Direct Testimony and Schedules
Christopher J. Barthol

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. EL25-___
Exhibit___(CJB-1)

Class Cost of Service Study

June 30, 2025

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Christopher J. Barthol. I am a Rate Consultant.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. My qualifications include 14 years of regulatory experience in the areas of rate design and class cost of service. I have served as a witness before the South Dakota Public Utilities Commission, the North Dakota Public Service Commission, and the Minnesota Public Utilities Commission. I have a Bachelor of Arts in Economics from Saint Cloud State University and a Master of Science in Agricultural Economics from Purdue University. A detailed statement of my qualifications and experience is provided in Exhibit___(CJB-1), Schedule 1.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of Northern States Power Company, a Minnesota corporation (NSP, Xcel Energy, or the Company).

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

A. The purpose of my testimony is to present the Company's proposed Class Cost of Service Study (CCOSS) and sponsor Exhibit___(NSP-1), Statement O, located in Volume 1 of our Application.

Q. PLEASE SUMMARIZE THE COMPANY'S CCOSS PROPOSAL IN THIS CASE.

A. The CCOSS is done on a historic 2024 calendar year embedded cost basis which functionalizes, classifies, and allocates plant and expenses in the test year on cost-causation principles. The Company is not proposing any significant changes to the CCOSS methodology last approved by the South Dakota Public Utilities Commission. I will describe the modifications to the class allocations and the rationale for the adjustments, detail the class allocations indicated by the CCOSS, and discuss the results of the CCOSS.

II. CLASS COST OF SERVICE STUDY

A. Overview of Proposed Class Cost of Service Study

Q. HAS THE COMPANY MADE MATERIAL CHANGES TO ITS CCOSS WHEN COMPARED TO THE ONE APPROVED IN THE COMPANY'S LAST GENERAL ELECTRIC RATE CASE?

A. Other than one refinement we are proposing to the Minimum System Study, our CCOSS methodology is substantially the same as the one used by the Company and underlying the settlement approved by the Commission in Docket No. EL22-017. We updated the Company's proposed CCOSS to reflect pro forma 2024 data. Specifically, all costs have been updated to reflect 2024 weather normalized costs. The hourly load data, energy use data, and customer-related data have also been updated to reflect weather normalized sales data for 2024 and have been used to update class cost allocation factors.

Q. HAS THERE BEEN ANY CHANGE TO HOW CUSTOMER CLASSES ARE DEFINED SINCE THE COMPANY'S LAST RATE CASE?

A. No, the basic classes of service employed in the Company's CCOSS are the same class definitions consistently used by the Company in past rate cases. The basic rate classes in the class cost of service study are:

- Residential;
- Commercial Non-Demand Billed;

- Commercial and Industrial (C&I) Demand Billed; and
- Street Lighting.

In the CCOSS, the C&I Demand Billed class is further separated by voltage level.

Q. HAS THE COMPANY PROVIDED ANY OTHER DOCUMENTS EXPLAINING HOW ITS CCOSS IS DEVELOPED?

A. Yes. The Company has provided a document titled "Guide to Class Cost of Service Study," which is included with my testimony as Exhibit___(CJB-1), Schedule 2. It provides a primer on how the CCOSS was conducted, including the processes of cost functionalization, classification, and allocation. These basic processes are common to all embedded cost studies. This Guide also describes how each of the cost allocation factors was developed and identifies the cost items to which each allocator is applied.

Q. WHAT IS THE ROLE OF THE CCOSS IN THE RATEMAKING PROCESS?

A. The CCOSS allocates jurisdictional costs (in this case, costs of the Company's State of South Dakota electric jurisdiction) to customer classes using class cost allocation factors. The CCOSS measures the contribution each class makes to the Company's overall cost of service, including calculating inter-class and intra-class cost responsibilities. One of the primary goals of the CCOSS is to develop class cost allocation factors that accurately reflect cost causation. The CCOSS therefore serves as a tool for evaluating and refining the Company's rate structure, as discussed in more detail by Company witness Nicholas N. Paluck.

Q. IS THE COMPANY'S CCOSS THE APPROPRIATE TOOL FOR EVALUATING THE RATE DESIGN IN THIS CASE?

A. Yes. As discussed by Company witness Paluck, a CCOSS is the appropriate starting point for evaluating a given rate design. The Company's proposed CCOSS is appropriate because it:

- Properly recognizes that our investments in baseload generation facilities provide value to all customers, particularly our energy-intensive users;
- Accurately reflects the value of our investments in peaking capacity, transmission and distribution facilities used to meet system peak requirements;
- Recognizes the differing impacts that seasonal and time usage patterns can have on the cost of service; and
- Recognizes that certain distribution costs are incurred simply to supply service to customers regardless of the kW load they demand.

B. CCOSS Results

Q. PLEASE SUMMARIZE THE RESULTS OF THE 2024 CCOSS.

A. Table 1 below provides a summary of the 2024 test year CCOSS (the 2024 CCOSS) results at the class level, showing the resulting class cost responsibilities (as opposed to revenue responsibilities that are addressed by Company witness Paluck). A summary of the CCOSS results at the class level is also provided in Exhibit___(CJB-1), Schedule 3. However, for comparison purposes, Schedule 3 also provides the class revenue allocation proposed by Company witness Paluck. The detailed 2024 CCOSS output is shown in Exhibit___(CJB-1), Schedule 4.

These CCOSS results indicate the changes from present rates to the Company's revenue requirement that would be necessary to result in equal rates of return on investment for each class (i.e., the increase in rates necessary to produce equalized rates of return).

Table 1
Summary of 2024 Class Cost of Service Study
NSPM-South Dakota Electric Jurisdiction
($ Thousands)

UNADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	333,121	152,105	13,991	164,411	2,614
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	58	55	2	1	0
[3]	Unadjusted Operating Revenues (line 1 + line 2)	333,179	152,160	13,993	164,412	2,614
[4]	Present Rates (CCOSS page 2, line 2)	289,622	122,437	12,552	152,421	2,213
[5]	Unadjusted Deficiency (line 3 - line 4)	43,557	29,723	1,441	11,991	401
[6]	Defic / Pres (line 5 / line 4)	15.0%	24.3%	11.5%	7.9%	18.1%
[7]	**Ratio: Class % / Total %**	**1.00**	**1.61**	**0.76**	**0.52**	**1.20**

COST RESPONSIBILITIES FOR RATE DISCOUNTS

		Total	Residential	Non-Demand	Demand	Street Ltg
[8]	Interruptible Rate Discounts (CCOSS page 2, line 5)	2,073	927	4	1,142	0
[9]	Interruptible Rate Disc Cost Allocation (CCOSS page 2, line 7)	2,073	801	77	1,195	0
[10]	Revenue Requirement Change (line 9 - line 8)	0	(127)	73	54	0

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[11]	Adjusted Rate Revenue Reqt (line 1 + line 10)	333,121	151,978	14,064	164,465	2,614
[12]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	58	55	2	1	0
[13]	Adjusted Operating Revenues (line 11 + line 12)	333,179	152,033	14,066	164,466	2,614
[14]	Present Rates (line 4)	289,622	122,437	12,552	152,421	2,213
[15]	Adjusted Deficiency (line 13 - line 14)	43,557	29,597	1,514	12,045	401
[16]	**Defic / Pres Rates (line 15 / line 14)**	**15.0%**	**24.2%**	**12.1%**	**7.9%**	**18.1%**
[17]	**Ratio: Class % / Total %**	**1.00**	**1.61**	**0.80**	**0.53**	**1.20**

Q. IN TABLE 1, YOU SHOW "UNADJUSTED" AND "ADJUSTED" COST RESPONSIBILITIES. PLEASE SUMMARIZE THIS DISTINCTION.

A. The distinction between "unadjusted" and "adjusted" cost responsibilities relates to how the cost of interruptible rate discounts are reflected in the CCOSS. The method used to reflect the cost of the interruptible rate discounts is the same as that used in the Company's last rate case.

Q. WHAT IS INTERRUPTIBLE SERVICE?

A. Interruptible service is offered to customers who agree to control demand to a predetermined level whenever required by the Company.

Q. WHY DOES INTERRUPTIBLE SERVICE RECEIVE A DISCOUNT?

A. Customers who opt for interruptible service receive a discount because they are subject to curtailment under this service, which is priced to reflect the lower degree of service.

Q. HOW DOES THE COMPANY TREAT INTERRUPTIBLE SERVICE IN THE CCOSS?

A. The Company's CCOSS process treats interruptible discounts as a cost of peaking capacity and allocates that cost to classes based on firm or uninterrupted loads. As explained in previous cases, the Company views interruptible service as firm service with an attached, after-the-fact, purchased-power contract provision. Through this provision, the Company has the option to buy back all or part of a customer's regulatory entitlement to firm service. The resulting capacity purchase transactions occur when, and if, doing so is a cost-effective source of peaking capacity; this helps the Company obtain a reliable power supply portfolio at the lowest cost. This means interruptible rate discounts are really capacity-related power supply costs, and they need to be recognized as such in the CCOSS.

Q. HOW ARE INTERRUPTIBLE RATE DISCOUNTS REFLECTED IN THE CCOSS?

A. The Company has specific line items in the CCOSS model to address the allocation of interruptible rate discounts:

1. Line 8 on Table 1 above and Schedule 3, labeled "Interruptible Rate Discounts" shows the amount of the total interruptible rate discounts originating from each class. The amounts shown for each class are lost revenues from that class. These discounts reduce the revenue received from the classes and thus have the effect of increasing the revenue requirement for the classes that receive the discounts.
2. Line 9 on Table 1 above and Schedule 3, labeled "Interruptible Rate Disc. Cost Allocation" shows how the cost of interruptible rate discounts are allocated to the classes. Interruptible rate discounts are allocated using the applicable generation capacity cost allocation factor.
3. Line 10 on Table 1 above and Schedule 3, labeled "Revenue Requirement Change" shows the net change in the revenue requirement for each customer class.
4. The resulting Line 11 on Table 1 above and Schedule 3, labeled "Adjusted Rate Revenue Requirement" shows the appropriate cost of service for determining class revenue responsibilities. Finally, the adjusted revenue deficiency and percent deficiency are shown on lines 15 and 16, respectively.

C. Production Plant Stratification

Q. PLEASE DESCRIBE THE PROCESS THE COMPANY USES FOR ALLOCATING FIXED PRODUCTION PLANT COSTS.

A. The Company classifies fixed production plant into capacity versus energy-related sub-functions using a process called "Plant Stratification." Though refined over the years, this is the same process the Company has used with Commission approval since the late 1970s. This process has also been referred to in the National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manual (NARUC Manual) as the Equivalent Peaker method. This allocation method is also supported by the Commissions in Minnesota and North Dakota.

Q. WHAT IS THE MAIN ADVANTAGE OF THE STRATIFICATION METHODOLOGY?

A. This method appropriately recognizes that a significant portion of the fixed capital costs of baseload and intermediate plants are incurred to obtain fuel savings that more than offset the higher fixed costs, thereby minimizing total costs. Therefore, this methodology appropriately allocates the cost of the different types of generation in our fleet to the customers who benefit from that resource diversity.

Q. HOW DOES THE COMPANY CLASSIFY FIXED PRODUCTION PLANT INTO CAPACITY-RELATED AND ENERGY-RELATED PORTIONS?

A. The capacity-related portion of the fixed costs of owned-generation is the amount less than or equivalent to the cost of a comparable combustion turbine (CT) peaking plant (the generation source with the lowest capital cost and the highest operating cost). Since CTs are only used at peak times, they are classified as 100 percent capacity-related. The fixed generation costs that exceed the cost of a comparable CT peaking plant are sub-functionalized as energy-related. Since these costs are in excess of the CT costs, they were not theoretically incurred to obtain capacity, but rather to obtain the lower-cost energy that such plants can produce. The capacity- and energy-related portions are expressed as percentages of total fixed production plant costs.

Q. HAS THE COMPANY UPDATED ITS PLANT STRATIFICATION ANALYSIS FOR THE CURRENT CASE?

A. Yes. The Company updated the Plant Stratification analysis to reflect the current-dollar replacement costs of each plant type toward developing stratification percentages. The Company's updated plant replacement costs and the resulting capacity-energy splits are shown in Table 2 below.

Table 2
Stratification Allocation by Plant Type

Plant Type	Capital Replacement Value $/kW	Capacity Ratio	Capacity Percentage	Energy Percentage
Peaking	$1,552	$1,552 / $1,552	100.0%	0.0%
Nuclear	$7,312	$1,552 / $7,312	21.2%	78.8%
Fossil	$4,230	$1,552 / $4,230	36.7%	63.3%
Combined Cycle	$2,336	$1,552 / $2,336	66.4%	33.6%
Hydro	$8,090	$1,552 / $8,090	19.2%	83.8%
Wind	$12,593	$1,552 / $12,593	12.3%	87.7%
Solar	$3,048	$1,552 / $3,048	50.9%	49.1%

I note that Table 2 should not be interpreted to identify which resources provide more or less overall value to our customers. This table simply isolates the capacity-related cost of each resource to perform the stratification calculation.

Q. ARE THE STRATIFICATION PERCENTAGES APPLIED TO EACH COMPONENT OF THE REVENUE REQUIREMENT?

A. Yes. The process of "stratifying" the revenue requirements of fixed production plant is accomplished by applying these stratification percentages to each rate base component (*e.g.,* book investment, accumulated depreciation, accumulated deferred income taxes, construction work in progress) for each generation plant type.

D. Classification and Allocation of Distribution Plant Costs

1. Direct Assignment of Distribution Costs to the Street Lighting Class

Q. WHAT DISTRIBUTION COSTS DID THE COMPANY DIRECT ASSIGN TO THE STREET LIGHTING CLASS?

A. Consistent with past South Dakota rate cases, the Company has directly assigned all of the costs in FERC Account 373. FERC Account 373 includes all street lighting costs except for the cost of wood poles used solely by lighting in overhead distribution areas. The specific cost items included in FERC Account 373 are:

- Overhead and underground distribution lines that only serve street lighting;
- Metal and fiberglass street lighting poles in underground areas;
- Lamps and fixtures; and
- Automatic control equipment.

As shown on page 4, line 47 of Schedule 4, we directly assigned $5.2 million of FERC Account 373 costs to the Street Lighting class in the 2024 CCOSS. This direct assignment is appropriate because the costs included in FERC Account 373 are directly attributable to Street Lighting.

Q. WHAT OTHER DISTRIBUTION COSTS ARE ATTRIBUTABLE TO THE STREET LIGHTING CLASS?

A. As we did in the last rate case, the Company has conducted an analysis to determine if there are costs in FERC Account 364 that should be assigned to the Street Lighting class.

Q. WHAT COSTS ARE INCLUDED IN FERC ACCOUNT 364?

A. FERC Account 364 includes the cost of installed poles, towers, and appurtenant fixtures used for supporting overhead distribution conductors and service wires. Many of these poles have street lights attached and the cost of poles that only have street lights attached is not included in FERC Account 373.

Q. DOES ACCOUNT 364 INCLUDE MORE THAN JUST STREET LIGHTING COSTS?

A. Yes. FERC Account 364 includes the cost of 43,624 wooden poles. Company-owned street lights are attached to 3,715 of these poles, meaning 8.52 percent of the FERC Account 364 costs are at least partially attributable to street lighting. Through consultation with our Street Lighting staff, we determined that 60 percent of the lighting poles serve only Street Lighting customers (*i.e.,* they do not have facilities attached that serve other customer classes). Since these poles are only used for street lighting, it's appropriate to assign the cost of these poles to the Street Lighting class. Line 9 of Table 3 below estimates lighting pole costs that should be direct assigned to the Street Lighting class as a result of this analysis. This direct assignment is also shown in Exhibit___(CJB) Schedule 4 on page 4, line 27.

Table 3
Calculation of FERC Account 364 Direct Assignment
NSPM-South Dakota Electric Jurisdiction
($ Thousands)

Line No.	Original Plant in Service	
1	FERC 364	$83,105
2	Wood pole cost as a percent of FERC 364	73.84%
3	Total FERC Codes 364 and 365 (Line 1 x Line 2)	$61,362
4	SD Company-Owned Street Lights on Wooden Poles	3,715
5	Total SD Wooden Poles	43,624
6	Lighting Poles as % of Total Poles (Line 4 / Line 5)	8.52%
7	Lighting % x Wood pole portion of FERC 364 (Line 6 * Line 3)	$5,226
8	Percent of Lighting Poles that Only Serve Lighting	60%
9	FERC Acct Direct Assignment to Lighting (Line 7 * Line 8)	$3,135

2. *Adjustment for Percent of Customers Served by Multi-Phase versus Single-Phase Primary Distribution Lines*

Q. PLEASE DESCRIBE THE DIFFERENCE BETWEEN SINGLE-PHASE AND MULTI-PHASE PRIMARY DISTRIBUTION CONFIGURATIONS.

A. Feeders originate at distribution substations in a three-phase configuration and then often split into three, single-phase lines that serve lower usage customers (in less common instances the system may split into a two-phase configuration).

Q. WAS THE COMPANY ABLE TO QUANTIFY THE PERCENTAGE OF CUSTOMERS IN EACH CUSTOMER CLASS THAT RECEIVE SERVICE OFF THE SINGLE-PHASE PRIMARY DISTRIBUTION SYSTEM AS OPPOSED TO THE MULTI-PHASE PRIMARY DISTRIBUTION SYSTEM?

A. Yes. Based on data in the Company's Geographic Information System (GIS), the Company's Distribution staff determined that 75.6 percent of South Dakota residential customers receive service off the single-phase primary distribution system. Table 4 also shows that significantly fewer C&I customers receive service from the single-phase primary distribution system.

Table 4
Percent of Customers Served by Single-Phase and Multi-Phase Primary Distribution Lines

Primary Distribution Line Serving the Customer Premise	Customer Class			
	Residential Customers	C&I Non-Demand	C&I Demand	Lighting Customers
Single-Phase	75.6%	42.1%	14.8%	51.7%
Multi-Phase	24.4%	57.9%	85.2%	48.3%
Total	100.0%	100.0%	100.0%	100.0%

Q. HAS THE COMPANY BASED ITS CLASS ALLOCATION OF PRIMARY DISTRIBUTION LINE COSTS ON THE ABOVE UPDATED ANALYSIS?

A. Yes. Consistent with prior South Dakota rate cases, we continue to separate distribution lines into capacity and customer components using a Minimum System Study, as described in the Guide to Class Cost of Service Study, Schedule 2. As we did in the last rate case, we classified costs for primary distribution lines into single-phase and multi-phase components. We based the split on miles of single-phase and multi-phase distribution plant and their associated replacement cost (in dollars per mile). The resulting separation of costs is shown on page four of Schedule 4, lines 19-22 (overhead primary distribution lines) and lines 29-32 (underground primary distribution lines). We also created distribution line cost allocators to account for the differing usage of the single-phase portions of the system by different customer classes. Exhibit___(CJB-1), Schedule 5 shows how these allocators were developed.

3. Separation of Distribution Plant Costs into Capacity and Customer-Related Components

Q. IN THE COMPANY'S CCOSS, HOW HAVE THE COSTS FOR DISTRIBUTION PLANT BEEN CLASSIFIED?

A. Table 5 below shows how the Company has classified costs for the various distribution property units in the CCOSS. This classification is consistent with past South Dakota rate cases.

Table 5
Classification of Distribution Plant Investment

Distribution Plant Property Unit	TY 2024 SD Plant Investment ($000)	Demand Component	Customer Component
Distribution Substations	$88,889	X	
Primary Voltage Transformers	$8,769	X	
Primary Voltage Distribution Lines	$284,166	X	X
Secondary Voltage Distribution Lines	$90,684	X	X
Secondary Voltage Transformers	$40,626	X	X
Services	$43,493	X	X

Q. WHAT ANALYSIS DID THE COMPANY PERFORM TO DO THIS SEPARATION OF COSTS?

A. In this case, the Company relied on two analyses, a Minimum System Study and a Zero Intercept Study. We updated the Minimum System Study and included three new updates. First, we performed an extensive review of what equipment would be considered "minimum." Second, we performed an extensive review of the installed cost of distribution equipment. Third, we also performed a Zero Intercept Study. A Zero Intercept Study is the primary alternative method to classify the customer component of distribution costs.

Q. WHAT STEPS ARE TAKEN TO COMPLETE A MINIMUM SYSTEM STUDY?

A. The following steps are taken to complete a Minimum System Study (these steps are also described on pages 90-92 of the NARUC Manual):

Step 1: Determine the minimum sized conductor, transformer, and service installed on the distribution system.

Step 2: Determine the installed cost per unit for the minimum sized plant. Installed costs include material costs, labor costs, and equipment costs.

Step 3: Multiply the cost per unit of the minimum sized plant by the total inventory of each plant type.

Step 4: The total cost of the minimum sized plant is divided by the total cost of the actual sized distribution plant in the field. This ratio is deemed to be the customer-related portion of distribution plant investment, with the remaining balance being the demand-related portion.

Q. WHAT STEPS ARE TAKEN TO COMPLETE A ZERO INTERCEPT STUDY?

A. The steps for completing a Zero or Minimum Intercept are described on pages 92-94 of the NARUC Manual. A Zero Intercept Study requires considerably more data and analysis than a Minimum System Study. A Zero Intercept Study requires the following data:

- A listing of all the configurations of equipment installed for the following distribution property units:
  - Overhead Primary Conductor
  - Overhead Secondary Conductor
  - Overhead Transformers
  - Underground Primary Conductor
  - Underground Secondary Conductor
  - Underground Transformers
  - Primary Voltage Stepdown Transformers
- For each of the above property units, the equipment inventory is obtained for each property unit configuration.
- The maximum capacity rating for each property unit configuration.
  - Ampacity for conductors
  - kVa for Transformers
- The installed cost per unit for the most common property unit configurations.

Q. AFTER THE DATA IS ACQUIRED FOR THE ZERO INTERCEPT STUDY, WHAT IS THE NEXT STEP IN THE ANALYSIS?

A. After the data is acquired, the following steps are taken to complete a Zero Intercept Study:

Step 1: The statistical analysis technique called linear regression is applied to the data acquired for each property unit. Specifically, the variable "cost per unit" as the dependent variable (Y axis) is regressed on the variable "maximum capacity" as the independent variable (X axis). The point where the regression line crosses the Y intercept is the theoretical "zero load" cost per unit.

Step 2: The zero load cost per unit is multiplied by the total inventory of the distribution property unit.

Step 3: The installed cost per unit for the most common property configurations is multiplied by the inventory of each configuration. The resulting product is then summed for each property unit.

Step 4: The result from step 2 is divided by the result from step 3. This ratio is classified as the customer component for each property unit.

Q. HOW DID THE COMPANY ACQUIRE THE INFORMATION NECESSARY TO PERFORM THE MINIMUM SYSTEM AND ZERO INTERCEPT STUDIES?

A. In short, data on the types, configurations, sizes, and quantities of distribution equipment were obtained by querying the Company's GIS data. Data on the installed unit costs for each equipment configuration were obtained by analyzing the costs of distribution work orders that were completed over a 14-year period. The goal in this data-gathering step was to obtain installed costs for equipment configurations that comprise 90 percent of the population for a given property unit (*i.e.,* underground primary conductor). More detail on the specific data sources is provided in Schedule 6.

Q. HOW WAS THE ABOVE-MENTIONED DATA UTILIZED TO CONDUCT MINIMUM SYSTEM AND ZERO INTERCEPT STUDIES?

A. The methods, data, and results of the Minimum System and Zero Intercept Studies are shown in Schedule 6 of my testimony. Attachments A through G of Schedule 6 show the inventory of the different equipment configurations for each property unit. Attachments H through M of Schedule 6 show the graphical results of the Zero Intercept linear regression analysis for each property unit. Attachment N of Schedule 6 shows the detailed Minimum System and Zero Intercept calculations.

Q. ARE YOU PROPOSING ANY CHANGES TO THE MINIMUM SYSTEM AND/OR ZERO INTERCEPT STUDIES?

A. Yes. I am proposing to remove the demand adjustment from the Zero Intercept Study.

Q. PLEASE EXPLAIN THE DEMAND ADJUSTMENT.

A. In past rate cases, the Company assumed a 1.5 kW per customer demand adjustment for the load carrying capacity of a minimum system and applied this 1.5 kW per customer to the distribution capacity cost allocation factors.

Q. WHY ARE YOU PROPOSING TO REMOVE THE 1.5 KW PER CUSTOMER DEMAND ADJUSTMENT FROM THE ZERO INTERCEPT STUDY?

A. In the Company's 2022-2024 Minnesota Electric Rate Case (Minnesota Public Utilities Commission Docket No. E002/GR-21-630), an intervenor proposed that the Company remove the demand adjustment from the Zero Intercept Study, because this study estimates the cost of a minimum system that has no load or capacity, which means the load carrying capacity of this minimum system would be zero. The Company agreed with this proposal and is therefore proposing to remove the demand adjustment from the Zero Intercept Study.

Q. HOW DO THE RESULTS OF THE ZERO INTERCEPT AND MINIMUM SYSTEM APPROACHES COMPARE?

A. For each property unit, the table below shows the percent of costs that would be classified as customer-related using the Zero Intercept Method compared to the Minimum System Method. As shown in Table 6 below, for five of the six property units the Zero Intercept Method provides a lower customer component, while one of the six have a lower customer component using the Minimum System Method.

Table 6
Percent of Distribution Investment Classified as Customer-Related
Zero Intercept Method vs. Minimum System Method

Property Unit	% of Costs Classified as Customer-Related	
	Zero Intercept Method	Minimum System Method
Overhead Primary	24.01%	63.15%
Overhead Secondary	79.89%	95.97%
Overhead Transformers	69.09%	77.97%
Underground Primary	34.68%	63.81%
Underground Secondary	58.55%	100%
Underground Transformers	70.18%	66.72%

Q. WHICH RESULTS WERE USED IN THE COMPANY'S PROPOSED CCOSS?

A. For a given property unit a "hybrid" of the two methods was used, in that the Company used the method that provided the lower customer component, as shown in Table 7 below.

Q. WHY IS IT REASONABLE TO CLASSIFY THE CUSTOMER/CAPACITY COMPONENT OF DISTRIBUTION COSTS BASED ON A HYBRID OF APPROACHES?

A. The purpose of the study is to establish the cost of a minimally-sized distribution property unit, and then classify that minimum cost as customer related. Evaluating the two separate studies, and selecting the result which provided the lowest minimum cost, provides a conservative estimate of customer-related costs to ensure we are not overstating the customer classification.

Table 7
Customer versus Capacity Classification Applied to Distribution Plant Investment

Property Unit	% Classified as Customer-Related	% Classified as Capacity-Related
Overhead Primary (used Zero Intercept result)	24.01%	75.99%
Overhead Secondary (used Zero Intercept result)	79.89%	20.11%
Underground Primary (used Zero Intercept result)	34.68%	65.32%
Underground Secondary (used Zero Intercept result)	58.55%	41.45%
Weighted Average for Overhead and Underground Transformers*	68.05%	31.95%

* used Zero Intercept for OH Transformers; used Minimum System for UG Transformers

Q. HOW ARE THE RESULTS OF THIS ANALYSIS USED TO CLASSIFY CUSTOMER AND CAPACITY COSTS BY SUB-FUNCTION?

A. Attachment O of Schedule 6 shows how the results of the Minimum System and Zero Intercept analyses are used to separate distribution plant investment into customer- and capacity-related costs. The results as shown in column 7 of Attachment O are the inputs to the CCOSS model for the 2024 test year as shown in Schedule 4, page 4, column 1, lines 19 – 42.

4. Classification and Allocation of Other Production O&M Costs

Q. DID THE COMPANY ANALYZE THE NATURE OF OTHER PRODUCTION O&M COSTS AS PART OF THIS CASE?

A. Yes. Based on our analysis, the only Other Production O&M costs that vary directly with energy output (*i.e.,* increase or decrease based on energy output) are chemicals and water use costs. In the case of chemicals, which are used for pollution control purposes, as generator energy output increases, chemical use increases in direct proportion. Similarly, with water usage, which is used to control both boiler water quality and replace lost steam, such as for soot blowing, usage changes proportionally to energy output. Total chemical and water use costs for the 2024 test year are $0.339 million and make up only 0.9 percent of total Other Production O&M costs. The remaining $35.5 million of Other Production O&M does not vary directly with energy output.

Q. HOW DOES THE COMPANY CLASSIFY OTHER PRODUCTION O&M COSTS THAT VARY DIRECTLY WITH ENERGY?

A. The Company has classified the Other Production O&M costs that vary directly with energy usage as energy-related. This is consistent with the Company's approach in the last rate case.

Q. HOW DOES THE COMPANY CLASSIFY THE REMAINING OTHER PRODUCTION O&M COSTS?

A. Consistent with the Company's approach in the last rate case, Other Production O&M costs that originate from a specific generator are classified as capacity- or energy-related based on the Production plant investment (excluding nuclear fuel) split from the Company's Plant Stratification analysis, as shown on lines 3 and 4 on page 4 of Schedule 4. For those production expenses that do not apply to a particular generation type, the Company applies the weighted average Capacity versus Energy percentage splits. I note that there are $1.091 million in costs that are not specific to a generator type and $0.798 million of Regional Markets expenses that are split into demand and energy components based on the total plant-specific expense split. Table 8 below shows the resulting classification of Other Production O&M expenses. As shown below, 77.40 percent of costs are classified as energy-related while 22.60 percent of costs are classified as capacity-related.

Table 8
Classification of Other Production O&M Costs
NSPM-South Dakota Jurisdiction

Plant Type or Expense Type	2024 Other Prod O&M	Percent Energy	Percent Capacity	Energy-Related	Capacity-Related
Variable (Chemicals & Water Use)	$339,377	100.00%	0.00%	$339,377	$0.0
Combined Cycle	$1,110,275	33.59%	66.41%	$372,887	$737,388
Combustion Turbine	$179,932	0.00%	100.00%	$0	$179,932
Fossil	$2,979,461	63.32%	36.68%	$1,886,620	$1,092,841
Hydro	$48,771	80.82%	19.18%	$39,417	$9,354
Nuclear	$22,961,687	78.78%	21.22%	$18,089,084	$4,872,602
Wind	$6,317,496	87.68%	12.32%	$5,539,065	$778,431
Total Generation-Related Other Production O&M	**$33,936,998**			**$26,266,450**	**$7,670,548**
Corporate Other Production O&M not Assigned to Generation Type	$1,091,218	**77.40%**	**22.60%**	$844,577	$246,641
Regional Market Expense (FERC Codes 575.1 – 575.8)	$797,774	**77.40%**	**22.60%**	$617,458	$180,315
Total Other Production O&M	$35,825,990	**77.40%**	**22.60%**	$27,728,486	$8,097,504

III. TARIFF CHANGES: SECTION NO. 6 GENERAL RULES AND REGULATIONS

Q. WHAT REVISIONS ARE BEING PROPOSED IN THE COMPANY'S GENERAL RULES AND REGULATIONS TARIFFS IN THE SOUTH DAKOTA ELECTRIC RATE BOOK?

A. In addition to those revisions to the Rate Book discussed by Company witness Paluck, the Company is proposing to update certain construction charges to be more in line with current costs. These proposed tariff updates are included in Schedule 11 to Company witness Paluck's Direct Testimony and include:

- Excess Footage Charges – Section 6.5.1.A1
- Winter Construction Charges – Section 6.5.1.A2
- Dedicated Switching – Section 6.1.8

A. Excess Footage Charges—Section 6.5.1.A1

Q. WHAT REVISIONS ARE PROPOSED IN THE EXCESS FOOTAGE CHARGES?

A. There are three Excess Footage Charges specified on Northern States Power Company's South Dakota Electric Rate Book, Tariff Sheet No. 6-23 of the General Rules and Regulations. Based on current material, labor, and equipment costs, the Company is proposing increases in each, as shown in Table 9 below.

Table 9
Excess Footage Charges (Per Foot)

Type	Present	Proposed
Service Line	$7.90	$10.00
Single Phase Sec or Prim	$8.00	$10.50
Three Phase Sec or Prim	$13.90	$17.00

The cost analysis supporting these increases in charges is provided on page 2 of Exhibit___(CJB-1), Schedule 7.

B. Winter Construction Charges—Section 6.5.1.A2

Q. WHAT REVISIONS ARE PROPOSED FOR WINTER CONSTRUCTION CHARGES?

A. There are two components to the Winter Construction Charges, as indicated on Tariff Sheet No. 6-24 of the General Rules and Regulations. The Company is proposing an increase in each as shown in Table 10 below.

Table 10
Winter Construction Charges

Type	Present	Proposed
Thawing (Per Frost Burner)	$640.00	$870.00
Trenching (Per Foot)	$8.90	$18.00

The cost analysis supporting these proposed rate charges is based on current material, labor and equipment costs, and is provided on page 3 of Exhibit___(CJB-1), Schedule 7.

C. Dedicated Switching—Section 6.1.8

Q. WHAT IS DEDICATED SWITCHING?

A. Dedicated Switching is a service requested by a few large C&I customers. It typically occurs when a customer needs to perform work on their own facilities and where doing so requires that the electric service be de-energized. This service takes place at a customer-specified date and time, which is often outside normal business hours. Providing service requires taking a service crew off of normal work activities and dispatching them to de-energize the service so the customer can do their internal work. The Company's crew then restores the customer's service as soon as the customer completes their work.

Q. WHAT IS THE PROPOSED CHANGE TO THE DEDICATED SWITCHING TARIFF?

A. The Dedicated Switching tariff provides two hourly rates for this service. Based on increases in labor and equipment costs, the Company is proposing to revise these rates to reflect current costs. For Dedicated Switching Service provided on Monday through Saturday, the current rate is $300.00 per hour and the proposed rate is $800.00 per hour. The current rate for this service provided on Sundays or holidays is $400.00 per hour and the proposed rate is $1,000.00 per hour. The cost analysis supporting these increases in charges is provided on Page 4 of Schedule 7.

D. Revenue Impact of the Proposed Excess Footage, Winter Construction, and Dedicated Switching Rate Increases

Q. WHAT IS THE NET REVENUE IMPACT DUE TO THE PROPOSED INCREASES IN EXCESS FOOTAGE, WINTER CONSTRUCTION, AND DEDICATED SWITCHING CHARGES?

A. The net annual revenue impact from the increase in these rates is $57,827, as shown on page 1 of Exhibit___(CJB-1), Schedule 7. This increase in revenues is shown on lines 2 and 12 of Schedule 3 to my testimony. It is also shown on page 7, row 21 of Schedule 4 to my testimony. The proposed increase in these charges reduces the proposed increase in retail revenues, as discussed further by Company witness Paluck in his Direct Testimony.

IV. CONCLUSION

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

A. Yes.