data and its request for a general rate increase in the State of South Dakota retail electric jurisdiction. My testimony supports the income statement and rate base portions of the South Dakota cost of service. My testimony also addresses the South Dakota electric jurisdiction's operational need for new incremental revenues of $44.1 million or 17.9 percent, based on a pro forma year with known and measureable changes.

In addition, the Company proposes moving some cost recovery from two of its rate riders to base rates at the end of this proceeding. During the pro forma year, the Company recovered $33.8 million through the Infrastructure Rider consistent with the projects approved in Docket No. EL21-028. Consistent with the terms of the Settlement establishing the Infrastructure Rider and as described further in the Direct Testimony of Company Witness Ms. Farah Mandich, we propose to move this cost recovery to base rates. Second, during the pro forma year the Company recovered $7.9 million in revenues through the Transmission Cost Recovery (TCR) Rider consistent with the projects approved in Docket No. EL21-025. Pursuant to Commission policy, those projects will be rolled into base rates. Together, moving cost recovery from the Infrastructure Rider and the TCR Rider eliminates $41.7 million in Infrastructure Rider and TCR Rider revenues. Consequently, the revenue requirement satisfied by base rates increases by the same $41.7 million in order to replace the lost rider revenues.

To summarize, we propose an overall increase in base rates of $85.8 million, of which $44.1 million is the amount of the net incremental increase to our customers ($85.8 million total – $41.7 million rider transfer = $44.1 million incremental increase).

Q. WERE THE SCHEDULES PRESENTED WITH YOUR TESTIMONY PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were. Exhibit___(BCH-1), Schedule 2 provides an index of schedules presented with my testimony, including a description of the data and other filing sources.

Q. IN ADDITION TO THE SCHEDULES INCLUDED WITH THIS TESTIMONY, ARE THERE ADDITIONAL SCHEDULES YOU ARE SPONSORING?

A. Yes. I am sponsoring the following Statements and supporting Schedules, which are required by South Dakota Public Utilities Commission (Commission) Rules (Sections 20:10:13:51 *et seq.*). These Statements and Schedules are located in Volume 1 of the Application:

A. Balance sheet

B. Income statement

C. Earned surplus statements

D. Cost of plant

D-1. Detailed plant accounts

D-2. Plant addition and retirement for test period

D-3. Working papers showing plant accounts on average basis for test period

D-4. Plant account working papers for previous years

D-5. Working papers on capitalizing interest and other overheads during construction

D-6. Changes in intangible plant working papers

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D-8. Property records working papers

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E. Accumulated depreciation

E-1. Working papers on record changes to accumulated depreciation

E-2. Working papers on depreciation and amortization method

E-3. Working papers on allocation of overall accounts

F. Working capital

F-1. Monthly balances for materials, supplies, fuel stocks, and prepayments

- F-2. Monthly balances for two years immediately preceding pro forma year
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G. Cost of Capital, Long Term Debt and Stock
- G-1. Stock Dividends, Stock Splits, or Changes in Par or Stated Value
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I. Operating revenue

J. Depreciation expense
- J-1. Expense charged other than prescribed depreciation

K. Income taxes
- K-1. Working papers for federal income taxes
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- K-3. Working papers for consolidated federal income tax
- K-4. Working papers for an allowance for current tax greater than tax calculated at consolidated rate
- K-5. Working papers for claimed allowances for state income taxes

L. Other taxes
- L-1. Working papers for adjusted taxes

M. Overall cost of service

N. Allocated cost of service

P. Fuel cost adjustment factor

R. Purchases from affiliated companies

To the extent the Commission's rules require a discussion of the content of these required Schedules, a discussion is provided with the required Schedule. Company witness Mr. Allen Krug sponsors Statement Q, providing the required description of utility operations. Company witness Christopher J. Barthol provides the support for Statement O in his Direct Testimony.

Q. HAVE YOU RELIED ON INFORMATION PROVIDED BY OTHER WITNESSES IN PREPARING YOUR TESTIMONY AND SCHEDULES?

A. Yes. I relied on and incorporated information provided by other witnesses in this proceeding, as well as information provided by various Company business areas and subject matter experts. Where applicable, I indicate in my testimony where the pro forma year cost information is based on information provided by other witnesses.

II. CASE OVERVIEW

A. Test-Year Revenue Requirements and Deficiency

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

A. Yes, a Cost of Service Study was prepared under my direction. Exhibit___(BCH-1), Schedule 3 contains a copy of the jurisdictional cost of service study for the pro forma year.

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

A. The general form for calculating the revenue requirement and revenue deficiency is as follows:

	Item	2021 Pro Forma Amount ($000s)	Exhibit__ (BCH-1), Sch. 2 Reference
	Rate Base	$947,135	Page 1, Line 44
multiplied by	Cost of capital	7.65%	Page 1, Line 20
	Operating Income Requirement	**$72,456**	Page 4, Line 158
	Current Retail Revenue	$247,154	Page 2, Line 47 + Line 48
plus	Current Other Revenue	$63,895	Page 2, Line 49
equals	Current Total Revenue	$311,049	Page 2, Line 50
minus	Operating Expenses	$186,583	Page 2, Line 74
minus	Depreciation Expense	$75,079	Page 2, Line 76
minus	Amortization Expense	$3,490	Page 2, Line 77
minus	Taxes	$8,298	Page 3, Line 135
plus	AFUDC		Page 4, Line 140 + Line 141
equals	**Total Available for Return**	**$37,598**	Page 4, Line 143
	Operating Income Requirement	$72,456	Page 4, Line 158
minus	Total Available for Return	$37,598	Page 4, Line 143
equals	**Income Deficiency**	**$34,858**	Page 4, Line 160
multiplied by	Gross Revenue Conversion Factor	1.265823	Page 4, Line 162
equals	**Revenue Deficiency**	**$44,123**	Page 4, Line 163
plus	Current Retail Revenue	$247,154	Page 4, Line 166
equals	**Total Revenue Requirement**	**$291,277**	Page 4, Line 168

Q. WHAT IS THE AMOUNT OF THE JURISDICTIONAL REVENUE REQUIREMENT FOR SOUTH DAKOTA?

A. The jurisdictional total retail revenue requirement for South Dakota electric utility operations is $291.3 million, based on the adjusted rate base (this adjustment is discussed in further detail in Section IV) and net operating income for the pro forma year, as adjusted for known and measurable changes occurring in 2022 and 2023, as appropriate for final rates that will go into effect January 1, 2023. The jurisdictional retail revenue requirement is also based on the average 2021 capital structure, a weighted cost of long-term debt of 1.95 percent and a weighted cost of equity of 5.70 percent, based on a return on equity of 10.75 percent (ROE) as recommended by Company witness Mr. Dylan D'Ascendis in his Direct Testimony. This results in an overall rate of return (ROR) of 7.65 percent.

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

A. The incremental amount of the revenue deficiency (the amount by which the rates paid by our customers increases) for the pro forma year is $44.1 million or 17.9 percent. In addition, the Company currently recovers the costs of certain capital projects through the Infrastructure Rider and the TCR Rider, which will be recovered through an increase in base rates. The result is that the revenues collected under those two riders will decrease and will be replaced by an increase in base rates of $41.7 million, for a total increase in base rates of $85.8 million. As I will explain, the revenue deficiency includes $7.6 million in known and measureable capital project changes occurring in 2023 that, if the Commission prefers, could be recovered through the Infrastructure or TCR Riders.

Regardless of how these costs are treated in the rate case, the Company requests that the Infrastructure and TCR Riders continue into the future.

A summary of the revenue deficiency is shown in Exhibit___(BCH-1), Schedule 4, as a comparison of the jurisdictional revenue requirement amount for the pro forma year with the revenues under present rates as approved by the Commission in Docket No. EL14-058.[1] In order to earn an overall ROR of 7.65 percent, South Dakota retail electric rates need to be increased by this deficiency amount, as developed in Schedule 4.

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

A. The revenue deficiency amount represents an 17.9 percent increase in retail revenues compared to 2021 retail revenues at present rates as shown in Exhibit___(BCH-1), Schedule 4. When the revenue requirement is increased to incorporate the revenues from the TCR and Infrastructure Riders, the increase in base rates represents a 34.7 percent overall increase compared to 2021 retail revenues.

B. Case Drivers

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

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

[1] Present revenues as presented in the pro forma year are weather-normal base rate and fuel revenues plus the Transmission Cost Recovery (TCR), Demand Side Management (DSM), and Infrastructure Rider revenues.

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

A. Consistent with the analysis provided in prior rate cases, my explanation of the key deficiency cost drivers uses a comparison to the Commission-ordered results from our last electric rate case (Docket No. EL14-058), which used a 2013 pro forma year. I will refer to the comparison year as the 2013 pro forma year.

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

A. A summary of the cost elements to which the revenue deficiency can be attributed is provided in Exhibit___(BCH-1), Schedule 5. The major cost elements driving the revenue deficiency are identified in Table 1 below.

Table 1
Net Deficiency ($ in millions)

	Increase (Decrease) 2021 PF to 2013 PF
Capital and Capital Related	$94.3
Amortizations	3.3
Taxes	(10.2)
Operating Expense	8.3
Other Margin Impacts	(51.6)
Total Net Incremental Deficiency	$44.1

1) Capital Related Cost Drivers

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

A. Table 2 below compares the pro forma year forecast revenue requirements with the revenue requirements for the 2013 pro forma year, by category, for capital plant related costs as shown on Schedule 5.

Table 2
Capital and Capital Related Revenue Requirements Changes
($ in millions)

	Increase (Decrease) 2021 PF to 2013 PF
Wind	$19.1
Distribution	16.2
Cost of Capital	10.6
Nuclear	10.1
General and Intangible	10.0
Transmission	8.3
Nuclear Decommissioning Trust	7.0
Steam	4.5
All Other Production	4.5
DTA (Federal Credits & NOL)	2.3
Other Rate Base	1.7
TOTAL Capital and Capital Related	$94.3

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

A. The 2021 pro forma year revenue requirements include a $19.1 million increase related to our wind investments compared to the 2013 pro forma year. This increase is due to capital investments for the wind farms currently included in the Infrastructure Rider as well as the repower for the Grand Meadow Wind Farm. Company Witness Ms. Mandich discusses the Company's wind investments in her Direct Testimony.

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

A. The 2021 pro forma year revenue requirements include a $16.2 million increase due the Distribution business unit's capital investments in South Dakota compared to the 2013 pro forma year. This increase is due to capital investments relating to expansion of Distribution's asset health programs to address the portions of our system that are closest to our customers, such as pole and underground cable replacements. Distribution also manages work associated with our meter replacement initiative. Additional information regarding distribution's capital investments is provided in the Direct Testimony of Company witness Mr. Marty D. Mensen.

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

A. The 2021 pro forma year revenue requirements include a $10.6 million increase related to the Company's requested 10.75 percent ROE. Company witnesses Mr. Krug and Mr. D'Ascendis discuss the Company's recommended ROE.

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

A. The 2021 pro forma year revenue requirements include a $10.1 million increase due to Nuclear capital related investments when compared to the 2013 pro forma year. Company Witness Ms. Laurie J. Wold discusses the Company's key nuclear investments in her Direct Testimony.

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

A. The 2021 pro forma year revenue requirements include a $10.0 million increase to due to our investments in capital projects classified as General & Intangible compared to the 2013 pro forma year. This increase is mainly driven by investments in replacing aging technology, and in particular the Company's investments in its new General Ledger and Work and Asset Management programs. Ms. Wold discusses these key technology investments further in her Direct Testimony.

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

A. The 2021 pro forma year revenue requirements include an $8.3 million increase due to Transmission capital investments when compared to the 2013 pro forma year. The increase compared to the 2013 pro forma year is due mainly to the roll-in of transmission capital projects which were in service by the end of 2021, particularly the CapX2020, LaCrosse-Madison, and Huntley-Wilmarth projects from the TCR Rider. Ms. Wold discusses these transmission investments further in her Direct Testimony.

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

A. The 2021 pro forma year revenue requirements include a $7.0 million increase related to the Nuclear Decommissioning Trust (NDT) when compared to the 2013 pro forma year. Additional information regarding the NDT is provided by Ms. Wold.

Q. ARE THERE OTHER CAPITAL RELATED DRIVERS?

A. Yes, the 2021 pro forma year revenue requirements include a $9.0 million increase related to investments in steam and other production assets when compared to the 2013 pro forma year. This is due to investments in our generating assets to keep them in good working order to serve our customers. Additionally, in 2018, the Company also placed into service a new natural gas combustion turbine (Unit 6) at our existing Black Dog generating plant in Minnesota.

2) Amortizations

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN AMORTIZATIONS.

A. The 2021 pro forma year revenue requirements include a $3.3 million increase related to amortizations compared to the 2013 pro forma year. This increase is primarily due to a new amortization for the deferral of COVID-19 expenses, as authorized in Docket No. GE20-002, as well as an increase in Rate Case Expense amortization. The increase compared to the 2013 pro forma year is also due to a new amortization for the Net Operating Loss (NOL) Tax Reform Regulatory Amortization (discussed in adjustment 16 below).

3) Taxes

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN TAXES.

A. The 2021 pro forma year revenue requirements include a $10.2 million decrease due to taxes compared to the 2013 pro forma year. This decrease is driven by increased amounts of Production Tax Credits (PTCs) associated with new and existing wind farms being moved to base rate recovery in this case. The decrease compared to the 2013 pro forma year is also due to a decrease in the federal income tax rate from 35 percent to 21 percent effective January 1, 2018 with the enactment of the Tax Cuts and Jobs Act (TCJA). These items are partially offset by an increase in property taxes. The increase in PTCs is offset by the Fuel Cost Rider revenue included in the COSS as discussed in Section V.D below.

4) O&M

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

A. Table 3 below compares the 2021 pro forma year forecast revenue requirements with the revenue requirements for the 2013 pro forma year, by category, for operating expenses as shown on Schedule 5.

Table 3
O&M Cost Changes ($ in millions)

	Increase (Decrease) 2021 PF to 2013 PF
Transmission Interchange	$4.0
A&G	3.4
Transmission	3.4
Wind	2.7
Customer Accounting / Info / Service	0.1
Regional Markets	0.1
Purchased demand	0.0
All Other Production	(0.2)
Distribution	(0.8)
Nuclear	(1.9)
Steam	(2.5)
TOTAL O&M	$8.3

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

A. The 2021 pro forma year revenue requirements include a $4.0 million increase in transmission interchange operating expenses compared to the 2013 pro forma year. This increase is primarily due to the addition of the Wisconsin portion of the CAPX2020 La Crosse Project transmission line in 2014 and the

La Crosse - Madison 345 kV transmission line in December 2018, which is further described by Ms. Wold. I note that, because these capital projects are located in Wisconsin and owned by the Company's sister company, Northern States Power Company – Wisconsin, they are not included in rate base but are, rather, recovered through the Interchange Agreement and therefore recorded as an O&M expense.

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

A. The 2021 pro forma year revenue requirements include a $3.4 million increase in A&G expense compared to the 2013 pro forma year. The increase when compared to 2013 is primarily driven by the O&M associated with our investments in new information technology by our Business Systems business area. Specifically, we are incurring O&M expense increases for Application Development & Maintenance services, increased Software and Hardware licensing, and maintenance to support the capital assets built as a result of business demand. There is also an increase in employee benefits due to higher active healthcare costs.

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

A. The 2021 pro forma year revenue requirements include a $3.4 million increase in transmission operating expenses compared to the 2013 pro forma year. This cost increase is mainly due to increased Midcontinent Independent System Operator (MISO) transmission charges. These charges have increased due to investments made by the Company and other MISO transmission owners in the transmission grid.

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

A. The 2021 pro forma year revenue requirements include a net decrease of $1.8 million in nuclear, steam and wind operating expenses compared to the 2013 pro forma year. Offsetting this decrease is an increase in wind O&M associated with placing into service over 1,000 MW of new wind generating facilities. The wind O&M increase is fully offset when compared to the 2013 pro forma year by a reduction in nuclear outage costs and reduced overhaul and project investments as several coal units approach retirement. The wind O&M increase is further offset by rider revenue included in the COSS as discussed above.

5) Other Margin

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

A. Table 4 below compares the 2021 pro forma year forecast revenue requirements with the revenue requirements for the 2013 pro forma year, by category, for other margin as shown on Schedule 5.

Table 4
Net Deficiency ($ in millions)

	Increase (Decrease) 2021 PF to 2013 PF
Retail revenue – excluding fuel	($13.1)
Rider revenue	(41.7)
Other revenue	3.1
TOTAL Other Margin Impacts	($51.6)

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

A. From 2010 to 2021, South Dakota weather-normalized retail sales have increased by an average of 1.0 percent per year, which increases revenue earned by the Company under current rates. The increased revenue offsets part of the revenue requirement.

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

A. Yes. As noted above, for the rider eligible cost increases in capital and capital-related wind and transmission there is a corresponding increase in rider revenue included in the COSS. The increase is $41.7 million compared to the 2013 pro forma year.

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

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

III. SUPPORTING INFORMATION

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

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

A. Data Provided and Selection of Pro Forma Year

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

A. Following the rules of the Commission, financial data is provided for the calendar year 2021 (unadjusted test year) and the pro forma year that includes 2022 and 2023 known and measurable adjustments.

Financial data is first normalized to remove any unusual conditions in the actual year (*e.g.,* weather normalization) that should be adjusted for rate setting purposes. Next, the actual year is adjusted for regulatory treatment (*e.g.,* foundation administration expenses, incentive compensation, and advertising are removed). Then, the Company is proposing a number of adjustments in this rate case. A fourth set of adjustments is made to reflect standard amortizations. Finally, I make pro forma adjustments to reflect known and measurable changes occurring in 2022 and 2023 pursuant to Commission Rule 20:10:13:44, which permits a period of up to 24 months from the end of the historical test period to be considered in developing known and measurable adjustments. This ensures that final rates, which will become effective in 2023, more closely reflect the Company's revenues and expenses at the time the rates go into effect. The pro forma year Cost of Service Study is summarized in Exhibit___(BCH-1), Schedule 3.

I also provide in Exhibit___(BCH-1), Schedule 3 a cost of service study for the unadjusted 2021 year showing: the actual unadjusted average rate base; unadjusted operating income; overall rate of return; the calculation of required income; the income deficiency; and revenue requirements. Exhibit___(BCH-1), Schedules 6A and 6B are separate rate base and income statement bridge schedules that identify the adjustments described in my testimony to the unadjusted 2021 test year that create the pro forma year.

B. Jurisdictional Cost of Service Study

Q. PLEASE DESCRIBE THE COMPONENTS OF THE JURISDICTIONAL COST OF SERVICE STUDY FOR THE PRO FORMA YEAR.

A. The complete jurisdictional cost of service is included in Volume 3 (Workpapers) of the Company's filing. The jurisdictional cost of service includes: a revenue requirement, rate base, income statement, income tax, and a cash working capital computation.

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

A. The pro forma year jurisdictional cost of service summary is included in Exhibit___(BCH-1), Schedule 3. In order to facilitate a comparison to the unadjusted 2013 test year, we have also included the 2021 unadjusted test year jurisdictional cost of service summary in Exhibit___(BCH-1), Schedule 3.

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

A. Yes. The revenue conversion factor of 1.2658, using a South Dakota composite tax rate of 21 percent, is included in my exhibits on Exhibit___(BCH-1) Schedule 3, page 4, line 162.

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.

Q. DOES THE 2021 UNADJUSTED TEST YEAR PROVIDED IN YOUR SCHEDULES 6A AND 6B MATCH THE 2021 JURISDICTIONAL REPORT?

A. No, they are different. The rate case includes cash working capital in the rate base, while the jurisdictional report does not. Also, the 2021 Jurisdictional Report does not include the proposed adjustments presented to the pro forma year.

IV. RATE BASE

Q. IS THE PRO FORMA YEAR RATE BASE REASONABLE FOR PURPOSES OF DETERMINING FINAL RATES IN THIS PROCEEDING?

A. Yes. The pro forma year rate base was developed based on sound ratemaking principles, in a manner substantially similar to prior Company electric rate cases, with one adjustment to the methodology. As a result of the pro forma adjustments we made, the pro forma rate base appropriately represents costs and investments in place in 2023, the time period for which the rates will take effect.

Q. WHAT ADJUSTMENTS DID YOU MAKE TO THE PRO FORMA YEAR RATE BASE CALCULATION FOR THIS RATE CASE?

A. Overall the calculation of rate base is consistent with the Company's last electric rate case; however the Company is proposing a change in this rate case to reflect the plant related components of rate base using a year-end method as opposed to the 13-month average method used in the last rate case.

Q. WHAT IS THE IMPACT OF THIS PROPOSED CHANGE TO THE TOTAL RATE BASE IN THE PRO FORMA YEAR?

A. The total rate base in the pro forma year is $947.1 million. If the pro forma year were calculated using a 13-month average rate base the total rate base would be $939.3 million, a reduction of $7.8 million.

Q. HOW WAS THIS CHANGE IMPLEMENTED?

A. In order to implement this change, we used the December balances for all plant related (Plant Investment, Depreciation Reserve, Accumulated Deferred Taxes, Non-Plant Assets and Liabilities and Regulatory Amortizations) components of rate base and to calculate the pro forma rate base and revenue requirement.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF THIS PROPOSED CHANGE?

A. The total revenue requirement impact on this change and all associated changes is presented in Table 5 below.

Table 5
Revenue Requirement Impact of Year-End Rate Base
($ in millions)

Change in Required Operating Income	$0.60
Plus: Plant Annualization	2.96
Less: Revenue Year End	2.70
Plus: Secondary Calculations	0.04
Total Revenue Requirement Impact	$0.90

Q. WHY IS IT APPROPRIATE TO USE YEAR-END RATE BASE IN DETERMINING THE REVENUE REQUIREMENT FOR THIS RATE CASE?

A. As I noted earlier, the main goal when developing a cost of service study is to present costs that are representative of those expected to be incurred during the time rates from the rate case will be in effect. In other words, the costs included in the cost of service are representative of the cost of ongoing operations. This main goal then informs the rate base methodology that is used depending on whether the test year is a future test year or a historic test year.

In a future test year, the time period that is used to measure the cost to provide service coincides with the time the rates are in effect. In that case, it is appropriate to use an average rate base methodology because, as plant is added to the system, not all rate base will be in service during the rate year. As an example, consider a piece of equipment that is placed into service in the last month of a future test year, and the rate year coincides with the test year. It would be inappropriate to charge customers the full value of that piece of equipment since they only got the benefit of that equipment for one month. In the case of a historic test year, however, the test year and rate year do not coincide. The rate year occurs after the test year.

In a historical test year, the 13-month average methodology is less appropriate because regardless of what month in the test year plant is placed into service, customers are getting the full benefit of the plant during the rate year. Going back to the example above, customers are getting the full benefit of the equipment placed in service in the last month of the test year because it is in service for all months of the rate year. As such, the full cost of the equipment should be included in the rates charged during the rate year, which is what a year end rate base methodology accomplishes. Where an historic test year is used to set rates, a year-end rate base more closely reflects the rate base of the Company when rates are actually in effect. As discussed by several of the Company's witnesses, the Company is making significant investments related to its Electric business. By using year-end rate base for the historic test year, rates reflect the full cost of the assets for which customers are receiving the full benefit.

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 PRO FORMA YEAR RATE BASE.

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

- Net Utility Plant,
- Accumulated Deferred Income Taxes, and
- Other Rate Base.

Q. HOW DOES THE COMPANY CALCULATE RATE BASE?

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

Original Cost of Electric Plant in Service (Plant)
Less: Accumulated Depreciation Reserve (Reserve)

Less: Accumulated Provision for Deferred Taxes (net of accts 281-283 and 190) (ADIT)

Plus: Working Capital (Work Cap)

Plus: Other Rate Base

Equals: Total Rate Base

In this case, the calculation is as follows:

Plant	$1,885.7 million	(per BCH-1, Sch 2, Page 1, Line 23)
Reserve	($811.3 million)	(per BCH-1, Sch 2, Page 1, Line 24)
ADIT	($170.8 million)	(per BCH-1, Sch 2, Page 1, Line 32)
Working Capital	($1.4 million)	(per BCH-1, Sch 2, Page 1, Line 34)
Other Rate Base	$42.2 million	(per BCH-1, Sch 2, Page 1, Lines 35-41)
Total Rate Base	$947.1 million	(per BCH-1, Sch 2, Page 1, Line 44)

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

A. Exhibit___(BCH-1), Schedule 6A is a bridge schedule that shows the 2021 unadjusted test rate base, each proposed rate base adjustment, and the resulting proposed pro forma rate base.

Exhibit___(BCH-1), Schedule 7 provides a comparison of rate base components based on the final decision in the Company's last rate case filing (Docket No. EL14-058) to the pro forma year assuming final rates.

A. Net Utility Plant

Q. WHAT DOES NET UTILITY PLANT REPRESENT?

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

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

A. The net utility plant is included in rate base at depreciated original cost reflecting the year-end net plant balances. The year-end presentation is different from the net utility plant calculation in Docket No. EL14-058, as discussed above.

Q. WHAT HISTORICAL BASE DID XCEL ENERGY RELY ON AS A STARTING POINT TO DEVELOP THE NET PLANT BALANCE FOR THE PRO FORMA YEAR?

A. The historical base used was Xcel Energy's actual net investment (Plant in Service less Accumulated Depreciation) on the books and records of the Company as of December 31, 2021 plus the applicable adjustments, discussed in detail in Section VII below, to create the pro forma net plant balance.

B. Construction Work In Progress (CWIP)

Q. HAS CWIP BEEN INCLUDED IN THE PRO FORMA YEAR RATE BASE?

A. No. CWIP is not included in rate base, and there is no corresponding offset of Allowance for Funds Used During Construction (AFUDC) added to operating income.

C. Accumulated Deferred Income Taxes (ADIT)

Q. PLEASE DESCRIBE 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 is typically the extent to which accelerated tax depreciation exceeds book depreciation during the early years of an asset's service life. ADIT represents the cumulative net deferred tax amounts that have been allowed and recovered in rates in previous periods.

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

A. To the extent deferred income taxes have been allowed for recovery in rates, they represent a non-investor source of funds. Accordingly, the 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. HOW DID THE FEDERAL TAX CUT AND JOBS ACT (TCJA) AFFECT THE PROPOSED ADIT IN RATE BASE?

A. The Commission's adoption of the Settlement in Docket No. GE17-003 requires the Company to amortize its excess plant-related ADIT using the Average Rate Assumption Method, or ARAM, and amortize excess non-plant-related ADIT over three years. Consistent with this requirement, the Company is amortizing the excess plant-related ADIT using ARAM. The amortization of excess non-plant related ADIT concluded in 2020.

D. Other Rate Base

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

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

Q. PLEASE EXPLAIN WHAT WORKING CAPITAL REPRESENTS.

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

Q. HOW WERE PRO FORMA YEAR MATERIALS AND SUPPLIES AND FUEL INVENTORY REQUIREMENTS CALCULATED?

A. The Materials and Supplies and Fuel Inventory amounts shown on Exhibit___(BCH-1), Schedule 3, page 1, are based on the 13-month average ending balances for December 2020 through December 2021, respectively. The Materials and Supplies average balance included in the pro forma year rate base equals $12.0 million. The pro forma year average rate base amount for Fuel Inventory is $4.9 million.

Q. HOW WERE PRO FORMA YEAR NON-PLANT ASSETS AND LIABILITIES AND REGULATORY AMORTIZATIONS DETERMINED?

A. These balances as shown on Exhibit___(BCH-1), Schedule 3, page 1, represent the ending balance as of December 31, 2021. Any book/tax timing differences associated with these items have been reflected in the determination of current and deferred income tax provision and accumulated deferred tax balances previously discussed. The net assets increase pro forma year rate base by $22.1 million.

Q. HOW WERE PRO FORMA YEAR PREPAYMENTS AND OTHER WORKING CAPITAL ITEMS DETERMINED?

A. Items of Prepayments and Other Working Capital, such as customer advances and deposits, are based on the 13-month average ending balances for December 2020 through December 2021. The net impact of these various items increase pro forma year rate base by $2.9 million as shown on Exhibit___(BCH-1), Schedule 3, page 1.

Q. HOW WERE PRO FORMA 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 pro forma year revenues and expenses.

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 dates 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 SOUTH DAKOTA ELECTRIC RATE CASE (DOCKET NO. EL14-058)?

A. Yes. The average lag days are measured on the 12 months ended December 31, 2021. The results of the updated lead/lag study for electric operations were incorporated into the South Dakota jurisdiction cash working capital calculations provided in Volume 1, Required Statements, Statement N. The lead/lag study can be found in Volume 4 of our Application. Overall, the methodology used for calculating the lead/lag days is consistent with the Company's last electric rate case; however, the Company is proposing several changes in this rate case

Q. WHAT CHANGES IS THE COMPANY PROPOSING FOR THE LEAD/LAG STUDY IN THIS RATE CASE?

A. In the Commission-approved Settlement Stipulation in Docket EL14-058, the cash working capital calculation included vacation pay, deferred federal income taxes, interest on long term debt and a 20-day cap on revenue lag days. The Company does not believe these amounts are correctly included in the cash working capital calculation.

Vacation pay is a component of regular payroll and is paid out in the same manner therefore it is not appropriate to segregate it and assign payment lead days that are not consistent with regular payroll.

Interest on long term debt in the pro forma cost of service is an embedded calculation based on the 2021 debt rates and ratios and the pro forma rate base. The debt cost is based on the blended rates of the total debt portfolio. The result is a representative amount of interest expense (interest paid and accrued) for the pro forma year and therefore does not have any associated lead days to include in the cash working capital calculation.

Deferred federal income taxes are included in the total accumulated deferred taxes rate base balance as discussed in Section V. If deferred federal income taxes were included in the cash working capital calculation it would be duplicative.

Q. IS THE COMPANY PROPOSING A CHANGE TO THE LEAD/LAG STUDY RELATED TO THE 20-DAY CAP ON REVENUE LAG DAYS?

A. Yes. The Company is proposing to increase the cap to 30 days for revenue lag days. While it is appropriate to cap the revenue lag days when removing late payment revenue as discussed below in Section VII.B.7. The Company invoices customers on a monthly billing cycle and any overdue customers are charged late payments if payment is not received within 30 days; therefore it is more appropriate to use a revenue cap of 30 days for the cash working capital calculation.

Q. DID THE COMPANY CONSIDER ADDITIONAL METHODOLOGICAL CHANGES TO THE LEAD/LAG STUDY PREPARED FOR THIS RATE CASE?

A. Yes. In an effort to understand the most appropriate approach for South Dakota, the Company considered additional changes to the methodology for the lead/lag study based on methods used by utilities before FERC and other retail jurisdictions. For example, we identified that our current lead/lag study methodology does not account for the true cash flow nature of our property tax assessment and payments. Consequently, it may be appropriate to revise the lead/lag study methodology to better reflect the impacts of our property tax payments on cash working capital. Specifically, we pay taxes and we receive sufficient revenue from our customers in the same year, therefore there is no basis to maintain cash working capital with a material amount of lag days.

Ultimately, the Company did not adopt this new methodology but we are continuing to evaluate this for the future. Given that we did not make this change and only made the minor changes described above, our lead/lag study is generally consistent with the methodology used in prior South Dakota rate cases.

Q. WHAT IS THE PRO FORMA YEAR CASH WORKING CAPITAL AMOUNT?

A. The amount included in rate base is $1.4 million. The detailed components and calculations associated with this amount are provided in Volume 1, Required Statements, Statement N.

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

A. Yes. The pro forma year rate base was developed on sound ratemaking principles in a manner substantially similar to prior Company South Dakota electric rate cases.

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 pro forma year income statement.

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

A. Yes. The pro forma income statement for the Company's South Dakota jurisdiction electric operations was developed based on sound ratemaking principles in a manner similar to prior Company electric rate cases.

Q. PLEASE IDENTIFY THE MAJOR COMPONENTS OF THE INCOME STATEMENT.

A. The following are the major components of the income statement:

- Revenues,
- Operating and Maintenance Expenses,
- Depreciation Expense,
- Taxes, and
- Net Income.

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

A. Exhibit___(BCH-1), Schedule 8 provides a comparison of income statement components from the final decision in the Company's last rate case filing (Docket No. EL14-058) to the income statement components in the pro forma year assuming final rates.

Exhibit___(BCH-1), Schedule 6B is a bridge schedule that shows the 2021 unadjusted test year income statement, each proposed income statement adjustment, and the resulting proposed 2021 pro forma year income statement.

A. Revenues

Q. PLEASE DESCRIBE ANY CHANGES MADE TO THE PRESENT REVENUES IN THE PRO FORMA YEAR ENDED DECEMBER 31, 2021.

A. The present revenues used in the pro forma year were adjusted to remove the effect of weather, as discussed further by Mr. Nicholas N. Paluck. The present revenue based on actual 2021 data are affected by weather that is not necessarily representative of a typical or average weather pattern. Therefore, it is necessary to weather normalize the present revenue in the pro forma year.

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

A. Yes. The pro forma year includes items such as revenues from transmission-related assets and specific tariff charges including service activation fees, reconnection fees and others. One other source of revenues comes from billings to NSP Wisconsin (NSPW) under the Interchange Agreement, which I discuss in more detail below. Inclusion of these other operating revenues lower the income deficiency and ultimately the revenue deficiency.

B. Operating and Maintenance Expenses

Q. HOW DOES THE COMPANY CALCULATE OPERATING EXPENSES?

A. The Company's operating expenses can be expressed using the breakdown on pages 30-31 of the "Electric Utility Cost Allocation Manual" of NARUC as follows:

Operation and Maintenance Expense (including fuel) (Operating Expense)
Plus: Depreciation Expense (Depreciation)
Plus: Miscellaneous Amortization Expense (Amortization)
Plus: Taxes other than Income Taxes (Other Taxes)
Plus: Income Taxes (Income Tax)
Equals: Total Operating Expenses

In this case, the calculation is as follows (amounts are in millions):

Operating Expense	$186.6	(per BCH-1, Sch 2, Pg 2, Line 74)
Plus Depreciation	$ 75.1	(per BCH-1, Sch 2, Pg 2, Line 76)
Plus Amortization	$ 3.5	(per BCH-1, Sch 2, Pg 2, Line 77)
Plus Other Taxes	$17.4	(per BCH-1, Sch 2, Pg 2, Line 88)
Plus Income Tax	($9.1)	(per BCH-1, Sch 2, Pg 3, Line 134)
Total Operating Expense	$273.5	(per BCH-1, Sch 2, Pg 3, Line 138)

C. Depreciation Expense

Q. WHAT IS THE BASIS OF THE DEPRECIATION RATES AND EXPENSE USED IN THE PRO FORMA YEAR?

A. Depreciation expense for the pro forma year base data reflects the Company's depreciation rates approved in our last rate case (Docket EL14-058) and adjustments for Remaining Lives and Depreciation Rates for Transmission, Distribution and General Accounts. These adjustments are discussed in Section VII (adjustments 9 and 10). Ms. Wold discusses the Company's depreciation expense in her Direct Testimony.

D. Taxes

Q. WHAT TAX EXPENSES ARE INCLUDED IN THE PRO FORMA YEAR INCOME STATEMENT?

A. We have line items for Property; Income Taxes including Deferred Income Tax, Investment Tax Credits, Federal Income Tax; and Payroll Taxes. The Federal income taxes are calculated in Schedule 3, page 3 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, and 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 3, Section III Rate Base (Plant), Tab P6, Property Taxes 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 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 income taxes, which I will discuss in more detail below.

Q. DOES THE COST OF SERVICE REFLECT ANY POTENTIAL FEDERAL CORPORATE TAX RATE CHANGES FOR THE PRO FORMA 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 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?

A. At this time, it is not clear if or when federal tax rates may change, but the Company would likely need to work with the Commission to seek relief if such a change occurs. In the event of new tax legislation, it is also possible other South Dakota 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.

Q. PLEASE SUMMARIZE THE RATEMAKING TREATMENT OF NET OPERATING LOSSES (NOLS).

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

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

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

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

For the purpose of determining the NOL, these income tax calculations are done on an all-inclusive jurisdictional cost of service basis in which rider revenues and rider related investments are included with non-rider revenues and investments. This approach determines the extent to which the NSPM Electric Utility South Dakota retail jurisdiction is in a tax loss position or in a position to utilize deductions and credits carried forward from previous periods. This approach ensures that any reduction in revenue requirements resulting from the utilization of deductions or credits carried forward from prior periods is returned to customers as soon as it is available in the form of a reduction to base rates.

These balances related to unused credits and deductions are reported in the Company's June 1 Jurisdictional Annual Reports, including the most recent June 1, 2022 Jurisdictional Annual Report. By having these annual determinations made on an all-in basis, the jurisdictional cost of service study (JCOSS) includes actual data for both rider recovery and base rate recovery. Any change in rider recovery by the Commission will be incorporated in this process.

Q. DO THE DTAS AFFECT THE PRO FORMA YEAR REVENUE REQUIREMENTS?

A. Yes. The Company's pro forma year COSS includes a revenue requirement increase associated with NOLs and Production Tax Credits (PTCs) carried forward from prior periods to the pro forma year and generation of federal tax credits to be carried forward based on the Company's pro forma year COSS. An accounting for the balances carried forward to the pro forma year COSS, as well as the documented calculations supporting this revenue requirement increase, can be found in Volume 3, Section VIII Adjustments, Tab A33.

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

Q. WHAT ARE PTCS?

A. PTCs are per-kWh tax credits to income for electricity generated using qualified renewable energy resources.

Q. WHAT IS THE LEVEL OF PTCS INCLUDED IN THE FEDERAL INCOME TAX CALCULATION IN THE PRO FORMA YEAR?

A. As shown in Volume 3, Section III Rate Base (Plant), Tab P8, the pro forma year includes PTCs for the Company-owned wind farms generated in 2021. In the Settlement Stipulation approved by the Commission in Docket No. EL11-019, the Company and the South Dakota Commission Staff agreed that PTCs in that case and in the future would be passed through to customers through the Fuel Clause Rider. We have complied with that requirement, and the South Dakota jurisdiction total level of PTCs included in the unadjusted test year are offset by a reduction in Fuel Clause Rider revenue.

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

A. The Company continues to recommend that the Fuel Clause Rider serve as the mechanism for returning PTCs to customers. This approach meets our understanding of the current regulatory treatment for PTCs.

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

A. PTCs create a direct reduction (credit) to income tax expense causing a corresponding increase to operating income. Every dollar change in operating income needs a revenue conversion factor to be applied to determine the pre-tax revenue level necessary to achieve the operating income change. The revenue conversion factor calculation is included in Exhibit___(BCH-1) Schedule 3, page 4, line 162.

E. AFUDC

Q. WHAT IS AFUDC?

A. AFUDC is the cost of financing during the period a capital investment is constructed. Once an asset is placed in service, the total cost to construct, including accumulated AFUDC, is recovered through depreciation expense. As previously noted, CWIP is not included in rate base, therefore there is no corresponding offset of AFUDC added to operating income.

F. Interchange Agreement

Q. PLEASE DESCRIBE THE INTERCHANGE AGREEMENT WITH NSPW.

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

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

A. Under the Interchange Agreement, the Company and NSPW share annual system generation (production) and transmission costs. Under the Interchange Agreement formulas, approximately 16 percent of the costs of the Company system are allocated to NSPW, and approximately 84 percent of the NSPW system costs are allocated to the Company, because approximately 84 percent of the load on the integrated system is Company load and 16 percent is NSPW load. The exact allocation percentages are determined by the allocation factors updated and filed at FERC annually. The Interchange Agreement also provides for an allocation of certain non-retail revenues received by the Company and NSPW, such as revenues from off-system wholesale sales.

The 2021 unadjusted test year Interchange Revenue and Interchange Expenses have been calculated using 2021 Company and NSPW actual information. This is consistent with the treatment of Interchange Revenues and Interchange Expenses in the Company's 2013 unadjusted test year in Docket No. EL14-058.

Q. TO WHAT FERC ACCOUNTS ARE INTERCHANGE REVENUE AND INTERCHANGE EXPENSES RECORDED?

A. During 2021, Interchange Agreement revenues related to fixed and variable production as well as transmission system costs are recorded to FERC Account 456 – Other Electric Revenues. Interchange Agreement expense (billings from NSPW to the Company) are recorded to the following FERC Accounts:

Interchange Agreement Cost	FERC Account and Description
Fixed Production	557 – Other Power Supply Expenses-Other
Variable Production	557 – Other Power Supply Expenses-Other
Transmission	565 – Miscellaneous Transmission Expenses

Workpapers supporting the calculation for Interchange Agreement revenues (billings from the Company to NSPW) can be found in Volume 3, Section IV, Tab – R4, Interchange. Workpapers supporting the calculation of Interchange Agreement expenses (billings from NSPW to the Company) can be found in Volume 3, Section V, Tab – O2, Interchange. Copies of FERC filings and orders amending the Interchange Agreement since our last rate case are provided in Volume 4.

VI. UTILITY AND JURISDICTIONAL ALLOCATIONS

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

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

Cost allocation and assignment principles have not changed since our last South Dakota electric rate case. O&M cost assignments and allocations are also consistent with the Company's recent Minnesota electric rate case filed on October 25, 2021 with the Minnesota Public Utilities Commission (MPUC Docket No. E002/GR-21-630). Non-O&M costs include such items as book depreciation expense, deferred income taxes, and property taxes. All of the investments common to the electric and natural gas utilities, and their related costs (*e.g.*, software or other common investments and expenses), are evaluated as to whether the cost should be direct assigned to electric or natural gas, or allocated based on appropriate allocators such as: Customers, Customer Bills, Transportation Studies, or the three factor general allocator (the average of Revenue Ratio, Employee Ratio, and Asset Ratio).

Additional information regarding this process and the reason for selecting a particular allocator is also included in the Cost Assignment and Allocation Manual (CAAM), which is provided in Volume 4. There have not been any changes since the Company's last electric rate case that would significantly impact the percentage of costs that are assigned to South Dakota.

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

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

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

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

A. The Company's electric distribution plant investment amounts have been directly assigned, when possible, based upon the jurisdiction(s) served by each of the individual distribution facilities. Therefore, South Dakota distribution investments are generally assigned directly to South Dakota. However, if Distribution Investments include components that are common or general plant in nature they are allocated based on their functional class, consistent with the CAAM.

Q. PLEASE DESCRIBE ANY CHANGES MADE TO THE ALLOCATION FACTORS FOR USE IN THE PRO FORMA YEAR ENDED DECEMBER 31, 2021.

A. The jurisdictional allocation factors used in the pro forma year were adjusted to remove the effect of weather. The allocation factors are based on actual 2021 data (coincident peak demand, energy use), that are affected by weather that is not necessarily representative of a typical or average weather pattern. Therefore, it is necessary to weather normalize the coincident peak demand data prior to calculating the allocation factors. We made a similar weather normalizing adjustment to present revenues as discussed in Section V.A.

The allocation factors used in developing data in the unadjusted and pro forma year ending on December 31, 2021 may be found on Exhibit___(BCH-1), Schedule 9. Schedule 9 provides a side-by-side comparison of the allocation factors calculated two ways. The left columns present allocation factors using the 2021 unadjusted test year. The right columns are calculated based on normal weather for demand and energy.

VII. PRO FORMA ADJUSTMENTS

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

A. In this section of my testimony, I explain adjustments made to the 2021 actual year to make the resulting pro forma year appropriate for setting rates that will be finalized and applied to the service provided in 2023. 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 pro forma year.

Q. PLEASE DESCRIBE THE TYPES OF ADJUSTMENTS MADE TO THE PRO FORMA YEAR.

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

Q. PLEASE LIST ALL THE PRO FORMA ADJUSTMENTS.

A. A list of the pro forma year adjustments is shown on Exhibit___(BCH-1), Schedule 10. I will also discuss each adjustment later in my testimony. In addition, I provide bridge schedules (Exhibit___(BCH-1), Schedule 6A and Exhibit___(BCH-1), Schedule 6B that show all rate case adjustments, amortizations, rider removals, known and measureable adjustments, and secondary calculations. The following sections discuss each pro forma year adjustment in more detail.

A. Precedential Adjustments

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

A. Exhibit___(BCH-1), Schedule 10 provides a list of Precedential Adjustments and their associated revenue requirement impact, based on past rate case precedent.

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

A. Treatment of these precedential adjustments has not changed from the Commission's Orders in the Company's previous completed electric rate cases. As such, the Company has provided the adjustments themselves in Schedules to my Direct Testimony, and support for these adjustments, including a detailed description of each adjustment and supporting materials, in the workpapers identified in Exhibit___(BCH-1), Schedule 10. This organization is intended to facilitate the review of and full support for each adjustment within the identified workpaper.

B. Rate Case Adjustments

1) Dues: Chamber of Commerce

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

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

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

- Schedule 6B, page 1, row 40, column 11,
- Schedule 10, page 1, row 15, column 5,
- Volume 3, Section VIII Adjustments, Tab A11.

2) Credit Card AutoPay

Q. PLEASE DESCRIBE THE CREDIT CARD AUTOPAY ADJUSTMENT.

A. The credit card autopay adjustment is a proposal the Company is making in the pro forma 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. Because this program would be new for the Company, we are proposing to establish a baseline amount of credit card fees for the South Dakota jurisdiction in base rates and track actual costs for the South Dakota jurisdiction above or below that baseline for recovery or return to customers in a future rate case. Mr. Krug also discusses the Company's proposal in his Direct Testimony.

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. 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. The Company currently estimates annual total electric credit card fees of approximately $0.4 million, once customers are no longer charged individually for each transaction. We propose to establish this amount in our pro forma year revenue requirement and track actual annual fees above and/or below this baseline between initiating the program (approximately January 1, 2023) and our next South Dakota electric 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 electric utility service, making it consistent with the practices of other businesses. The tracker will ensure the Company does not over- or under-collect credit card fees in the pro forma 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.

Q. HOW IS THIS ADJUSTMENT IMPACTING THE PRO FORMA YEAR REVENUE REQUIREMENTS?

A. This adjustment impacts the pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 1, row 40, column 7;
- Schedule 10, page 1, row 16, column 5,
- Volume 3, Section VIII Adjustments, Tab A12

3) Foundation and Other Donations

Q. PLEASE DESCRIBE THE CHARITABLE CONTRIBUTION ADJUSTMENT.

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

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

- Schedule 6B, page 1, row 40, column 13,
- Schedule 10, page 1, row 17, column 5
- Volume 3, Section VIII Adjustments, Tab A13.

4) Revenue Year End

Q. PLEASE DESCRIBE THE REVENUE YEAR END ADJUSTMENT.

A. As I discussed earlier, the Company is proposing to use year end rate base for plant-related components. As a result an adjustment is needed to increase present revenue to align with that change in plant related rate base and account for customer growth during the pro forma year.

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

- Schedule 6B, page 2, row 40, column 18,
- Schedule 10, page 1, row 18, column 5
- Volume 3, Section VIII Adjustments, Tab A14.

5) End of Life (EOL) Nuclear Fuel Update

Q. PLEASE DESCRIBE THE EOL NUCLEAR FUEL UPDATE ADJUSTMENT.

A. The EOL Nuclear Fuel adjustment reflects a change in nuclear fuel expense for nuclear fuel commodities associated with the last few reloads at each unit. These revised cost estimates were the result of the Company's updated study that revised the cost of the unburned nuclear fuel at the time of shutdown of our nuclear generating plants. Support for this change is provided by Ms. Wold in her Direct Testimony.

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

- Schedule 6B, page 1, row 40, column 12;
- Schedule 10, page 1, row 19, column 5;
- Volume 3, Section VIII Adjustments, Tab A15.

6) Incentive Compensation

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

A. We have adjusted pro forma year costs to include the costs for the long-term incentive (LTI) compensation related to Company achievement of environmental goals and time-based employee retention incentives, and exclude the costs for all Annual Incentive Plan amounts above 20 percent of each individual's base pay. Company witness Mr. Krug supports this adjustment in his Direct Testimony.

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

- Schedule 6B, page 1, row 39, column 12,
- Schedule 10, page 1, rows 20-22, column 5
- Volume 3, Section VIII Adjustments, Tabs A16-18.

7) Late Payment

Q. WHAT ADJUSTMENTS HAVE YOU MADE TO THE LATE PAYMENT REVENUE INCLUDED IN THE PRO FORMA YEAR?

A. We have adjusted pro forma year costs to remove all late payment revenues from the rate case pro forma year. This treatment is consistent with the 30 day cap on revenue lag days included in the cash working capital calculation discussed in Section IV.D above.

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

- Schedule 6B, page 1, row 40, column 15,
- Schedule 10, page 1, rows 23, column 5,
- Volume 3, Section VIII Adjustments, Tab A19.

8) Decommissioning

Q. PLEASE DESCRIBE THE DECOMMISSIONING ADJUSTMENT TO RATE BASE.

A. This adjustment updates the pro forma year to include the impact of increasing the nuclear decommissioning accrual. This adjustment is further supported by Ms. Wold in her Direct Testimony.

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

- Schedule 6B, page 1, row 40, column 8,
- Schedule 10, page 1, row 24, column 5
- Volume 3, Section VIII Adjustments, Tab A20.

9) Depreciation Study - Transmission, Distribution, and General

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

A. This adjustment updates the 2021 pro forma year to include the impact of the Company's 2017 Depreciation Study related to TD&G. This adjustment is further supported by Ms. Wold in her Direct Testimony.

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

- Schedule 6B, page 1, row 40, column 10,
- Schedule 10, page 1, row 25, column 5
- Volume 3, Section VIII Adjustments, Tab A21.

10) Depreciation Study – Remaining Life

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

A. This adjustment updates the 2021 pro forma year to include the impact of the Company's 2021 Depreciation Study. This adjustment is further supported by Ms. Wold in her Direct Testimony.

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

- Schedule 6B, page 1, row 40, column 9,
- Schedule 10, page 1, row 26, column 5
- Volume 3, Section VIII Adjustments, Tab A22.

11) PI EPU Recovery

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

A. This adjustment updates the 2021 pro forma year to include the impact of the abandoned Prairie Island Extended Power Uprate (PI EPU) project costs over the remaining life of the plant through an amortization expense. Consistent with past precedent in South Dakota for recovery of abandoned plant cost, the Company created a deferral tracking the costs. Company Witness Ms. Mandich discusses the prudence of the Company's decision to abandon the PI EPU project in her Direct Testimony.

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

- Schedule 6B, page 2, row 40, column 16,
- Schedule 10, page 1, row 27, column 5
- Volume 3, Section VIII Adjustments, Tab A23.

12) Plant Annualization

Q. PLEASE DESCRIBE THE PLANT ANNUALIZATION ADJUSTMENT.

A. This adjustment updates the 2021 pro forma year to include the impact of the Company's proposed year end rate base as discussed in Section IV. This adjustment reflects an annualized amount of depreciation expense for the pro forma year to align with the depreciation expense that will occur when rates are implemented in 2023.

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

- Schedule 6B, page 2, row 40, column 17,

- Schedule 10, page 1, row 28, column 5
- Volume 3, Section VIII Adjustments, Tab A24.

13) Transmission ROE

Q. PLEASE DESCRIBE THE TRANSMISSION ROE ADJUSTMENT.

A. Since 2013 there have been two complaints filed asking FERC (FERC Docket Nos. EL14-12 and EL15-45) to reduce the ROE used in the transmission formula rates of jurisdictional MISO transmission owners. While one of the complaints has been resolved at FERC, the other is still pending. The Company believes a determination at FERC on this matter should not impact the retail jurisdiction, and the cost of capital should be treated consistently across our rate base; therefore, we are proposing this adjustment to calculate the net transmission revenue credit using the ROE approved by the Commission in this case. For purposes of this filing, the adjustment was prepared based on the last South Dakota authorized ROE. In final compliance, the Company will make an adjustment to reflect the final authorized ROE in this case.

This adjustment includes the impact on Attachment O, GG and MM from the MISO Transmission Formula Rate, which will be partially offset in the TCR Rider removal of MISO Regional Expansion Criteria and Benefits (RECB) revenue and expenses discussed in Section VII.D, Rider Removals of my testimony. This adjustment impacts the pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 2, row 40, column 19,
- Schedule 10, page 1, row 29, column 5,
- Volume 3, Section VIII Adjustments, Tab A25.

C. Amortizations

14) COVID Deferral

Q. PLEASE DESCRIBE THE COVID DEFERRAL AMORTIZATION.

A. The Company has been deferring bad debt expense in excess of the amount included in the 2013 pro forma year in Docket No. EL14-058 and reporting that impact in Docket No. GE20-002. This amortization adjustment represents an amortization of the total deferred balance as of March 31, 2022. We propose to collect this amount over the three years consistent with rate case expenses.

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

- Schedule 6B, page 2, row 40, column 20,
- Schedule 10, page 1, row 32, column 5
- Volume 3, Section VIII Adjustments, Tab A26.

15) Income Tax Tracker Amortization

Q. PLEASE DESCRIBE THE INCOME TAX TRACKER AMORTIZATION.

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

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

- Schedule 6B, page 2, row 40, column 16,
- Schedule 10, page 1, row 33, column 5

- Volume 3, Section VIII Adjustments, Tab A27.

16) NOL Tax Reform Regulatory Amortization

Q. PLEASE DESCRIBE THE NOL TAX REFORM REGULATORY AMORTIZATION.

A. The Commission's Order in Docket No. GE17-003 approved the Company's proposed amortization level included in the TCJA refund calculation. This is being amortized over 23 years.

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

- Schedule 6B, page 2, row 40, column 22,
- Schedule 10, page 1, row 34, column 5
- Volume 3, Section VIII Adjustments, Tab A28.

17) Rate Case Expenses

Q. PLEASE DESCRIBE THE RATE CASE EXPENSES AMORTIZATION.

A. The Company requests approval of $1.238 million of projected direct expenses associated with this rate case docket and a three-year amortization period. In addition, the Company is including deferred costs from the rate case settlement in 2014 totaling $113 thousand to be amortized over the same three-year amortization period. In total this results in an annual amortization amount of $444 thousand. A three-year amortization period is consistent with our requested amortization period for other amortizations in this rate case.

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

- Schedule 6B, page 2, row 40, column 23,

- Schedule 10, page 1, row 35, column 5
- Volume 3, Section VIII Adjustments, Tab A29.

D. Rider Removals

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

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

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

A. The Company currently uses four cost recovery riders:

- Infrastructure Recovery Rider;
- Transmission Cost Recovery (TCR) Rider;
- Demand Side Management (DSM); and
- Fuel Cost Rider (FCR)

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

A. The Company proposes:

- Continued use of the Infrastructure Rider for recovery of costs related to ongoing and future infrastructure projects.
- Cost for all existing Infrastructure Rider projects will be moved to base rates upon implementation of final rates in this case.
- Continued use of the TCR Rider for recovery of costs associated with ongoing and future transmission projects and MISO RECB Schedule

26 and 26A net revenues. Costs for all in-service projects[2] will be moved to base rates upon implementation of final rates in this case.

- Continued use of the DCM in its current form
- Continued use of the FCR in its current form.

These proposals are consistent with the rider filings we made during 2021 in our separate rider dockets.

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

A. The rider revenue recovery included in the pro forma year is shown in Table 6 below.

Table 6
Cost Recovery of Rider Projects
($ in millions)

	Inf. Rider	TCR Rider
2021 Revenue	$25.8	$7.5
Year End Revenue Adjustment	0.5	0.1
Incremental Rider Recovery for 2022 and 2023	7.5	0.1
Rider Removals		0.2
Total Rider Revenue	$33.8	$7.9

18) Infrastructure Rider

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE INFRASTRUCTURE RIDER IN THE PRO FORMA YEAR?

A. As described earlier, we propose to:

[2] In-serviced projects reflects any project that was placed in-service before 12/31/2021.

- Continue recovery of costs related to ongoing and future infrastructure projects.
- Cost for all existing Infrastructure Rider projects will be moved to base rates upon implementation of final rates in this case.

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE INFRASTRUCTURE RIDER IN THE PRO FORMA YEAR?

A. As described earlier, we propose to move all 98 capital projects currently recovered in the Infrastructure Rider into base rates as part of the rate case. Since all projects will move to base rates, no adjustment is necessary for the pro forma year. Support for the complete list of projects we propose to move to base rates can be found in Volume 3, Section VIII Adjustments, Tab A28. As I mentioned earlier, the Company is proposing to continue use of the Infrastructure rider going forward.

19) TCR Rider

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

A. We are proposing continued use of the TCR Rider during the rate plan period, which includes transmission projects and MISO RECB Schedule 26 and 26A revenues and expenses. In our 2022 TCR Rider filing, we requested recovery for a total of 26 projects that to date have not yet been included in base rates. With this filing, the pro forma year reflects our proposal to move all in-serviced projects that are currently in the rider into base rates. The costs and revenues for the remaining ongoing transmission projects and MISO RECB would continue to remain in the TCR Rider. Support for the complete list of projects we propose to move to base rates and remain in the rider can be found in

Volume 3, Section VIII Adjustments, Tab A31. As I mentioned earlier, the Company is proposing to continue use of the TCR Rider going forward.

Q. PLEASE DESCRIBE THE TCR RIDER REMOVAL ADJUSTMENT.

A. The TCR Rider removal adjustment removes all costs and revenues from the pro forma year jurisdictional cost of service for the MISO RECB that will continue cost recovery in the rider after the implementation of final rates in this case. The ongoing projects that will remain in the TCR do not have any revenue requirement impacts in the 2021 historical test period, therefore no rider removal is necessary for those projects. The TCR Rider pro forma year adjustment ensures no double recovery of these costs. The adjustment has a net zero impact on the pro forma year revenue requirements, as we expect full recovery in the TCR Rider. Support for the adjustment can be found on:

- Schedule 6B, page 2, row 40, column 24,
- Schedule 10, page 1, row 39, column 5
- Volume 3, Section VIII Adjustments, Tab A31.

As stated above, we propose to move all in-serviced projects into base rates at the conclusion of this case. Thus no adjustment to pro forma year costs is necessary for these projects.

E. Known and Measurable Adjustments

Q. DID YOU FURTHER ADJUST THE BASE 2021 DATA TO DEVELOP THE PRO FORMA YEAR?

A. Yes. I made additional pro forma known and measurable adjustments to the 2021 unadjusted test year data. These adjustments were made for various capital projects, wages, and property taxes, and are necessary to have final rates reflect the cost of service at the time the final rates become effective.

Q. WHAT STANDARD DOES THE COMMISSION APPLY WHEN ASSESSING WHETHER TO MAKE AN ADJUSTMENT FOR A KNOWN AND MEASURABLE CHANGE?

A. The purpose of a rate case is to establish rates that reasonably reflect the revenues and expenses that will be experienced at the time rates go into effect. A historical test period, here 2021, is helpful for providing certainty as to past revenues and expenses but does not, by itself, reflect the revenues and expenses at the time rates go into effect in January 2023. Therefore, it is necessary to adjust the 2021 historical information to reflect known and measureable changes that will occur in 2022 and 2023. The process of using a historical test period adjusted for known and measureable changes occurring within 24 months after the end of the historical period is expressly authorized by Commission Rule 20:10:13:44, which provides in part:

> However, no adjustments shall be permitted unless they are based on changes in facilities, operations, or costs which are **known with reasonable certainty and measurable with reasonable accuracy** at the time of the filing and which will become effective within 24 months of the last month of the test period used for this section and unless expected changes in revenue are also shown for the same period. (Emphasis added.)

For the requested known and measureable changes I provide discussion of the facts that make the project known with reasonable certainty and measureable with reasonable accuracy.

Q. HOW DOES THE COMPANY'S CAPITAL BUDGET PROCESS SUPPORT THE KNOWN AND MEASURABLE ADJUSTMENTS?

A. The capital planning process involves a bottom-up analysis of needs and priorities on the part of the business areas as they develop capital budgets for review and approval. In this process, achieving the balance of funding key strategic priorities, maintaining base operations, and minimizing impacts on customer rates is important. Once proposed, project expenditures are identified, developed, and reviewed in the context of the Company's overall resources and discussed at planning meetings to determine how projects should be prioritized and which are ultimately included in an approved budget. We also assess overall cost levels in relation to inflation, which provides a helpful benchmark for reasonable increases. This allows us to ensure the most important priorities are met while keeping overall costs reasonable.

Q. PLEASE DESCRIBE IN MORE DETAIL THE CAPITAL BUDGET PROCESS FOR BUSINESS AREAS.

A. Business areas develop a capital budget for each project, including capital expenditures, in-service dates, deferred taxes, depreciation expense, and other related costs. Business area management reviews the developing budgets several times during the budgeting cycle. These reviews may consider:

- the analysis of long-term trends;
- discussion of what costs should be reduced based on process efficiencies or changing business requirements;
- identification of cost pressures and business risks;
- emerging regulatory requirements; and
- alignment with strategic objectives.

These management reviews are intended to ensure the budget is a reasonable and representative forecast of costs for the budget period. Business area budgets are consolidated, and a full report of capital program spend, including program descriptions and budget assumptions, are sent to the Investment Review Committee (IRC). The IRC takes into consideration rate and customer impacts, cost pressures, emergent issues, priorities presented by the business areas, and areas of strategic and business risk to our stakeholders. They also consider regulatory requirements and operational needs at the state level, the financial position of the operating company, and key strategic decisions that need to be made in the near future. These overall reviews of expenditures at the corporate level are conducted to balance needs across business areas and develop and approve budgets necessary to support an appropriate portfolio of projects from an operating company perspective, and the work necessary to continue to provide safe reliable service to customers.

Q. WHAT OCCURS AFTER REVIEW OF A PROJECT BY THE IRC?

A. For projects having capital expenditures greater than $10 million but less than $20 million, the IRC may approve the project, seek more information, or request that the business area re-evaluate certain assumptions before the project is included in the Company's budget. For example, the IRC may request additional information regarding such questions as how the business area is optimizing spending and in-service plans, how proposals compare to business area priorities, what alternatives were considered, how proposals are consistent with overall business strategy, and risk issues. For projects having capital expenditures greater than $20 million, after review by the IRC, a project will either be recommended for presentation to the Financial Council for approval or the business area will be asked to re-evaluate various assumptions before proceeding in the budget governance process. In addition, the IRC reviews projects with variances of more than 15 percent or 20 percent (depending on the size of the project) from their original approval.

Q. IF A PROJECT OF THE STATED THRESHOLDS IS APPROVED BY THE IRC, WHAT PROCESS DOES THE FINANCIAL COUNCIL UNDERTAKE IN ITS REVIEW?

A. The same iterative process used up to this point is repeated at the Financial Council, meaning additional research and analysis may be required and/or budget adjustments made. At the conclusion of the Financial Council review sessions, the business areas make any resulting adjustments, the budgets are considered final, and the final budgets are presented to the Boards of Directors for approval.

Q. PLEASE DESCRIBE THE APPROVAL OF BUDGETS BY THE XCEL ENERGY AND NSPM BOARDS OF DIRECTORS.

A. After Financial Council review and approval, the five-year capital budget is presented to the Xcel Energy Board of Directors. This review is focused around the upcoming year, as well as major changes compared to the previous year's five-year budget. The Board of Directors also reviews and determines whether to approve any new projects with total project spend in excess of $50 million, and any previously-approved project that is seeking re-approval because of significant changes to overall spend.

As part of a separate process, the NSPM Board of Directors approves the upcoming year's total capital budget, all new projects greater than $50 million, and the upcoming year's O&M budget. Because members of NSPM's Board of Directors also hold seats on the Financial Council, they also review and approve the full five-year O&M and capital budgets as part of that separate process. Thus the NSPM Board of Directors has multiple opportunities to review, question, and ultimately approve the Company's budget.

Q. HOW DOES THIS BUDGET PROCESS CONTRIBUTE TO THE REASONABLE CERTAINTY AND ACCURACY OF THE KNOWN AND MEASURABLE ADJUSTMENTS?

A. It is a robust and iterative process designed to balance needs across business areas and support an appropriate portfolio of projects necessary to continue to provide safe reliable service to customers. The intensive review of the capital budget by individuals with different roles and functions in the Company ensures that the capital budgets are of reasonable certainty and are as accurate as possible.

20) Capital Projects

Q. WHAT ADJUSTMENTS DID YOU MAKE WITH RESPECT TO CAPITAL PROJECTS THAT WENT INTO SERVICE IN LATE 2021 OR WILL GO INTO SERVICE IN 2022 OR 2023?

A. I made adjustments to reflect the 2023 revenue requirements for capital projects that went into service either late in 2021 or in 2023. The adjustments reflect the incremental revenue requirement cost components for 2023 over the revenue requirement cost components (e.g. plant, reserve, deferred and depreciation), if any, already included in the 2021 unadjusted test year.

Q. ARE THE ADJUSTMENTS FOR 2022 AND 2023 INCREMENTAL REVENUE REQUIREMENT CONSISTENT?

A. No, consistent with the discussion in Section IV.A above, the K&M capital adjustments for 2023 represent incremental costs from a time period that coincides with the time the rates are expected to be in effect. Therefore, the

2023 incremental revenue requirements are calculated using a 13-month average. The 2022 incremental revenue requirements are calculated consistent with the 2021 actual rate base using year-end rate base.

Q. PLEASE DESCRIBE THE KNOWN AND MEASUREABLE CAPITAL ADJUSTMENTS.

A. A description of each of the capital adjustments is shown in Exhibit___(BCH-1), Schedule 11.

These adjustments impact the pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 2, row 40, column 25,
- Schedule 10, page 2, rows 46-71, 73-77, column 5,
- Schedule 12
- Volume 3, Section VIII Adjustments, Tab K&M1.

21) Property Taxes

Q. PLEASE DESCRIBE THE PROPERTY TAXES ADJUSTMENT.

A. Property taxes incurred in the prior year and are paid out in the current year. Thus, property taxes incurred in 2021 and 2022 will be paid out in 2022 and 2023, respectively. This adjustment captures the expected incremental increase in property tax payments for 2023 compared to 2021.

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

- Schedule 6B, page 2, row 40, column 26,
- Schedule 10, page 2, row 72, column 5,
- Volume 3, Section VIII Adjustments, Tab K&M2.

22) Wage Adjustment

Q. PLEASE EXPLAIN THE WAGE ADJUSTMENT AND WHY IS IT CONSIDERED KNOWN AND MEASUREABLE.

A. The Company develops a base pay budget using headcount and historic and market base pay increases as part of its regular budgeting process. This adjustment captures the increases in both Union and Non-Union wages developed in that budget.

The Company's base pay budget assumes a three percent increase for non-bargaining employees. Surveys from five different sources demonstrate that a three percent increase in base pay is comparable to what the market has been projecting recently. Wage increases are announced and implemented each March. Therefore, we know that the average increase for 2022 is 3.0 percent. We will not know the actual percent increase for 2023 until March of 2023; however, this adjustment assumes an additional three percent increase in 2023 as supported by the market surveys mentioned above.

We have completed contract negotiations with our union employees and the wage increases for both 2022 and 2023 are known and measurable. The increase for 2022 and 2023 is three percent per year. These wage increases were applied to the actual union labor costs for 2021 to arrive at the adjustment amount.

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

- Schedule 6B, page 2, row 40, column 19,
- Schedule 10, page 2, row 78, column 5,
- Volume 3, Section VIII Adjustments, Tab K&M3.

F. Secondary Calculations

Q. WHAT IS THE NATURE OF THE SECONDARY CALCULATIONS?

A. Secondary Calculations include an adjustment for Cash Working Capital and an adjustment for Net Operating Loss. In both cases, the adjustment is dependent on the cumulative effect of all of the other adjustments in the case. The impacts of these adjustments are explained and quantified below. However, each adjustment will be recalculated once the final list of Commission-approved adjustments is complete to determine the final impact.

23) Cash Working Capital

Q. PLEASE EXPLAIN THE CASH WORKING CAPITAL ADJUSTMENT.

A. As discussed earlier in Section IV.D, Other Rate Base, the Company has incorporated a secondary calculation to apply the various revenue lag days and expense lead days to the various income statement components to result in the appropriate cash working capital rate base adjustment. All of the adjustments made in developing the pro forma year affect the cash working capital requirements. As a result, it is necessary to recalculate the change in the cash working capital incorporating the effects of those adjustments. Once the final Commission approved adjustments are known, the cash working capital balance will be recalculated, and this adjustment will be revised as necessary.

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

- Schedule 6B, page 2, row 40, column 28,
- Schedule 10, page 2, row 42, column 5,
- Volume 3, Section VIII Adjustments, Tab A32.

24) Net Operating Loss

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

A. The income tax determination is currently in a NOL position. This means that more deductions exist than are needed in the pro forma year. The Company also has federal tax credits that have been deferred and tracked for use in future periods. NOLs, unused tax credits, and the associated ratemaking treatment are discussed in detail earlier in my testimony in Section V.D.

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

A. Yes. The Company is utilizing NOLs and federal tax credits during the pro forma year, but due to the amount of federal tax credits earned during the year, the DTA is increasing. As noted previously in my testimony, any changes in the revenues, expenses, or capital structure will cause the income tax calculation to be changed. This could, in turn, affect the timing of the DTAs being generated or consumed and added to or removed from rate base.

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

- Schedule 6B, page 2, row 40, column 29,
- Schedule 10, page 2, row 43, column 5,
- Volume 3, Section VIII, Tab A33.

Q. WERE ADDITIONAL REVENUES ASSOCIATED WITH A RATE INCREASE CONSIDERED WHEN CALCULATING THE IMPACT OF THE NOL ON THE PRO FORMA YEAR REVENUE REQUIREMENT?

A. Yes. The Company did include the additional revenues it is seeking in this proceeding when calculating the NOL adjustment.

Q. WHAT IS REQUIRED TO FINALIZE THE NOL ADJUSTMENT AT THE CONCLUSION OF THIS CASE?

A. Once all items of revenue and expense have been determined in this case, a recalculation of the NOL is necessary to determine the level of deductions that must be carried forward to a future period. As with the current determination, the recalculation at the end of the case will be affected by the tax depreciation deductions, annual deferred tax expense, and the accumulated deferred tax balance.

G. Rebuttal Adjustments

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION?

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

25) Economic Development Labor

Q. WHAT IS THE ECONOMIC DEVELOPMENT LABOR ADJUSTMENT?

A. The Commission allows the Company to recover 50 percent of its current economic development expense up to $100,000. This recovery cap is designed to allow the Company to recover both the payments made to various organizations and also the administrative cost associated with managing the program. The Company's practice has been to provide the entire $100,000 in authorized expenses to these organizations. However, the Company inadvertently neglected to remove the estimated administrative costs associated with Economic Development activities from the unadjusted 2021 O&M costs.

The Company will remove approximately $14,000 in Economic Development administrative costs and provide supporting documentation in its Rebuttal Testimony.

VIII. COMPLIANCE MATTERS

Q. DID YOU REVIEW COMMISSION ORDERS AS PART OF THE DEVELOPMENT OF THE PRO FORMA YEAR REVENUE REQUIREMENT?

A. Yes. The following list briefly describes the various Commission Orders that were reviewed and addressed in preparing the pro forma year. The compliance matrix included as Exhibit___(ADK-1), Schedule 2 to the testimony of Mr. Krug documents how our rate case filing includes information submitted in compliance with these prior Commission orders.

A. Rate Moratorium

In the Commission-approved Settlement Stipulation in Docket EL14-058, the Company agreed to a rate moratorium such that the Company would not file a petition to increase base rates for electric service, for rates proposed to be in effect prior to January 1, 2017. This application proposes new rates to be in effect on January 1, 2023, and therefore we have complied with this requirement.

B. Post-Retirement Medical Benefits (OPEBs) – Pay as You Go

In Docket No. EL11-019, the Commission reaffirmed its position to not use accrual accounting and instead to use pay as you go as the appropriate mechanism for recovering the cost of OPEBs. We reflected that decision in our 2021 pro forma year and therefore no further adjustment is needed to conform to this requirement.

C. Non-Asset Based Margins

Non-asset based transactions are wholesale (trading) transactions undertaken to obtain margins from purchases and sales of energy unrelated to meeting the energy needs of our native load customers. The only transactions that qualify as non-asset based are third-party supplied electricity or financial transactions that are not required to meet the needs of our retail customers and that are resold. The Commission's approval of the Settlement Stipulation in Docket No. EL12-046 approved a sharing mechanism under which the Company provided 30 percent of the profit margins from non-asset trading to customers through the Fuel Clause Rider. In addition, the Company was directed to update the incremental and fully allocated cost studies in this proceeding. We have complied with both requirements. The non-asset based margins are refunded to customers through the Fuel Clause Rider and the required studies are included as Exhibit __(BCH-1), Schedule 13. Those studies indicate that the 30-percent sharing mechanism provides a reasonable balance of customer and Company interests.

D. Moving Completed TCR Rider Projects to Base Rates

In Docket No. EL11-019, the Company was directed to move the costs of completed TCR projects into the base rate revenue requirement. As discussed earlier, 26 projects recovered in the TCR Rider went into service prior to January 1, 2022, and we are proposing to move those project costs into base rates in this rate case filing, which satisfies this requirement.

E. Moving Infrastructure Rider Projects to Base Rates

The Settlement in Docket No. EL12-046 directed us to move projects into base rates "in a future rate case." As discussed earlier, 98 projects recovered in the Infrastructure Rider went into service prior to January 1, 2022 and we are proposing to move those project costs into base rates in this rate case filing, which satisfies this requirement.

F. MISO Schedule 26 Costs

In the Settlement Stipulation approved by the Commission in Docket No. EL11-019, the Company and Commission Staff agreed that Schedule 26 expenses and revenues should be removed from the unadjusted test year and included for Commission review in the TCR Rider on a going forward-basis. We have complied with that requirement and propose continued cost recovery through the TCR Rider. Therefore, the TCR Rider Removal adjustment includes a removal of both Schedule 26 revenues and expenses.

G. Nuclear Fuel Outage Deferral /Amortization

The Company has used the Commission-approved nuclear fuel outage deferral/amortization methodology. That methodology was included in the 2021 unadjusted test year and, therefore, no further adjustment was necessary.

We continue to support this mechanism as appropriate for addressing the otherwise large annual variance in cost. We can experience between one and three outages in any given year and the deferral and amortization method smooths out those variances over the useful life of the refueling outages (generally between 18 and 24 months). Amortizing the costs over that longer period also dampens the effect of increasing refueling outage costs.

IX. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION TO THE COMMISSION.

A. I recommend that the Commission determine an overall retail revenue requirement of $291.3 million and an incremental revenue deficiency of $44.1 million or 17.9 percent, based on a pro forma year with known and measureable changes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.