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Direct Testimony and Schedules
Michael A. Peppin

Before the Minnesota Public Utilities Commission
State of Minnesota

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

Docket No. E002/GR-21-630
Exhibit___(MAP-1)

Class Cost of Service Study
and
Selected Rate Design

October 25, 2021

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Michael A. Peppin. My title is Principal Pricing Analyst.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. My qualifications include over 40 years of experience with Northern States Power Company, doing business as Xcel Energy (NSPM or the Company) and its predecessors in the areas of market research and cost-of-service analysis. A detailed statement of my qualifications and experience is provided as Exhibit___(MAP-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I present the proposed 2022, 2023, and 2024 Class Cost of Service Studies (CCOSSs) for the Company, as required by Minn. R. 7825.4300(C); and Order Point 17(e) of the Minnesota Public Utilities Commission's (Commission) June 17, 2013 Order in Docket No. E,G999/M-12-587.[1] Copies of these CCOSSs are included in Volume 3, Required Information of this filing (Volume 3). Additionally, I support certain rate design proposals and address several compliance matters.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I present my testimony in the following Sections:

[1] *In the Matter of the Minnesota Office of Attorney General – Antitrust and Utilities Division's Petition for a Commission Investigation Regarding Criteria and Standards for Multiyear Rate Plans under Minn. Stat. 216B.16, subd. 19*, Docket No. E,G999/M-12-587, ORDER ESTABLISHING TERMS, CONDITIONS, AND PROCEDURES FOR MULTIYEAR RATE PLANS (June 17, 2013).

- Section II discusses the compliance items related to the CCOSS and where these compliance items are addressed;
- Section III presents the Company's proposed 2022, 2023, and 2024 CCOSS and examines the methodology used in developing the CCOSSs;
- Section IV presents the Company's proposed revisions to the Windsource and Conservation Improvement Program (CIP) Riders;
- Section V presents proposed changes to the excess footage and winter construction charges listed in Section 6 – Rules and Regulations of the Minnesota Electric Rate Book;
- Section VI presents the Company's compliance for the Competitive Rate Rider (CRR); and
- Section VII is my conclusion.

II. COMPLIANCE ITEMS

Q. WHAT COMPLIANCE MATTERS WILL YOU ADDRESS?

A. In compliance with previous Commission Orders, I will address the following topics:

- Basing the D10S capacity allocator on Xcel Energy's system peak coincident with MISO's system peak;
- Excluding the loads of customers who are direct assigned the costs of specific distribution substations from calculation of the D60Sub allocator;
- Providing the Commission with the results of multiple methods for functionalizing distribution costs;
- The allocation of transmission facility costs with the D10S allocator;

- Identifying other production Operation and Maintenance (O&M) costs that vary directly with energy output and allocating the remaining costs using the stratification method;
- Providing a description of each allocation method and reasons why each method is appropriate;
- Providing data linkages in the CCOSS model and more data transparency in the model; and
- Providing CCOSS results in compliance with the Commission's multi-year rate plan Order.

Finally, the Commission also ordered that the Company report on methods to better measure system losses in this rate case.[2] This compliance requirement will be discussed in the testimonies of Company witnesses Ms. Kelly A. Bloch for the distribution system and Mr. Ian R. Benson for the transmission system.

Q. PLEASE SPECIFY THE COMPLIANCE ITEMS FROM PREVIOUS COMMISSION ORDERS THAT ARE ADDRESSED IN YOUR TESTIMONY.

A. Table 1 lists the specific order points that I address in my Direct Testimony.

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[2] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E002/GR-15-826, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 49 (June 12, 2017).

Table 1

Compliance Items from Prior Commission Decisions

Docket No.	Commission Order	Description of Compliance Item	Testimony Section
E002/GR-15-826	June 12, 2017 Order Point No. 9(b) at 68	Report on methods to measure losses	Section II
E002/GR-15-826	June 12, 2017 Order Point No. 9(e)(ii) at 68	Base the D10S capacity allocator on Xcel Energy's system peak coincident with MISO's system peak	Section II(C)(2)(a)
E002/GR-15-826	June 12, 2017 Order at 47	Exclude the loads of customers who are directly assigned the costs of specific distribution substations from the calculation of the D60Sub allocator	Section II (C)(3)
E002/GR-15-826	June 12, 2017 Order at 45	Provide the Commission with the results of multiple methods for functionalizing distribution costs	Section II (C)(7)(c)
E002/M-19-39	July 15, 2019 Order Point No. 3(C) at 22	Provide in future rate cases when Xcel Energy is including costs and revenues related to Google an update to both the overall Incremental Cost and Benefit Analysis and the Rate Case Incremental Cost and Benefit Analysis.	Section VI

III. CCOSS

A. Overview of CCOSS

Q. WHAT ARE THE MAIN CHANGES IN THE CCOSS MODEL COMPARED TO THE COMMISSION ORDER APPROVING FINAL RATES IN THE COMPANY'S MOST RECENT CASE?

A. The Company does not propose any changes to the allocation methodology as compared to the Commission's Order in the Company's last rate case (Docket No. E002/GR-15-826). We did, however, update the allocators using more recent system data, and updated the Minimum System/Zero Intercept study for the classification and allocation of distribution costs.

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 Minnesota 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 most 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 Mr. Nicholas N. Paluck.

Q. ARE THE COMPANY'S CCOSSS THE APPROPRIATE TOOLS FOR EVALUATING THE RATE DESIGN IN THIS CASE?

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

- Properly recognize that our investments in baseload generation facilities provide value to all customers, particularly our energy-intensive users;
- Accurately reflect the value of our investments in peaking capacity, transmission, and distribution facilities used to meet system peak requirements;
- Recognize the differing impact that seasonal and time usage patterns can have on the cost of service; and
- Recognizes that a portion of distribution costs are incurred to simply connect customers to the system and therefore should be allocated to customer class based on the number of customers.

Q. DOES THE COMPANY PROVIDE ANY DOCUMENTATION TO EXPLAIN HOW ITS CCOSS IS DEVELOPED?

A. Yes. Exhibit___(MAP-1), Schedule 2 includes a document titled, "Guide to Class Cost of Service Study" or "CCOSS Guide." It is a primer on how the CCOSS was conducted, including the processes of cost functionalization, classification, and allocation. This CCOSS Guide also describes how each of the cost allocation factors were developed and identifies the cost items to which each allocator is applied. As ordered by the Commission in Docket No. E002/GR-13-868,[3] the CCOSS Guide has been enhanced to detail each

[3] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at Order Point No. 37 (May 8, 2015).

allocation method used in the study. We also provide information on why each allocation method is appropriate compared to other allocation methods and the manual of the National Association of Regulatory Utility Commissioners (NARUC). We note that our CCOSS model has been refined in past years, both by Company proposals and Commission Order. We are now in a position to enhance the structure of our model for increased transparency and ease of review, and we discuss those structural enhancements below.

Appendix 1 of Schedule 2 explains how the CCOSS customer-classes were defined. It also identifies the specific costs that are not assigned to each customer class and the reasons why a given cost is not assigned or allocated to that class. This appendix is responsive to the Minnesota Department of Commerce, Division of Energy Resources (Department) Information Request (IR) Nos. 705 and 707 from the Company's 2012 rate case (Docket No. E002/GR-12-961).

Appendix 2 of Schedule 2 provides detail on the derivation and application of the "External" class cost allocation factors (those allocators that are calculated and developed outside of the CCOSS model), while Appendix 3 to Schedule 2 provides more detail on the "Internal" class cost allocation factors (those allocators based on combinations of costs already allocated to the classes using external allocators). Each appendix includes a rationale supporting each allocator. These appendices along with additional details included in Exhibit___(MAP-1), Schedules 4 and 6 are responsive to Department IR Nos. 709 through 729 from the Company's 2012 rate case (Docket No. E002/GR-12-961).

Finally, Appendix 4 of Schedule 2 provides detail on the other analyses that were conducted to provide inputs to the CCOSS study, including a description of the analysis, the data used in the analysis, and the vintage of the data. This appendix is responsive to Department IR No. 706 from the Company's 2012 rate case (Docket No. E002/GR-12-961).

B. CCOSS Results

1. 2022 CCOSS Results

Q. PLEASE SUMMARIZE THE RESULTS OF THE 2022 CCOSS.

A. Table 2 below provides a summary of the 2022 test year CCOSS (the 2022 CCOSS) results at the class level, showing the resulting class cost responsibilities (as opposed to revenue responsibilities that are addressed by Mr. Paluck). Table 2 replicates Exhibit___(MAP-1), Schedule 3. However, for comparison purposes, Schedule 3 also provides the class revenue allocation proposed by Mr. Paluck. The detailed 2022 CCOSS output is included in Schedule 4.

These CCOSS results indicate the changes from present rates 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 2

Summary of 2022 Class Cost of Service Study

NSPM-Minnesota Electric Jurisdiction

($ Thousands)

UNADJUSTED COST RESPONSIBILITIES

		Total	Resid.	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt. (CCOSS page 2, line 1)	3,650,035	1,452,065	117,272	2,047,948	32,750
[2]	Incr. Misc. Chrgs. & Late Pay (CCOSS page 7, line 21 to line 23)	1,625	1,421	52	150	1
[3]	Unadjusted Operating Revenues (line 1 + line 2)	3,651,660	1,453,486	117,324	2,048,098	32,751
[4]	Present Rates (CCOSS page 2, line 2)	3,255,688	1,252,204	111,122	1,865,676	26,685
[5]	Unadjusted Deficiency (line 3 - line 4)	395,972	201,282	6,202	182,422	6,066
[6]	Deficiency / Present Rates (line 5 / line 4)	12.2%	16.1%	5.6%	9.8%	22.7%
[7]	**Ratio: Class % / Total %**	**1.00**	**1.32**	**0.46**	**0.80**	**1.87**

COST RESPONSIBILITIES FOR RATE DISCOUNTS

		Total	Resid.	Non-Demand	Demand	Street Ltg
		[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS				
[8]	Interruptible Rate Discounts (CCOSS page 2, line 5)					
[9]	Economic Development Discount (CCOSS page 2, line 6)					
[10]	Interruptible Rate Disc. Cost Allocation (CCOSS page 2, line 7)					
[11]	Economic Dev. Disc. Cost Alloc. (CCOSS page 2, line 8)					
						HIGHLY CONFIDENTIAL TRADE SECRET ENDS]
[12]	Revenue Requirement Change (lines 10 & 11 - lines 8 & 9)	0	(3,981)	930	3,048	4

ADJUSTED COST RESPONSIBILITIES

		Total	Resid.	Non-Demand	Demand	Street Ltg.
[13]	Adjusted Rate Revenue Reqt (line 1 + line 12)	3,650,035	1,448,084	118,202	2,050,996	32,754
[14]	Incr. Misc. Chrgs. & Late Pay (CCOSS page 7, line 21 to line 23)	1,626	1,421	52	150	1
[15]	Adjusted Operating Revenues (line 13 + line 14)	3,651,660	1,449,505	118,254	2,051,146	32,755
[16]	Present Rates (line 4)	3,255,688	1,252,204	111,122	1,865,676	26,685
[17]	Adjusted Deficiency (line 15 - line 16)	395,972	197,301	7,131	185,470	6,070
[18]	Deficiency / Present Rates (line 17 / line 16)	12.2%	15.8%	6.4%	9.9%	22.7%
[19]	**Ratio: Class % / Total %**	**1.00**	**1.30**	**0.53**	**0.82**	**1.87**

Q. IN TABLE 2, YOU SHOW "ADJUSTED" AND "UNADJUSTED" COST RESPONSIBILITIES. PLEASE EXPLAIN THIS DISTINCTION.

A. The distinction between "adjusted" and "unadjusted" cost responsibilities relates to how the cost of interruptible rate discounts and economic development 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 six rate cases.

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 loads. As explained in previous rate 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 power supply costs and they need to be recognized as such in the CCOSS.

Q. How does the Company treat economic development discounts in the CCOSS?

A. Economic development discounts are treated as a reduction in revenues from the Commercial and Industrial (C&I) Demand class. As discussed in more detail below, the cost of these discounts is allocated to each customer class based on 2022 test year present revenues as ordered by the Commission in the Company's 2013 rate case (Docket No. E002/GR-13-868).

Q. How are interruptible rate discounts and economic development discounts reflected in the CCOSS?

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

1. Line 8 on Table 2 above and Schedule 3, labeled "Interruptible Rate Discounts" shows the amount of the total interruptible rate discounts originating from each class. Line 9 on Table 2 above shows the amount of economic development 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. Lines 10 and 11 on Table 2 above and Schedule 3, labeled "Interruptible Rate Disc. Cost Allocation" and "Economic Development Disc. Cost Allocation" shows how the cost of interruptible rate discounts and

economic development discounts are allocated to the classes. Interruptible rate discounts are allocated using the applicable generation capacity cost allocation factor, while economic development discounts are allocated based on 2022 test year present revenues.

3. Line 12 on Table 2 above and Schedule 3, labeled "Revenue Requirement Change" shows the net change in the revenue requirement for each customer class.
4. The resulting Line 13 on Table 2 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 17 and 18, respectively.

Q. HAS THE COMPANY PROVIDED A DOCUMENT THAT SHOWS HOW INDIVIDUAL ITEMS ARE ALLOCATED TO EACH CUSTOMER CLASS AND THE RESULTS OF THAT CLASS ALLOCATION?

A. Yes, Schedule 4 shows the detailed CCOSS results. Pages one through three provide a more detailed summary of the CCOSS results. Page one is a summary of the Company's rate base by function and a summary of the Company's income statement. Page two shows the proposed "Cost" responsibility at equal rates of return in total, by cost classification and function. Page three shows the proposed cost of service compared to the proposed rate revenue responsibility. The listing of the detailed cost allocations begins on page four. The column labeled "Alloc" lists the class cost allocator that is used to allocate costs.[4] The column labeled "FERC Accounts" specifies the FERC codes that

[4] More detail on each allocator is provided in Appendices 2 and 3 of Schedule 2 (Guide to the Class Cost of Service Study).

are being allocated.[5] Pages four through six show the allocation of costs and calculations needed to determine rate base by class. Pages seven through 12 show the allocation of costs and calculations needed for the income statement. Finally, page 13 shows the cost allocators that are generated internally in the CCOSS model, while page 14 shows the data used to calculate the external allocators.

2. 2023 and 2024 CCOSS Results

Q. IN ADDITION TO THE 2022 CCOSS, THE COMPANY HAS ALSO INCLUDED 2023 AND 2024 CCOSSS IN THIS FILING. COULD YOU EXPLAIN HOW THE 2022 CCOSS COMPARES TO THE 2023 AND 2024 CCOSSS?

A. The 2023 and 2024 CCOSSs use the same approach for allocators as the 2022 CCOSS, and they include increases in the revenue deficiency of $150.2 million and $131.2 million that reflect the respective 2023 and 2024 revenue requirement increases. Company witness Mr. Benjamin C. Halama discusses the 2023 and 2024 plan year increases in his Direct Testimony. Tables 3 and 4 below provides a summary of the 2023 and 2024 CCOSS results at the class level, showing the resulting class cost responsibilities. Table 3 replicates a portion of Exhibit___(MAP-1), Schedule 5, while Table 4 replicates a portion of Exhibit___(MAP-1), Schedule 7. For comparison purposes, Schedules 5 and 7 include the full 2023 and 2024 CCOSS summaries and the class revenue allocations proposed by Mr. Paluck. The detailed 2023 CCOSS output is included in Schedule 6. The detailed 2024 CCOSS output is included in Exhibit___(MAP-1), Schedule 8.

[5] The inclusion of the "FERC Accounts" column is in response to Department IR Nos. 709-729 from the Company's 2012 rate case (Docket No. E002/GR-12-961).

Table 3

Summary of 2023 Class Cost of Service Study

NSPM-Minnesota Electric Jurisdiction

($ Thousands)

ADJUSTED COST RESPONSIBILITIES

		Total	Resid.	Non-Demand	Demand	Street Ltg
[20]	Adjusted Rate Revenue Reqt (line 1 + line 12)	3,758,453	1,513,717	121,385	2,089,921	33,431
[21]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,876	1,635	60	180	1
[22]	Adjusted Operating Revenues (line 13 + line 14)	3,760,329	1,515,352	121,444	2,090,101	33,432
[23]	Present Rates (line 4)	3,214,206	1,246,213	109,752	1,831,563	26,677
[24]	Adjusted Deficiency (line 15 - line 16)	546,123	269,139	11,692	258,537	6,755
[25]	Deficiency / Present Rates (line 17 / line 16)	17.0%	21.6%	10.7%	14.1%	25.3%
[26]	**Ratio: Class % / Total %**	**1.00**	**1.27**	**0.63**	**0.83**	**1.49**

Table 4

Summary of 2024 Class Cost of Service Study

NSPM-Minnesota Electric Jurisdiction

($ Thousands)

ADJUSTED COST RESPONSIBILITIES

		Total	Resid.	Non-Demand	Demand	Street Ltg
[27]	Adjusted Rate Revenue Reqt (line 1 + line 12)	3,866,065	1,583,957	124,642	2,124,584	32,882
[28]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	2,097	1,823	66	206	2
[29]	Adjusted Operating Revenues (line 13 + line 14)	3,868,161	1,585,780	124,708	2,124,790	32,883
[30]	Present Rates (line 4)	3,190,814	1,242,316	108,110	1,813,729	26,659
[31]	Adjusted Deficiency (line 15 - line 16)	677,347	343,464	16,598	311,061	6,224
[32]	Deficiency / Pres Rates (line 17 / line 16)	21.2%	27.6.0%	15.4%	17.2%	23.3%
[33]	**Ratio: Class % / Total %**	**1.00**	**1.30**	**0.72**	**0.81**	**1.10**

Q. WHAT IS THE PURPOSE OF THE 2023 AND 2024 CCOSSS?

A. First, Mr. Paluck uses the 2023 CCOSS to help design 2023 and 2024 rates. Second, as mentioned above, we are required to provide a 2023 and 2024 CCOSS pursuant to Order Point 17(e) of the Commission's June 17, 2013 Order in Docket No. E,G999/M-12-587.

Q. FROM A RATE DESIGN PERSPECTIVE, IS THERE A MATERIAL DIFFERENCE BETWEEN THE 2022 CCOSS, AND THE 2023 AND 2024 CCOSSS?

A. No. The relevant rate design question is whether the additional 2023 and 2024 plan year costs materially impact the relative inter-class cost responsibilities. Tables 2, 3, and 4 above, show the 2023 and 2024 adjustments have a very small impact on the relative inter-class cost responsibilities.

To illustrate why this is the case, Lines 13 through 19 of Table 2 show the Cost Responsibilities (total and relative) for the 2022 CCOSS. Lines 20 through 26 of Table 3 and Lines 27 through 33 of Table 4 show the same data for the 2023 and 2024 CCOSSs. In particular, it is helpful to compare Line 19 for the 2022 CCOSS to the corresponding Line 26 for the 2022 CCOSS and Line 33 of the 2024 CCOSS. The ratios of class-percent-deficiency to overall-percent-deficiency are very similar between the two CCOSSs, particularly for the Residential and C&I Demand classes.

C. CCOSS Methodology

1. Transparency of the CCOSS Model

Q. HAS THE COMPANY MODIFIED ITS CCOSS METHODOLOGY SINCE THE 2013 AND 2015 RATE CASES?

A. No. The proposed CCOSSs incorporate the allocator methodology approved in the Company's two most recent case. Table 5 summarizes the major allocation decisions approved in those cases.

Table 5

CCOSS Methodology Summary

CCOSS Methodology Elements Approved in Docket Nos. E002/GR-13-868 and E002/GR-15-826
• Allocation of Other Production O&M using the "Location" method; • Classification and Allocation of All Company-Owned Wind Generation using the Plant Stratification method; • Allocation of CIP CCRC using per kWh method; • Allocation of Economic Development Costs to all Customers Based on Present Revenues; and • Calculation of the D10S Capacity Allocator Using Class Peaks that are Coincident with MISO's Peak for the Test Year.

Q. WHAT STEPS HAS THE COMPANY TAKEN TO MAKE ITS CCOSS MODEL MORE TRANSPARENT AND EASIER TO REVIEW?

A. Since the Company's 2013 rate case (Docket No. E002/GR-13-868), the Company has taken several actions to improve the transparency and ease of review of our CCOSS. These steps were discussed in detail in my Direct Testimony from our 2015 rate case (Docket No. E002/GR-15-826). For example, the CCOSS now has direct links to all inputs used in the model. Several worksheet tabs have also been added to the CCOSS that clearly identify all financial and non-financial inputs, with direct linkages for all calculations in the CCOSS model. Exhibit___(MAP-1), Schedule 9 is the "CCOSS Worksheet Tab Index" which provides a description of the contents of each of the 54 tabs to the CCOSS.

Q. DID THE COMPANY ALTER THE DEFINITION OF ITS CUSTOMER CLASSES?

A. No. The Company has used the same class definitions in its last six rate cases. More detail on the customer class definitions is provided on Appendix 1 of Schedule 2.

2. Plant Stratification

Q. PLEASE DESCRIBE HOW THE COMPANY CLASSIFIED FIXED PRODUCTION PLANT COSTS IN THE PROPOSED CCOSSS.

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. In the NARUC manual, this process has also been referred to as the Equivalent Peaker method.

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 based on the percent of total fixed costs of each generation type that is equivalent to the cost of a comparable peaking plant (the generation source with the lowest capital cost and the highest operating cost). The percent of total generation costs that exceeds the cost of a comparable peaking plant is sub-functionalized as energy-related. These costs are in excess of the capacity-related portion, and as such, were not incurred to obtain capacity, but rather to obtain the lower-cost energy that such plants can produce.

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

A. Yes. As shown in Table 6 below, the Company has updated plant replacement costs and the resulting capacity-energy splits.

Q. WHAT ARE THE APPLICABLE STRATIFICATION PERCENTAGES IN THIS CASE?

A. The Plant Stratification analysis used in this case is shown in Table 6 below. Table 6 compares the current-dollar replacement costs of each plant type towards developing stratification percentages.

Table 6

Stratification Allocation by Plant Type

Plant Type	Replacement Value $/kW	Capacity Ratio	Capacity Percentage	Energy Percentage
Peaking	$1,026	$1,026 / $1,026	100.0%	0.0%
Nuclear	$5,109	$1,026 / $5,109	20.1%	79.9%
Fossil	$2,444	$1,026 / $2,444	42.0%	58.0%
Combined Cycle	$1,514	$1,026 / $1,514	67.8%	32.2%
Hydro	$5,756	$1,026 / $5,756	17.8%	82.2%
Wind	$11,262	$1,026/$11,262	9.1%	90.9%

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 component of the revenue requirements (e.g., book investment, accumulated depreciation, accumulated deferred income taxes, Construction Work in Progress), for each generation plant type.

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

A. From a cost perspective, this method appropriately recognizes that a significant portion of the fixed costs of baseload and intermediate plants are incurred to obtain fuel savings that more than offset the higher fixed costs, thereby minimizing total costs.

a. Allocation of Capacity-Related Portion of Fixed Production Plant – the D10S Allocator

Q. WHAT WAS THE COMMISSION'S ORDER IN THE COMPANY'S LAST RATE CASE (DOCKET NO. E002/GR-15-826) REGARDING THE D10S CAPACITY ALLOCATOR?

A. The Commission's Order on the D10S allocator was as follows:

"Xcel shall base the D10S capacity allocator on Xcel's system peak that is coincident with MISO's system peak, incorporating any future changes to MISO's method for calculating the system peak."[6]

Q. PRIOR TO THIS COMMISSION ORDER, HOW WAS THE D10S ALLOCATOR CALCULATED?

A. Prior to this Commission's Order, the D10S allocator was calculated by using each customer class's forecasted loads that were in the same hour of the NSP System peak.

Q. FOR THE 2022 TEST YEAR, DOES MISO FORECAST THE HOUR AND PROJECTED PEAK FOR EACH LOCAL RESOURCE ZONE?

A. No, MISO does not provide forecast estimates of the day and hour that their peak will occur. Virtually all of the Company's load is included in MISO's Local Resource Zone 1 (LRZ1), and over 99.9 percent of the Company's capacity requirements are in that zone. Likewise, the forecast of the NSP peak that is coincident to the MISO peak is not dependent on a specific day, month, or hour, but rather the NSP System peak and MISO peak day weather conditions.

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[6] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E002/GR-15-826, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, at Order Point 9(e)(ii) (June 12, 2017).

As a result, the Company is not able to determine forecasted class loads that would be coincident with MISO's forecasted LRZ1 peak hour for the 2022-2023 test years.

Q. HOW IS EACH PARTICIPATING UTILITY'S CAPACITY REQUIREMENT DETERMINED FOR THE UPCOMING PLANNING YEAR?

A. Each utility provides a forecast of its system peak that is adjusted for a MISO coincidence factor and planning reserve margin (PRM). The PRM is determined by MISO for each planning year. Next, the Company determines its coincidence factor with the MISO LRZ1 peak based on the historical coincidence of the NSP System peak with the MISO peak. The coincidence factor for the June 2021 to May 2022 planning year is 98.83 percent. The coincidence factor for the 2022 to 2023 planning year is in the process of being updated.

Q. WITHOUT A MISO PUBLISHED PEAK HOUR FOR THE 2022 TEST YEAR, HOW DOES THE COMPANY PROPOSE TO DETERMINE CLASS LOADS TO COMPLY WITH THE COMMISSION'S ORDER?

A. In order to comply with the Commission's Order, the Company looked at the hour that MISO's LRZ1 peaked for the each of the last 12 years. The hour that LRZ1 peaked was then compared to the corresponding hourly loads for the NSP System. As shown in Table 7 below, in five of the 12 years (2009, 2011, 2015, 2016, and 2017) the hour of the NSP System peak was the same hour as the MISO LRZ1 peak. In three of the 10 years (2010, 2014 and 2018) the MISO peak coincided with NSP's second highest peak hour, and in one year each (2012, 2013, 2019 and 2020) the MISO peak coincided with NSP's fourth, third, sixth and fifth highest peak hours, respectively.

Table 7

Comparison of MISO LRZ-1 Peak Hours to NSP System Peak Hours

For 2009 - 2020

Year	MISO LRZ1 Peak Day (CST)	MISO LRZ1 Peak Hour (CST)	NSP System Peak Day (CST)	NSP System Peak Hour (CST)	Did NSP and MISO LRZ1 Peak on the Same Day and Hour?	NSP Load Ranking at the MISO LRZ1 Peak Hour
2009	23-Jun-09	13	23-Jun-09	13	Yes	1
2010	9-Aug-10	15	9-Aug-10	16	No	2
2011	20-Jul-11	16	20-Jul-11	16	Yes	1
2012	2-Jul-12	14	2-Jul-12	16	No	4
2013	26-Aug-13	14	26-Aug-13	16	No	3
2014	21-Jul-14	14	21-Jul-14	16	No	2
2015	14-Aug-15	15	14-Aug-15	15	Yes	1
2016	20-Jul-16	16	20-Jul-16	16	Yes	1
2017	17-Jul-17	17	17-Jul-17	17	Yes	1
2018	12-Jul-18	16	29-Jun-18	16	No	2
2019	15-Jul-19	15	19-Jul-19	16	No	6
2020	24-Jul-20	16	8-Jul-20	16	No	5

Q. BASED ON THE ABOVE DATA, WHAT IS YOUR CONCLUSION REGARDING THE D10S ALLOCATOR?

A. Based on 12 years of actual data, the Company is confident that using forecast class loads for the six highest NSP System peak hours for the D10S allocator would encompass the MISO peak hour.

Q. FOR THE 2022 TEST YEAR, WHAT ARE THE FORECASTED SIX HIGHEST NSP SYSTEM PEAK HOURS?

A. The Company sorted the forecast 2022 NSP System 8,760 loads by load level and the six highest loads for the 2022 test year are shown in Table 8 below:

Table 8

Ranking of Highest NSP System Six Highest 2022 MW Load Levels

Test Year 2022 Forecast

NSP System Load Level Ranking	NSP System Load Forecast (MW)	Time Interval
1	9,073	07/20/2022 4:00 PM
2	9,006	07/20/2022 3:00 PM
3	8,987	07/20/2022 5:00 PM
4	8,874	07/20/2022 2:00 PM
5	8,813	07/19/2022 4:00 PM
6	8,754	07/19/2022 3:00 PM

Based on the load forecast, the Company is confident that using the class loads for these six hours would encompass the MISO peak hour.

Q. WHAT ARE THE CORRESPONDING FORECASTED CLASS LOADS FOR THESE HOURS AND THE RESULTING D10S ALLOCATOR?

A. The forecasted coincident loads by class for the hours specified above are shown in Table 9 below along with the resulting D10S allocator:

Table 9

Minnesota MW Class Loads Coincident with

Six Highest NSP System Peak Hours

Test Year 2022 Forecast

Date & Hour	Residential	Commercial Non Demand	C&I Demand	Lighting	Total
07/20/2022 04:00 PM	2,344	159	3,292	0	5,795
07/20/2022 03:00 PM	2,186	178	3,426	0	5,790
07/20/2022 05:00 PM	2,400	139	3,098	0	5,636
07/20/2022 02:00 PM	2,036	184	3,517	0	5,737
07/19/2022 04:00 PM	2,086	152	3,179	0	5,417
07/19/2022 03:00 PM	1,928	170	3,301	0	5,399
6 hour Total	14,166	1,006	20,438	0	35,610
D10S Allocator	39.78%	2.83%	587.39%	0.00%	100.00%

b. Allocation of the Energy-Related Portion of Fixed Production Plant and Variable Production O&M Costs – the E8760 Allocator

Q. WHAT IS THE E8760 ALLOCATOR?

A. The E8760 allocator is calculated by taking each class's hourly load for all 8,760 hours of the test year and weighting it by the corresponding hourly marginal energy costs. This energy allocation method has been adopted or is under study for use in future rate cases by many Commission regulated utilities.

Q. WHAT COSTS ARE ALLOCATED USING THE E8760 ALLOCATOR?

A. The E8760 allocator has been used to allocate all costs that have been classified as being energy-related.

Q. HOW ARE THE TEST YEAR LOAD SHAPES CALCULATED?

A. The test year load shapes are calculated by adjusting historical load shapes for test year weather values. First, we used 2015 through 2019 historical load shapes to create the initial 2022 load shape. Next, we forecast 2022 weather values (Temperature Humidity Index (THI) Cooling Degree Days (CDD), and Heating Degree Days (HDD)), which are used to forecast the 2022 typical meteorological year (TMY) weather normalized (WN) class load shape templates. Then, we used specialized software that removes the magnitude of loads by turning the WN load shape into a WN percentage scalar. Finally, the specialized software takes the monthly WN energy kWh forecast and casts it on the WN percentage scalar load shape to arrive at the final 2022 WN load shape. This analysis is repeated for the 2023 and 2024 plan years and is the same methodology used in the Company's past six rate cases.

3. Allocation of Distribution Substation Costs - The D60Sub Allocator

Q. WHAT COSTS ARE ALLOCATED USING THE D60SUB ALLOCATOR?

A. The D60Sub allocator allocates the costs of distribution substations that individually serve multiple classes of customers.

Q. HOW IS THE D60SUB ALLOCATOR CALCULATED?

A. The D60Sub allocator is based on each class's maximum class coincident load levels forecast for the test year.

Q. ARE THERE OTHER DISTRIBUTION SUBSTATION COSTS THAT ARE INCLUDED IN THE RATE CASE?

A. Yes, there are 10 substations that are dedicated to serving specific large industrial customers. The costs for these substations are directly assigned to those specific customer classes.

Q. IN THE COMPANY'S LAST RATE CASE (DOCKET NO. E002/GR-15-826), THE COMMISSION ORDERED THAT LOADS FROM CUSTOMERS WHO ARE SERVED BY DISTRIBUTION SUBSTATIONS WHOSE COSTS ARE DIRECTLY ASSIGNED SHOULD BE EXCLUDED FROM THE CALCULATION OF THE D60SUB ALLOCATOR. HAS THE COMPANY MADE THE REQUIRED ADJUSTMENT TO THE D60SUB ALLOCATOR?

A. Yes, the Company agrees that excluding the peak loads of these customers more accurately reflects cost causation. The MW loads for these customers as shown in Table 10 below have been excluded from the D60Sub allocator.

Table 10

Customer Loads Excluded from the D60Sub Allocator (MW)

Customer Class and Voltage	MW Loads Excluded from D60Sub Allocator
C&I Demand Secondary Voltage	1.555
C&I Demand Primary Voltage	17.537
C&I Demand Transmission Transformed Voltage	161.56
C&I Demand Transmission Voltage	15.410

4. *Allocation of CIP Conservation Cost Recovery Charge (CCRC)*

Q. IS THE COMPANY PROPOSING TO CHANGE HOW IT ALLOCATES CIP COSTS IN THIS CASE?

A. No. Consistent with the Commission's Order in the Company's most recent rate case (Docket No. E002/GR-15-826), we allocated both the CCRC and the

CIP Adjustment Factor (CAF) using the per kWh method. In the proposed CCOSSs, CCRC costs are allocated to class using the test year sales forecast after subtracting sales to CIP exempt customers.

5. Classification and Allocation of Other Production O&M

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

A. Yes. The Commission required the Company to analyze Other Production O&M costs in order to identify those costs that vary directly with the amount of energy produced.[7]

Based on our analysis, the only Other Production O&M costs that vary directly (*i.e.,* increase or decrease based on energy output) with 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 2022 test year are $3.7 million and make up only 0.9 percent of total Other Production O&M costs. The remaining $421.8 million of Other Production O&M does not vary directly with energy output.

Q. DOES THE COMPANY'S CCOSS ALLOCATE THE DIRECTLY-VARIABLE OTHER PRODUCTION O&M COSTS BASED UPON ENERGY?

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[7] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota,* Docket No. E002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at Order Point 37 (May 8, 2015).

A. Yes. Consistent with Order Point 37 from the Company's 2013 rate case (Docket No. E002/GR-13-868), the CCOSS has classified the Other Production O&M costs that vary directly with energy usage as energy-related and classified the remaining Other Production O&M that originate from a specific generator costs based on the type of production plant associated with the costs. I note that there are $14.0 million in costs that are not specific to a generator type and $9.6 million of Regional Markets expense that is split into capacity and energy components based on how total plant-specific expense is split. Table 11 shows the resulting classification of the 2022 test year Other Production O&M costs.

Table 11

Classification of Other Production O&M Costs

NSPM-Minnesota Electric Jurisdiction

($ Thousands)

Expense Category	2022 Other Production O&M ($000)	Percent Energy	Percent Capacity	Energy-Related Portion	Capacity-Related Portion
Variable (Chemicals & Water Use)	$3,704.8	100.0%	0.0%	$3,704.8	$0.0
Fossil	$38,129.7	58.01%	41.99%	$22,117.1	$16,012.5
Combustion Turbine	$2,302.7	0.0%	100.0%	$0.0	$2302.7
Nuclear	$268,400.3	79.91%	20.09%	$214,481.1	$53,919.2
Combined Cycle	$14,208.7	32.22%	67.78%	$4,577.6	$9,631.1
Hydro	$667.2	82.17%	17.83%	$548.2	$119.0
Wind	$74,516.8	90.89%	9.11%	$67,726.0	$6,790.8
Total Generation-Specific Other Production O&M	$401,930.1	77.91%	22.09%	$313,154.9	$88,775.2
Corporate Other Production O&M not Assigned to Generation Type	$14,886.2	77.91%	22.09%	$11,582.7	$3,283.5
Regional Market Expense (FERC Codes 575.1 – 575.8)	$9,562.2	77.91%	22.91%	$7,450.1	$2,112.0
Total Other Production O&M	$426,358.5	77.91%	22.91%	$332,187.7	$94,170.8

6. *Direct Assignment of Distribution Costs to the Lighting Class*

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

A. Consistent with finding 693 from the ALJ's report in the 2012 rate case,[8] the

[8] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota,* Docket No. E002/GR-12-961, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION (July 3, 2013).

Company has directly assigned all of the costs in FERC account 373 to the Street Lighting class and a portion of the costs of FERC account 364. 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 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 $71.5 million in 2022 test year FERC Account 373 costs to the Street Lighting class in the 2022 CCOSS. This direct assignment is appropriate because the costs included in FERC 373 are directly attributable to street lighting.

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.

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

A. Yes. The 2022 CCOSS includes $523.6 million Plant in Service for FERC account 364. Analysis of the FERC account detail shows that 79.3 percent of this account is the cost of the 446,528 wooden poles. Company-owned street lights are attached to 89,552 of these poles, meaning 21.12 percent of the FERC Account 364 costs are 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 other facilities attached that serve other customer classes).

Q. BASED ON THESE CHARACTERISTICS, HOW MUCH OF THE FERC ACCOUNT 364 COST SHOULD BE DIRECTLY ASSIGNED TO THE STREET LIGHTING CLASS?

A. We directly assigned $52.7 million in 2022 test year FERC Account 364 costs to the Street Lighting class in the 2022 CCOSS. The calculation of the direct assignment is shown in Table 12 and the direct assignment is included on page 4, line 27 of Schedule 4.

Table 12

Calculation of FERC Account 364 Direct Assignment

NSPM-Minnesota Electric Jurisdiction

($ Thousands)

Line No.		
1	FERC Acct 364	$523,637
2	Wood Pole Cost as a Percent of FERC 364	79.3%
3	FERC Acct 364 Pole Cost (line 1 x line 2)	$415,497
4	MN Company-Owned Street Lights on Wooden Poles	89,552
5	Total MN Wood Poles	446,528
6	Lighting Poles as % of Total Poles (line 4 / line 5)	21.12%
7	Lighting % x FERC 364 Pole Cost (line 1 x line 6)	$87,771
8	Percent of Lighting Poles that only Serve Lighting	60%
9	FERC Acct 364 Direct Assignment to Lighting (line 7 x line 8)	$52,663

Q. IN TOTAL, HOW MUCH PLANT INVESTMENT IS DIRECTLY ASSIGNED TO THE STREET LIGHTING CLASS IN THE 2022 CCOSS?

A. In total, $118.0 million of distribution plant investment is directly assigned to the Street Lighting class in the 2022 CCOSS.

7. Separation of Distribution Costs into Capacity versus Customer Components; Results of the Minimum System and Zero Intercept Studies

Q. IN THE CONTEXT OF ALLOCATING COSTS OF DISTRIBUTION PLANT INVESTMENT, WHAT IS THE PURPOSE OF MINIMUM SYSTEM AND ZERO INTERCEPT STUDIES?

A. Minimum System and Zero Intercept are two widely used methods for determining the percent of distribution plant investment that is customer-related and allocated to class with a customer-based allocation factor, versus the percent of costs that are capacity-related and allocated to class with a demand-based allocator.

a. The Purpose and Prevalence of Classifying Distribution Costs as Customer-Related

Q. IS IT WIDELY ACCEPTED THAT ELECTRIC DISTRIBUTION COSTS SHOULD BE CLASSIFIED AS BOTH CUSTOMER- AND DEMAND-RELATED?

A. Yes. It is widely accepted at the state, regional, and national levels that distribution costs are driven by two factors: 1) the number of customers on the distribution system, and 2) the demand those customers place on the system. With regard to the national prevalence of this classification, the NARUC manual states that only demand and customer components should be considered in classifying distribution costs. Specifically, at Chapter 6, page 89 of the manual, NARUC states:

> To ensure that (distribution) costs are properly allocated, the

> analyst must first classify each account as demand-related, customer-related, or a combination of both.
>
> As indicated in Chapter 4, all costs of service can be identified as energy-related, demand-related or customer-related. Because there is no energy component of distribution-related costs, we need consider only the demand and customer components.

Page 90 of the NARUC manual goes on to say:

> Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

With respect to the regional and state prevalence of the classification, all Commissions in the four-state region (Minnesota, North Dakota, South Dakota, and Wisconsin) accept the customer- and demand-related components of distribution costs. Additionally, the Minnesota Public Utilities Commission has accepted the Minimum System method as a means to separate distribution facilities into demand and customer components since the 1980s.

Q. WHAT IS THE PURPOSE OF CLASSIFYING ELECTRIC DISTRIBUTION COSTS AS BOTH CUSTOMER- AND DEMAND-RELATED?

A. The purpose of this classification is to allocate costs according to causation. The *customer*-related portion of the distribution system makes service available to the customer. The balance of distribution system costs is *capacity*-related. The costs a utility incurs to connect a customer to the distribution grid without regard to the level of customer load is reasonably classified as customer-related and allocated based on number of customers. The capacity-related cost component – those that are not customer-related – has cost causation based on the level of power demanded by customers above the minimum customer-related level. These costs should be allocated on customer demand and are appropriate to recover through volumetric charges.

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

A. Table 13 below shows how the Company has classified costs for the various distribution property units.

Table 13

Classification of Distribution Plant Investment

Distribution Plant Property Unit	TY 2022 Plant In Service ($000)	Demand Component	Customer Component
Distribution Substations	$747,453	X	
Primary Voltage Transformers	$44,586	X	
Overhead & Underground Primary Distribution Lines	$1,967,276	X	X
Overhead & Underground Secondary Distribution Lines	$626,025	X	X
Overhead & Underground Secondary Voltage Transformers	$384,301	X	X
Service Drops	$364,895	X	X

Note that the above classification is consistent with the FERC classification as shown on page 87 of the NARUC manual with the exception of service drops. Although FERC and many other utilities classify services as being only customer-related, the Company has historically split these costs into capacity and customer-related components.

Q. IN PRIOR RATE CASES, HOW HAS THE COMPANY PERFORMED A SEPARATION OF DISTRIBUTION COSTS INTO CAPACITY AND CUSTOMER-RELATED COMPONENTS?

A. Since the 1980s, the Company has used a Minimum System Study to perform this separation. In this case, we fully updated that study and included three new components. 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. Finally, we performed a Zero Intercept Study in addition to the Minimum System Study. A Zero Intercept Study is the alternative method to determine the customer component of distribution costs.

Ms. Bloch addresses how we determined the minimum sized equipment and the unit costs for the studies, and I address how the studies were performed and the results. The Company assumed the minimum sized distribution system has a load carrying capacity of 1.5 kW per customer, the same assumption used in prior rate cases.

Q. IN TABLE 13 OF YOUR TESTIMONY, YOU NOTE THAT THE COST FOR SERVICE DROPS WAS ALSO SEPARATED INTO CUSTOMER AND CAPACITY COMPONENTS. HOW WAS THAT COST SEPARATION CONDUCTED?

A. Detailed property records on the configuration or footage of distribution service drops are not available. As a result, we were not able to conduct a detailed Minimum System or Zero Intercept Study for classifying the cost of service drops. As a substitute, we conducted a simplified Minimum System analysis as shown in Attachment P of Exhibit___(MAP-1), Schedule 10.

b. Minimum System and Zero Intercept Studies

Q. WHAT ARE THE ANALYSIS STEPS THAT 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 balance being the capacity-related portion.

The assumed minimum property unit configurations used in the Minimum System Study are shown in Ms. Bloch's Direct Testimony.

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

A. The steps for completing a Zero Intercept Study are described on pages 92 to 94 of the NARUC manual (the manual refers to it as a "Minimum-Intercept

Method"). 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; and
  - 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.

After the above data is acquired, the following analysis 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. AS DESCRIBED ABOVE, BOTH MINIMUM SYSTEM AND ZERO INTERCEPT STUDIES REQUIRE DATA ON THE INVENTORY OF DIFFERENT DISTRIBUTION PROPERTY UNIT CONFIGURATIONS, THE PER UNIT INSTALLED COSTS OF DIFFERENT CONFIGURATIONS AND ASSOCIATED LOAD CARRYING CAPACITIES. HOW DID THE COMPANY ACQUIRE THIS INFORMATION?

A. The sources of the required data and the methods used to synthesize it are described in Ms. Bloch's Direct Testimony.

c. Results of Minimum System and Zero Intercept Studies

Q. WHAT WERE THE RESULTS OF THESE STUDIES?

A. The data and results of the Minimum System and Zero Intercept studies are shown in Schedule 10 of my testimony. Attachments A through G of Schedule 10 show the inventory of the different equipment configurations for each property unit. Attachments H through M of Schedule 10 show the graphical results of the Zero Intercept linear regression analysis for each property unit. Attachment N of Schedule 10 shows the detailed Minimum System and Zero Intercept calculations.

Q. HOW DO THE RESULTS OF THE ZERO INTERCEPT STUDY COMPARE TO THE RESULTS OF THE MINIMUM SYSTEM STUDY?

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 14 below, for four of the six property units the Zero Intercept provides a lower customer component, while two of the six have a lower customer component using the Minimum System method.

Table 14

Percent of Distribution Plant Investment Classified as Customer Related

Zero Intercept Method versus the Minimum System Method

	% of Costs Classified as Customer-Related	
Property Unit	**Zero Intercept Method**	**Minimum System Method**
Overhead Primary	34.3%	63.7%
Overhead Secondary	78.6%	99.2%
Overhead Transformers	73.5%	77.4%
Underground Primary	53.0%	62.3%
Underground Secondary	59.6%	100%
Underground Transformers	87.0%	51.6%

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

A. For a given property unit, the Company used the method that provided the lower customer component as shown in Table 15 below.

Table 15

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)	35.3%	64.7%
Overhead Secondary (used Zero Intercept result)	78.6%	21.4%
Underground Primary (used Minimum System result)	53.0%	47.0%
Underground Secondary (used Zero Intercept result)	59.6%	40.4%
Weighted Average for Overhead and Underground Transformers (used Zero Intercept for OH Transformers; used Minimum System for UG Transformers)	63.3%	36.7%

Q. HOW ARE THE RESULTS USED TO SEPARATE DISTRIBUTION PLANT INVESTMENT INTO SUB-FUNCTION AND COST CLASSIFICATION?

A. Attachment O shows how the results of the Minimum System and Zero Intercept analyses are used to provide the needed cost separation. The results as shown in column 7 are the inputs to the CCOSS model for the 2022 test year as shown in Schedule 4, page 4, column 1, lines 19 – 42.

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

A. As stated earlier, 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 reasonable way to ensure we are not overstating the customer classification.

Q. WHAT WOULD HAVE BEEN THE CCOSS RESULT IF THE COMPANY USED ONE METHOD OR THE OTHER INSTEAD OF A HYBRID APPROACH?

A. Table 16 below shows a summary of CCOSS results using the three methods for separating distribution costs into customer and capacity components. In addition to the results using each of the three methods of separating distribution costs into customer and capacity components, Table 16 also shows CCOSS results assuming no separation of costs occurs and all distribution costs are treated as capacity-related. This extreme method was referred to as the Basic Customer method in the Company's last rate case (Docket No. E002/GR-15-826).

Table 16

Summary of 2022 CCOSS Results Using Different Methods For Classifying Distribution Plant Investment NSPM-Minnesota Electric Jurisdiction

($ Thousands)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
		Hybrid Method		**Zero Intercept Method**		**Minimum System Method**		**Basic Customer Method**	
Line	**Customer Class**	**$ Defic. ($000)**	**% Defic.**	**$ Defic. ($000)**	**% Defic.**	**$ Defic. ($000)**	**% Defic.**	**$ Defic. ($000)**	**% Defic.**
1	Residential	197,301	15.8%	199,019	15.9%	229,896	18.4%	109,879	8.8%
2	Non-Demand	7,131	6.4%	7,282	6.6%	9,681	8.7%	145	0.1%
3	Demand	185,470	9.9%	183,593	9.8%	150,273	8.1%	280,120	15.0%
4	Street Ltg	6,070	22.7%	6,077	22.8%	6,121	22.9%	5,828	21.8%
5	Total	395,972	12.2%	395,972	12.2%	395,972	12.2%	395,972	12.2%
6	Cost Based Residential Customer Chg. ($ per Residential customer per month)	$19.79		$20.06		$24.84		$5.10	

Columns 1 and 2 above show the dollar deficiency and percent deficiency by customer class using the proposed hybrid method for separating distribution costs into customer and capacity components. Columns 2 and 3 show results using the Zero Intercept method, while columns 5 and 6 show results using the Minimum System method, and columns 7 and 8 show results using the Basic Customer method. Line 6 of Table 16 above shows what the cost-based residential customer charge would be using each method.

Q. IN THE LAST RATE CASE, ONE OF THE PARTIES ASKED THE COMPANY IN DISCOVERY TO SHOW CCOSS RESULTS USING A "PEAK AND AVERAGE" METHOD WHEREBY DISTRIBUTION COSTS ARE CLASSIFIED AS CAPACITY AND ENERGY-RELATED. HAS THE COMPANY DONE THIS ANALYSIS IN THE CURRENT RATE CASE?

A. No. This method separates distribution costs into demand and energy components based on the System load factor. As was discussed in the prior rate case, I am not aware of any electric utility using, or any regulatory commission accepting, this method to classify distribution costs.

Q. DOES THE NARUC MANUAL MENTION THIS AS A METHOD THAT SHOULD BE CONSIDERED WHEN CLASSIFYING DISTRIBUTION COSTS?

A. No. Specifically, at Chapter 6, page 89 of the manual, NARUC states:

> To ensure that (distribution) costs are properly allocated, the analyst must first classify each account as demand-related, customer-related or a combination of both.
>
> As indicated in Chapter 4, all costs of service can be identified as energy-related, demand-related or customer-related. Because there is no energy component of distribution-related costs, we need consider only the demand and customer components.

Page 90 of the NARUC manual goes on to say:

> Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

8. Percent of Customers Served by Three-Phase Primary versus Single-Phase Primary Distribution Lines

Q. PLEASE DESCRIBE THE DIFFERENCE BETWEEN SINGLE-PHASE AND MULTI-PHASE 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 the data in the Company's Geographic Information System, the Company's Distribution staff determined 73.1 percent of Residential customers receive service off the single-phase primary distribution system. Table 17 also shows that significantly fewer C&I customers receive service from the single-phase primary distribution system.

Table 17

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

NSPM – Minnesota Electric Jurisdiction

Primary Distribution Line Serving the Customer Premise	Customer Class			
	Residential Customers	C&I Non-Demand	C&I Demand	Lighting Customers
Single-Phase	72.7%	41.4%	17.0%	53.6%
Multi-Phase	27.3%	58.6%	83.0%	46.4%
Total	100.0%	100.0%	100.0%	100.0%

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

A. Yes. We continue to separate distribution lines into capacity and customer components using the Company's Minimum System and Zero Intercept studies, as described in the CCOSS Guide. As we did in the last rate case, we added an additional step to split the 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___(MAP-1), Schedule 11 shows how these allocators were developed.

IV. RATE RIDER REVISIONS

A. Renewable*Connect Riders – Capacity Credit

Q. PLEASE EXPLAIN THE CAPACITY CREDIT RELATED TO RENEWABLE*CONNECT.

A. The capacity credit is a partial offset (credit) to the Renewable*Connect purchased energy costs. It is intended to reflect the capacity value that Renewable*Connect energy generation brings to the system power-supply portfolio. The amount of this "capacity-credit-based" transfer of costs from the Renewable*Connect Program into base rates (applicable to all ratepayers) is determined in general rate cases and then bundled into base rates.

Q. WHAT IMPACT DOES THE CAPACITY CREDIT HAVE ON BASE RATES?

A. The capacity credit cost from these programs results in an increase to base rates. The cost is calculated as the amount of the capacity credit per kWh multiplied by program sales. A summary of the proposed 2022 – 2024 capacity credits from these programs is shown on Exhibit___(MAP-1), Schedule 12, page 1 of 5, with the supporting calculations on pages 2-5.

Q. ARE YOU PROPOSING CHANGES TO THE RENEWABLE*CONNECT CAPACITY CREDIT RATE?

A. No, the capacity credit rate for the various Renewable*Connect programs were established in Docket Nos. E002/M-15-985 and E002/M-19-33 for the terms of the programs.

Q. HOW DID THE COMPANY CALCULATE THE CAPACITY CREDIT COST ASSOCIATED WITH THE RENEWABLE*CONNECT PROGRAMS?

A. The Renewable*Connect programs include a capacity credit component for each year of the program. We multiplied the approved capacity credit pricing component by the expected program sales to arrive at the total capacity credit expected for the program for each year of the multi-year rate plan period. The calculation is shown on Exhibit___(MAP-1), Schedule 12, pages 2-6 and results in $4,988,536 being transferred to base rates in the 2022 test year as shown on page 1. A summary of the all the capacity credit costs included in base rates for each year of the multi-year rate plan period can be found on page 1 of Exhibit___(MAP-1), Schedule 12.

B. CIP Program Rider

Q. PLEASE EXPLAIN HOW CONSERVATION IMPROVEMENT PROGRAM (CIP) EXPENSES ARE RECOVERED.

A. The total CIP expenses are recovered through two rate components. The first (and usually the largest) component is CCRC, which is bundled into base rates. The CCRC is reset in general rate case proceedings at the test year CIP expense level. The second component is the CAF. It is calculated annually to reflect the difference between total CIP program costs (as they change over time) and the most recent test year CCRC.

Q. WHAT ARE THE CURRENT CCRC AND CAF LEVELS?

A. The current CCRC is 0.3133¢ per kWh, and was established in the Company's most recent case based on the 2016 test year level of CIP expenses. The current CAF is 0.1848¢ per kWh, which became effective with Commission approval on July 19, 2019 in Docket No. E002/M-19-258.

Q. IS THE COMPANY PROPOSING TO UPDATE THE CCRC AND CAF IN THIS CASE?

A. Yes. The Company is proposing an increase in the CCRC from the current 0.3133¢ per kWh to 0.4908¢ per kWh to reflect 2022 test year CIP costs of $128,485,463. The Company is also proposing a corresponding decrease in the CAF from the current level of 0.3521¢ per kWh to 0.1746¢ per kWh. The lower CAF fully offsets the higher CCRC, resulting in a net zero change in total CIP program cost recovery from current levels. The calculation of these revised CCRC and CAF components is shown in Exhibit___(MAP-1), Schedule 13.

V. GENERAL RULES AND REGULATIONS

Q. WHAT REVISIONS ARE BEING PROPOSED IN THE COMPANY'S GENERAL RULES AND REGULATIONS PORTION OF THE TARIFF?

A. The following are the areas in the General Rules and Regulations portion of the tariff where the Company is proposing revisions. These costs have not been revised since the Company's 2010 rate case.

- Excess Footage Charges Section 5.1.A.1
- Winter Construction Charges Section 5.1.A.2

A. Excess Footage Charges—Section 5.1.A.1

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

A. There are three excess footage charges specified on Tariff Sheet No. 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 18 below.

Table 18

Excess Footage Charges (Per Foot)

Type	Present Rate	Proposed Rate
Service Line	$7.90	$12.50
Single Phase Sec or Prim	$8.00	$13.00
Three Phase Sec or Prim	$13.90	$21.00

The cost analysis supporting these increases in charges is provided on page 2 of Exhibit___(MAP-1), Schedule 14.

B. Winter Construction Charges—Section 5.1.A.2

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. 24 of the General Rules and Regulations. The Company is proposing an increase in each as shown in Table 19 below.

Table 19

Winter Construction Charges

Type	Present Rate	Proposed Rate
Thawing (Per Frost Burner)	$600.00	$685.00
Trenching (Per Foot)	$3.80	$8.90

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___(MAP-1), Schedule 14.

C. Revenue Impact of the Proposed Excess Footage and Winter Construction Rate Increases

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

A. The net annual revenue impact from the increase in these rates is $666,756 as shown on page 1 of Exhibit___(MAP-1), Schedule 14. This increase in revenues is shown with the increase in late payment charges on lines 2 and 14 of Schedules 3, 5, and 7 attached to my testimony. It is also shown on page 7, row 21 of Schedules 4, 6, and 8 attached to my testimony. The proposed increase in these charges reduces the proposed increase in retail revenues by Mr. Paluck.

VI. COMPETITIVE RESPONSE RIDER COMPLIANCE

Q. HAS THE COMPANY PERFORMED AN INCREMENTAL COST AND BENEFIT ANALYSIS FOR CUSTOMERS ON THE COMPETITIVE RESPONSE RIDER?

A. Yes, Exhibit___(MAP-1), Schedule 15 includes an incremental cost and benefit analysis in compliance with Order Point 3. C. in the Commission's Order dated July 15, 2019 in Docket No. E002/M-19-39.

Q. PLEASE SUMMARIZE THE RESULTS OF THE ANALYSIS.

A. The analysis includes the first full year of service under the Competitive Response Rider and confirms that the incremental costs are more than offset by the incremental revenues.

VII. SUMMARY AND CONCLUSION

Q. PLEASE SUMMARIZE THE CONCLUSIONS FROM YOUR TESTIMONY.

A. The purpose of a CCOSS is to provide a reasonable measure of the contribution each class makes to the Company's overall cost of service, with the ultimate goal of generating a basis from which rates can be evaluated and refined. We have modified our CCOSS methodology since the Company's most recent case based on several new or renewed studies and Commission Order. These modifications result in CCOSSs that:

- Properly recognize that our investments in baseload generation facilities provide value to all customers, particularly our energy-intensive users;
- Accurately reflect the value of our investments in peaking capacity, transmission and distribution facilities used to meet system peak requirements;
- Recognize the differing impact that seasonal and time usage patterns can have on the cost of service; and
- Recognize that a portion of distribution costs are incurred to simply connect customers to the system and therefore should be allocated to customer class based on the number of customers.

Given the refinements to the CCOSS over time, resulting in appropriate and improved allocations to previous years, the Company has turned to structural enhancements in this case. Our CCOSS model is now more robust and transparent. Therefore, the Company's CCOSSs are appropriate rate making tools in this case.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications and Experience
Michael A. Peppin

OVERVIEW

My qualifications include more than 40 years of experience with Xcel Energy and its predecessors in the areas of market research and cost-of-service analysis. My current responsibilities at Xcel Energy include Class Cost of Service Studies conducted in support of the Company's rate cases and providing pricing function support and other related analyses for the utility operating subsidiaries of Xcel Energy. I have served as a class cost of service witness in multiple rate cases in Minnesota, South Dakota, North Dakota and Texas.

PROFESSIONAL EXPERIENCE

Principal Pricing Analyst; Xcel Energy, NSPM	2006 – Present
Senior Market Research Manager; Cargill Corporation	2005 – 2006
Manager, Market Research; Seren Innovations, a subsidiary of NSP	2000 – 2005
Manager, Product Development Support; NSP Electric Utility	1998 – 2000
Manager, Market Research; NSP Electric Utility	1990 – 1998
Manager, Market Research; NSP Gas Utility	1986 – 1990
Principal Market Research Analyst; NSP Electric Utility	1979 – 1986

EDUCATIONAL BACKGROUND

University on Minnesota; MBA Marketing and Statistics	1980
University of Minnesota; BA Psychology and Statistics	1978

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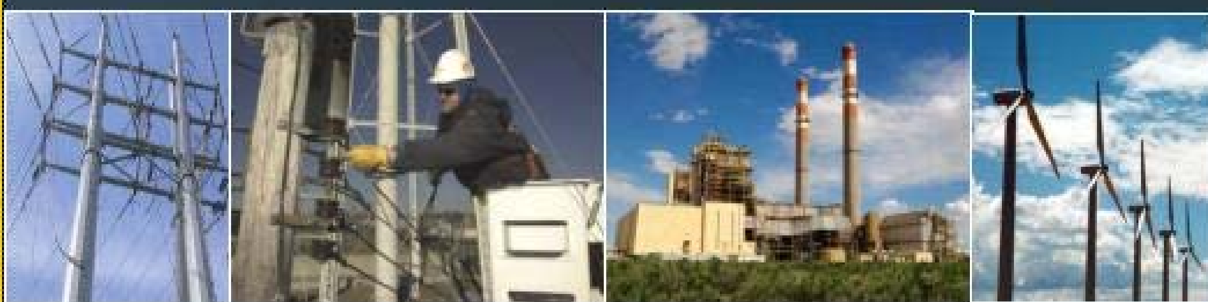

Guide to the Electric Class Cost of Service Study (CCOSS)
Northern States Power Company

I. Overview

Simply stated, the purpose of the Northern States Power Company (NSP) electric Class Cost of Service (CCOSS) is to allocate ***joint*** (e.g.) and ***common*** costs to the designated "classes" of service such as Residential, Non-Demand C&I, and Demand C&I. For example, generation capacity costs are "joint" between time periods and overhead costs such as management, are "common" to multiple functions, such as distribution, transmission, and generation. The CCOSS also assigns ***direct*** costs (e.g. a dedicated service extensions or dedicated substations), that may be associated with providing service to a particular customer from a specific class of service. The objective of the CCOSS is to make these cost ***allocations*** and ***assignments*** based on identifiable service requirements (e.g. kWh energy requirements and kW capacity requirements), which are the drivers of the costs.

The two basic types of costs are; (1) capital costs associated with investment in generation, transmission, and distribution facilities and (2) on-going expenses such as fuel used to produce the energy, labor costs, and numerous other operating expenses. The end result is an allocation of the total utility costs (i.e. the revenue requirements) to customer classes according to each class' share of the capacity, energy, and customer service requirements.

II. Major Steps of the Class Cost of Service Study

A class cost of service study begins with a detailed documentation of the numerous budgetary elements of the total revenue requirement for the jurisdiction in question. The detailed jurisdictional revenue requirements are the data inputs to the CCOSS. At a high level, the CCOSS process consists of the following three (3) basic steps:

1. Functionalization – The identification of each cost element as one of the basic utility service "functions" (e.g. generation, transmission, distribution, and customer).
2. Classification – The classification of the functionalized costs based on the billing component/determinant that each is associated with (e.g. kWs of capacity, kWhs of energy, or number of customers).
3. Allocation – The allocation of the functionalized and classified costs to customer classes, based on each class' respective service requirements (e.g. kWs of capacity, kWhs of energy, and the number of customers, expressed in terms of a percentage of the total jurisdiction requirement).

III. Step 1: Functionalization

Functionalization is the process of associating each of the numerous detailed elements of the total revenue requirement with functions (and sometimes sub-functions) of the electric utility system. Costs must be first functionalized because each class' service requirement tends to have different relative impacts on each service function. As such, it is necessary to develop separate sub-parts of the total revenue requirement for each function (and sometimes sub-function). The four (4) basic functions and the associated sub-functions are shown in the table below:

Function	**FERC Accounts**	**Sub-Function**	**Description**
Generation	120, 310-346, 500-557	"Energy-related"	Includes the fixed costs of generation plant investment and purchase capacity costs, which have been stratified as "energy-related."
		Summer "capacity-related."	Includes the fixed costs of generation plant investment and purchase capacity costs stratified as "capacity-related" and which are associated with the system summer peak load requirements.
		Winter "capacity-related."	Includes the fixed costs of generation plant investment and purchase capacity costs stratified as "capacity-related" and which are associated with the system winter peak load requirements.
		On-Peak Energy	Includes costs for fuel and purchases of energy for on-peak hours.
		Off-Peak Energy	Includes costs for the fuel and purchases of energy for off-peak hours.
Transmission	350-359, 560-579	None	Includes costs of transmission lines used to transport power from its origin generation stations or delivery points to the high voltage side of the distribution substations.
Distribution	360-368, 580-598	Distribution Substations	Includes costs of the facilities (e.g. transformers and switch gear) between the transmission and distribution systems.
		Primary Distribution System "Capacity."	Includes costs of the "capacity" portion (as distinguished from the "customer" portion) of primary voltage conductors, transformers and related facilities.
		Secondary Distribution System "Capacity."	Includes costs of the "capacity" portion (as distinguished from the "customer" portion) of secondary voltage conductors, transformers, customer services and related facilities.
Customer	360-369, 580-598, 901-916	"Customer" portion of the Primary and Secondary Systems	Includes costs for the "customer" portion of primary and secondary conductors, transformers, customer service drops, related facilities and the costs of metering.
		Energy Services	Includes costs for meter reading, billing, customer service and information, and back office support.

A. Generation Cost Stratification

Stratification is the term used to identify the part of the CCOSS process used to separate or "stratify" fixed generation costs into the necessary "capacity-related" and "energy-related" sub-functions. The "capacity-related" portion of the fixed costs of owned generation is based on the percent of total fixed costs of each generation type that is equivalent to the cost of a comparable peaking plant (the generation source with the lowest capital cost). The percent of total generation costs that exceeds the cost of a comparable peaking plant are sub-functionalized as "energy-related." This second portion of the fixed generation costs is "energy-related" because these costs are in excess of the "capacity-related" portion and as such were not incurred to obtain capacity but rather were incurred to obtain the lower cost energy that such plants can produce.

For example, the plant stratification analysis used in the current rate case is shown in the table below. It compares the current dollar replacement costs of each plant type, to develop stratification percentages.

Plant Type	$/kW	Capacity Ratio	Capacity %	Energy %
Peaking	$1,026	$1,026 / $1,026	100.0%	0.0%
Nuclear	$5,109	$1,026 / $5,109	20.1%	79.9%
Fossil	$2,444	$1,026 / $2,444	42.0%	58.0%
Combined Cycle	$1.514	$1,026 / $1.514	67.8%	32.2%
Hydro	$5,756	$1,026 / $5,756	17.8%	82.2%
Wind	$11,262	$1,026 / $11,262	9.1%	90.9%

This process of "stratifying" the revenue requirements of the generation plant is accomplished by applying these stratification percentages to each component of the revenue requirements (e.g. plant investment, accumulated depreciation, deferred income taxes, construction work in progress (CWIP), etc.), for each generation plant type.

IV. Step 2: Cost Classification

The second step in the CCOSS process is to classify the functionalized costs as being associated with a measurable customer service requirement which gives rise to the costs. The three (3) principle service requirements or billing components are:

1. Demand – Costs that are driven by customers' maximum kilowatt (kW) demand.
2. Energy – Costs that are driven by customers' energy or kilowatt-hours (kWh) requirements.
3. Customer – Costs that are related to the number of customers served.

The table below shows how each of the functional and sub-functional costs was classified:

Function/Sub-Function	**Cost Classification**		
	Demand	**Energy**	**Customer**
Summer Capacity-Related Fixed Generation	X		
Winter Capacity-Related Fixed Generation	X		
Energy-Related Fixed Generation		X	
Off-Peak Energy (Fuel and Purchased Energy)		X	
On-Peak Energy (Fuel and Purchased Energy)		X	
Transmission	X		
Distribution Substations	X		
Primary Transformers	X		
Primary Lines	X		X
Secondary Lines	X		X
Secondary Transformers	X		X
Service Drops	X		X
Metering			X
Customer Services			X

As shown in the table above, primary lines, secondary lines, secondary transformers, and service drops are classified as both "demand" and "customer" related costs. Costs of these sub-functions are driven by **both** the number of customers on the distribution system and the capacity requirements they place on the system. Two methods that are mentioned in the NARUC manual for performing this cost separation are the Minimum Distribution System method and the Minimum/Zero Intercept method.

The Minimum Distribution System method involves comparing the cost of the minimum size of each type of facility used, to the cost of the actual sized facilities installed. The cost of the minimum size facilities determines the "customer" component of total costs, and the "capacity" cost component is the difference between total installed cost and the minimum sized cost.

The Minimum/Zero Intercept method requires significantly more data and analysis than the Minimum Distribution System method. The Minimum/Zero Intercept method requires the analyst to develop installed per unit costs for the most common property unit configurations. Next, the maximum capacity rating (Ampacity for conductors and kVa for transformers) must be determined. Once the above data has been acquired, the statistical analysis technique called linear regression is applied to 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. The zero intercept cost for a given property unit determines the "customer" component of total costs, and the "capacity" cost component is the difference between total installed cost and the zero intercept cost.

The Company completed both minimum system and zero intercept studies for all property units except distribution services. Detailed property records on the configuration or footage of distribution service drops are not available. As a result, the Company was not able to conduct a detailed minimum system or zero intercept study for classifying the cost of service drops. As a substitute, a simplified minimum system analysis was conducted.

For each property unit, the table below shows the percent of costs that were classified as customer-related using the Minimum/Zero Intercept method compared to the Minimum Distribution System method. As shown below, for 4 of the 6 property units the Minimum/Zero Intercept method provides a lower customer component, while 2 of the 6 have a lower customer component using the Minimum Distribution System method.

	% of Costs Classified as "Customer" Related	
Equipment Type	**Minimum/Zero Intercept Method**	**Minimum Distribution System Method**
Overhead Lines Primary	35.3%	63.7%
Overhead Lines Secondary	78.6%	99.2%
Overhead Transformers	75.3%	77.4%
Underground Lines Primary	53.0%	62.3%
Underground Lines Secondary	59.6%	100%
Underground Transformers	87.0%	51.6%

In applying the results of the zero intercept and minimum system studies to the proposed CCOSS, the Company used a hybrid of the two methods, such that the Company used the method that provided the lower customer component as shown in the table below.

Property Unit	**% Customer Related**	**% Capacity Related**
Overhead Lines Primary (used Zero Intercept Result)	35.3%	64.7%
Overhead Lines Secondary (used Zero Intercept Result)	78.6%	21.4%
Underground Lines Primary (used Zero Intercept Result)	53.0%	47.0%
Underground Lines Secondary (used Zero Intercept Result)	59.6%	40.7%
Weighted Average for Overhead & Underground Transformers (used Zero Intercept for OH Transformers; used Minimum System for UG Transformers)	63.3%	36.7%

V. Step 3: Cost Allocation to Customer Class (Assignment of Costs to Customer Classes)

The third step in the CCOSS process is allocation, which is the process of assigning (allocating or directly assigning) functionalized and classified costs to customer classes. Generally, cost assignment occurs in one of two ways:

- Direct Assignment - A small but sometimes important portion of costs can be directly assigned to a specific customer of a particular customer class, because these costs can be exclusively identified as providing service to a particular customer. Examples of costs that are directly assigned include:
  - Customer-dedicated transmission radial lines or dedicated distribution substations; and
  - Street lighting facility costs.
- Allocation - Most electric utility costs are incurred in common or jointly in providing service to all or most customers and classes. Therefore, allocation methods have to be developed for each functionalized and classified cost component. The allocation method is based on the particular measures of service that is indicative of what drives the costs.
  - Class allocators (sometimes called allocation strings) are simply a "string" of class percentages that sum to 100%.
  - There are 2 types of allocators:
    - External Allocators –These are the more interesting allocators that are based on data from outside the CCOSS model (e.g. load research data, metering and customer service-related cost ratios). In general, there are three types of external allocators:
      - Capacity –related (sometimes referred to as Demand) allocators such as:
        - System coincident peak (CP) responsibility or class contribution to system peak (1CP, 4CP or 12CP);
        - Class peak or non-coincident peak; and
        - Individual customer maximum demands.
      - Energy-related allocators such as:
        - kWh at the customer (kWh sales);
        - kWh at the generator (kWh sales plus losses); and
        - kWh energy, weighted by the variable cost of the energy in the hour it is used.
      - Customer-related allocators
        - Number of customers; and
        - Weighted number of customers, where the weights are based on cost of meters, billing, meter-reading, etc.

      Details on the external allocators used in the CCOSS model are shown in Appendix 2.

    - Internal Allocators – These are allocators based on combinations of costs already allocated to the classes using external allocators. These internal allocators are used to assign certain costs, which are most appropriately associated with and assigned to classes by some combination of other primary service requirements, such as kWs demand, kWhs of energy or the number of customers. Examples of internal allocators include:

- Production, transmission and distribution plant investment – Labeled "PTD" in the CCOSS model.
- Distribution O&M expenses without supervision and miscellaneous expenses – Labeled "OXDTS" in the CCOSS model.

Details on the development of the internal allocators used in the CCOSS model are shown in Appendix 3.

VI. Customer Class Definitions

Ideally, there would be no customer class groupings and cost allocation would reflect the unique costs of each individual customer. Because this is not possible, it is necessary to develop a cost study process that identifies costs of service for groups of customers ("classes") where the customers of the class have similar cost/service characteristics. The basic classes of service employed in the Company's CCOSS are the following:

1. Residential;
2. Non-Demand Metered Commercial;
3. Demand Metered Commercial & Industrial; and
4. Street & Outdoor Lighting.

Also, because of the significantly different distribution-functional requirements of customers within the Demand Metered C&I class, the Company's CCOSS also identifies the cost differences associated with the following distribution-function requirements within this class based on the voltage they are served at:

1. Secondary;
2. Primary;
3. Transmission Transformed; and
4. Transmission.

More detail on customer class definitions is shown in Appendix 1.

VII. Organization of the CCOSS Model

The CCOSS model consists of numerous worksheets which show costs by customer class in Total (as shown on the worksheet tab labeled "RR-TOT") and at the following more detailed levels including Billing Unit, Function and Sub-function as shown below (the label of the worksheet tab in shown in parenthesis below):

1. Billing Unit:

    a. Customer (RR-Cus)
    b. Demand (RR-Dmd)
    c. Energy (RR-Ene)

2. Function and Associated Sub-Function:

   a. Energy (RR-Ene)
      a) On-Peak Energy (RR-On)
      b) Off-Peak Energy (RR-Off)

   b. Generation (RR-Gen_Dmd): Sub-functions include:
      a) Summer Capacity-Related Plant (RR-Summ)
      b) Winter Capacity-Related Plant (RR-Wint)
      c) Energy-Related Plant (RR-Base)

   c. Transmission (RR-Transco)

   d. Distribution (RR-Disco): Sub-functions include:
      a) Distribution Substations (RR-Psub)
      b) Primary Voltage (RR-Prim)
      c) Secondary Voltage (RR-Sec)

   e. Customer (RR-Cus): Sub-functions include:
      a) Service Drops (RR-Svc_Drop)
      b) Energy Services (RR-En_Svc)

In the CCOSS spreadsheet, there is a separate worksheet tab for each of the above billing units, functions, and sub-functions. This multi-level breakdown of costs is useful for designing rates as well as for determining class revenue responsibilities.

VIII. CCOSS Calculations

Listed below are important calculations that are part of the CCOSS model. These calculations occur at the "TOT" layer of the CCOSS as well as each of the "sub-layers" for each billing component, function and sub-function. Showing results at the more detailed billing component, function and sub-function levels is important for rate design purposes, as well as other analyses such as the development of voltage discounts.

A. Rate Base Calculation

Rate Base = Original Plant in Service – Accum Depr – Accum Defer Inc Tax+ CWIP + Other Additions

The above rate base calculation occurs on "TOT" layer as well as each function/sub-function layer.

B. Revenue Requirements Calculation (Class Cost Responsibility)

The Revenue Requirements Calculation (sometimes referred to as the "Backwards Revenue Requirement Calculation) is used to calculate "cost" responsibility for each customer class. This has to be done within the CCOSS model because the JCOSS model does it only at the total jurisdiction level, not by class. The class "cost" responsibility is based on the same return on rate base for each class that is equal to the overall proposed rate of return. In other words, class revenues requirements are calculated to provide the same return on rate base for each customer class. This calculation occurs on the "TOT" layer as well as for each function, sub-function, and billing component after all expenses and rate base items have been allocated. As such, class cost responsibility is available for each function, sub-function, and billing component. This analysis serves a starting point for rate design. The formula is shown below:

Retail Revenue Requirement = Expenses (less off-setting credits from Other Operating Revenues)
+
(((% Return on Invest x Rate Base) - AFUDC - Fed Credits) x 1 / (1 - Fed T) - Fed Section 199 Deduc x Fed T/(1-Fed T) - State Credits) x 1 / (1 - State T)
+
(Tax Additions – Tax Deductions) x Tax Rate / (1-Tax Rate)

Where:

Tax Rate = 1 – (1- State T)x (1-Fed T)

Expenses = O&M + Book Depreciation + Real Estate & Property Tax + Payroll Tax + Net Investment Tax Credit – Other Retail Revenue – Other Oper. Revenue

Tax Additions = Book Depreciation + Deferred Inc Tax + Net Inv Tax Credit + Other Misc Expenses.

Tax Deductions = Tax Depreciation + Interest Expense + Other Tax Timing Diff

C. Total Return and Return on Rate Base (Based on Class Revenue Responsibility)

After rates have been designed and each class' "revenue" responsibility has been determined, the model calculates total return and return on rate base using the following formulas. These calculations are performed at both present and proposed rate levels.

Total $ Return = Revenue – O&M Expenses – Book Depr.
– Real Estate & Property Taxes – Provision for Deferred Inc Taxes – Inv. Tax Credits
– State & Federal Income Taxes + AFUDC

Percent Return on Rate Base = Total $ Return / $ Rate Base

After rates have been designed, the return on rate base is typically different for each customer class. In other words, the resulting class "revenue" responsibility differs from class **"cost"** responsibility.

XI. CCOSS Output

The filed output of the CCOSS model includes the "TOT" worksheet layer of the much larger model. The important output from the functional, sub-functional and billing component layers is presented on pages 2 and 3 of this "TOT" layer. The following table lists what is shown on each CCOSS page when printed.

Final CCOSS Printout "TOT" Worksheet

CCOSS Section	Page Number	Results Detail	Line Numbers
Results Summary	1	Rate Base Summary	1-21
		Income Statement Summary	22-31
	2	**Proposed Cost** Responsibility at Equal ROR (the cost of service) compared to **Present** Rate **Revenue** Responsibility	1-51
	3	**Proposed Cost** Responsibility at Equal ROR (the cost of service) compared to **Proposed** Rate **Revenue** Responsibility	1-54
Rate Base Detail	4	Original Plant in Service	1-50
	5	MINUS Accumulated Depreciation	1-29
		MINUS Accumulated Deferred Income Tax	30-57
	6	PLUS Construction Work in Progress & Other Additions	1-36
		EQUALS Total Rate Base & Common Rate Base	37-38
Income Statement Detail	7	Present and Proposed Revenues	1-26
		MINUS O&M Expenses part 1	27-41
	8	MINUS O&M Expenses part 2	1-34
	9	MINUS Book Depreciation	1-24
		MINUS Real Estate & Property Taxes, Other Taxes	25-51
	10	MINUS Provision for Deferred Income Tax	1-27
		MINUS Investment Tax Credit; Total Operating Expense	28-52
		EQUALS Present and Proposed Operating Income Before Income Taxes	53A 53B
	11 (Income Tax Calcs.)	Tax Additions	31-36
		MINUS Tax Deductions	1-30
		EQUALS Total Income Tax Adjustments	37
		Present and Proposed Taxable Net Income	38A 38B
		Present and Proposed State and Federal Income Taxes	39A 39B
		Present and Proposed Preliminary Return	40A 40B
		AFUDC (from page 12)	41
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Guide to the Class Cost of Service Study
CCOSS Customer Classes vs. Tariff Cross Reference

	Customer Class	Rate Codes	kW Size	Voltage Specifications	Costs Not Assigned	Why Costs Not Assigned
1	Residential	A00, A01, A02, A03, A04, A05 (if residential), A06 (if residential), A08, A72, A74, A80, A81, A82, A83			• Costs directly attributed to and directly assigned to Street Lighting customers. • Directly assigned costs of specific Transmission Radial Lines and Distribution Substations that solely serve other customer classes.	The listed facilities and their associated costs are not used to provide service to these customers.
2	C&I Non Demand Metered	A05 (if C&I), A06 (if C&I), A09, A10, A11, A12, A13, A16, A18, A22, A40, A42,	< 25 kW		• Costs directly attributed to and directly assigned to Street Lighting customers. • Directly assigned costs of specific Transmission Radial Lines and Distribution Substations that solely serve other customer classes.	The listed facilities and their associated costs are not used to provide service to these customers.
3	C&I Secondary Voltage	A14, A15, A17, A19, A23, A24, A27, A29, A41, A62, A63, A87, A88, A89, A90	> 25 kW	Secondary	• Costs directly attributed to and directly assigned to Street Lighting customers. • Directly assigned costs of specific Transmission Radial Lines and Distribution Substations that solely serve other customer classes. • Costs of Underground ("UG") services. C&I customers pay for their own UG services.	The listed facilities and their associated costs are not used to provide service to these customers.
4	C&I Primary Voltage	A14, A15, A17, A19, A23, A24, A27, A29, A41, A62, A63	> 25 kW	Primary	• Costs directly attributed to and directly assigned to Street Lighting customers. • Directly assigned costs of specific Transmission Radial Lines and Distribution Substations that solely serve other customer classes. • Costs of Secondary Voltage Overhead and Underground Lines that have been classified as either "Customer" or "Capacity" related. • Costs of Secondary Voltage Transformers that have been classified as either "Customer" or "Capacity" related. • Costs of Service Lines that have been classified as either "Customer" or "Capacity" related.	The listed facilities and their associated costs are not used to provide service to these customers.

Guide to the Class Cost of Service Study
CCOSS Customer Classes vs. Tariff Cross Reference

	Customer Class	Rate Codes	kW Size	Voltage Specifications	Costs Not Assigned	Why Costs Not Assigned
5	C&I Transmission Transformed Voltage	A14, A15, A17, A19, A23, A24, A27, A29, A41, A62, A63	> 25 kW	Transmission Transformed	• Costs directly attributed to and directly assigned to Street Lighting customers. • Directly assigned costs of specific Transmission Radial Lines and Distribution Substations that solely serve other customer classes. • Costs of Primary Voltage Transformers. • Costs of Primary Voltage Overhead and Underground Lines that have been classified as either “Customer” or “Capacity” related. • Costs of Secondary Voltage Overhead and Underground Lines that have been classified as either “Customer” or “Capacity” related. • Costs of Secondary Voltage Transformers that have been classified as either “Customer” or “Capacity” related. • Costs of Service Lines that have been classified as either “Customer” or “Capacity” related.	The listed facilities and their associated costs are not used to provide service to these customers.
6	C&I Transmission Voltage	A14, A15, A17, A19, A23, A24, A27, A29, A41, A62, A63	> 25 kW	Transmission	• Costs directly attributed to and directly assigned to Street Lighting customers. • Directly assigned costs of specific Transmission Radial Lines. • Costs of Distribution Substations. • Costs of Primary Voltage Transformers. • Costs of Primary Voltage Overhead and Underground Lines that have been classified as either “Customer” or “Capacity” related. • Costs of Secondary Voltage Overhead and Underground Lines that have been classified as either “Customer” or “Capacity” related. • Costs of Secondary Voltage Transformers that have been classified as either “Customer” or “Capacity” related. • Costs of Service Lines that have been classified as either “Customer” or “Capacity” related.	The listed facilities and their associated costs are not used to provide service to these customers.
7	Outdoor Lighting	A07, A30, A32, A34, A35, A37			• Directly assigned costs of specific Transmission Radial Lines and Distribution Substations that solely serve other customer classes.	The listed facilities and their associated costs are not used to provide service to these customers.

Guide to the Class Cost of Service Study
EXTERNAL ALLOCATORS: DESCRIPTIONS AND APPLICATIONS

Code	Allocator for:	Description	Data Source(s)	Derivation	Allocator Rationale
C11	Connection charge revenues	Average monthly customers	- 2021 Customer forecast for TY2022	Forecasted annual bills / 12	Connection charge revenue isn't specifically included in the NARUC manual. New customer connections, by class, follow the pattern of existing customers. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
C11WA	Customer accounting costs	Weighted customer accounting costs	- 2021 Customer forecast for TY2022 and - 2021 customer accounting weighting factors	C11 X C11WAF	On page 103, the NARUC manually says customer accounting costs are classified as customer-related, which matches Xcel's approach. As for allocating costs to class, the chosen allocator recognizes that classes with larger customers require more complicated tracking per customer. Thus, such classes should get heavier weights. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
C12WM	Meter costs	Weighted meter investment	- 2021 meter, CT and VT model inventory by customer class - 2021 meter, CT and VT replacement costs	C12 X C12WMF	On page 96, the NARUC manual notes that meters are normally classified as customer-related. And on page 98, the manual supports the idea of weighting classes differently to reflect differences in capital investment levels. Xcel's allocator follows both suggestions. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
C61PS	The "customer" (minimum system) portion of multi-phase primary distribution line costs	Average monthly customers served at primary or secondary voltage	- Customer 2021 forecast for TY2022 - 2021 Minimum System and Zero Intercept studies	C11 less transmission transformed and transmission voltage customers	On page 87, the NARUC manual only discusses overhead and underground lines in general, rather than primary, multi-phase lines in particular. It suggests a mixed classification of demand- and customer-related, based on a minimum system study. Xcel follows that approach. This allocator only addresses customer-based costs. It reflects both secondary and primary voltage customers, since both make use of primary lines. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
C61PS1Ph	The "customer" (minimum system) portion of single phase primary distribution line costs	Average monthly customers that are served by single phase primary distribution facilities	- Customer forecast for TY2022 and 2021 - Minimum System and Zero Intercept studies - GIS data that shows the percent of customers in each class that receive service from the single phase primary distribution system	C61PS multiplied by the percent of customers in each class that receive service from the single phase primary distribution system	On page 87, the NARUC manual only discusses overhead and underground lines in general, rather than primary, single-phase lines in particular. It suggests a mixed classification of demand- and customer-related, based on a minimum system study. Xcel follows that approach. This allocator only addresses customer-based costs. It reflects both secondary and primary voltage customers, since both make use of primary lines. But it only applies to those served by a single phase. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.

Guide to the Class Cost of Service Study
EXTERNAL ALLOCATORS: DESCRIPTIONS AND APPLICATIONS

Code	Allocator for:	Description	Data Source(s)	Derivation	Allocator Rationale
C62NL	The customer portion of Company owned service costs.	Adjusted average monthly secondary voltage customers	- Customer forecast for TY2022 - 2021 Minimum System and Zero Intercept studies	C62Sec less street lighting and C&I underground customers	On page 87, the NARUC manual discusses services, suggesting just a customer-related classification. Xcel chose instead to extend the minimum system approach to service lines, thus recognizing that a service wire has a capacity aspect, as well as the ability to deliver a minimum electrical connectivity. This allocator only addresses customer-based costs. It excludes lighting customers, since they don't have service wires. And it excludes C&I underground customers, since they own their service wire. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
C62Sec	The customer portion of secondary distribution line costs	Average monthly customers served at secondary voltage	- Customer forecast for TY2022 - 2021 Minimum System and Zero Intercept studies	C61PS less primary voltage customers	On page 87, the NARUC manual only discusses overhead and underground lines in general, rather than secondary lines in particular. It suggests a mixed classification of demand- and customer-related, based on a minimum system study. Xcel follows that approach. This allocator only addresses customer-based costs. It reflects all secondary voltage customers. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.

Guide to the Class Cost of Service Study
EXTERNAL ALLOCATORS: DESCRIPTIONS AND APPLICATIONS

Code	Allocator for	Description	Data Sources	Derivation	Allocator Rationale
D10S	Capacity-related generation costs and all transmission costs	Class contribution to System Peaks at MISO's peak hour for Local Resource Zone 1 (LRZ-1)	- 8760 load research data by class for the years 2015-2019 synched to the 2021 kWh Sales Forecast for TY2022	Since the MISO LRZ-1 peak hour for the test year is not available, used hourly class loads that are in the same hours as the top 6 NSP System loads for the 2022 test year. Loads in the top 6 hours are used because based on 12 years of historical data, one of the 6 highest NSP System load hours is always in the same hour as the MISO LRZ-1 peak hour	Pages 39 through 63 of the NARUC manual discuss numerous methods for allocating generation capital costs to class. And pages 75 through 83 of the manual discuss many of the same methods for allocating transmission line costs. The Company employs a different approach that nonetheless reflects many of the underlying issues in the manual. This approach recognizes that a portion of a utility's generation assets, as well as all of their transmission assets, are built for the purpose of meeting peak load. And this allocator is applied to those costs. This allocator previously reflected the utility's own annual, coincident peak – i.e., a 1CP approach. But because the company has become so fully integrated with MISO, and because MISO basically dispatches the company's power plants, a MISO-coincident peak is now used. A significant portion of the utility's generation investments is made primarily to facilitate the consumption of lower-cost fuel (rather than to meet peak demand). Those costs are allocated to class based on an energy allocator, as discussed for E8760. Such costs are still classified as demand-related. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
D60Sub	Distribution substation costs	Class-coincident peak less transmission-level demand	- 8760 load research data by class for the years 2015-2019 synched to the 2021 kWh Sales Forecast for TY2022		On pages 77 through 83, the NARUC manual discusses several possible class allocation methods for transmission plant, all related to some form of peak demand (other than a direct assignment approach). If a single season (in Xcel Energy's case, summer) clearly has the largest peak, then a 1CP method seems to be the most appropriate. And the Company does use 1CP. In particular, this allocator represents the annual coincident peak demand of every customer class except those served at transmission voltage (since they don't make use of step-down substations). The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.

Guide to the Class Cost of Service Study
EXTERNAL ALLOCATORS: DESCRIPTIONS AND APPLICATIONS

Code	Allocator for	Description	Data Sources	Derivation	Allocator Rationale
D61PS	The capacity portion of multi-phase primary voltage distribution line costs.	Class-coincident peak for primary and secondary voltage customers	- 8760 load research data by class for the years 2015-2019 synched to the 2021 kWh Sales Forecast for TY2022 - 2021 Minimum System and Zero Intercept studies	D60Sub less Transmission Transformed customer demands, less customer demands served by minimum distribution system and with reduced Residential Space Heating demands to reflect their summer peak is less than their winter peak	On page 87, the NARUC manual only discusses overhead and underground lines in general, rather than primary, multi-phase lines in particular. It suggests a mixed classification of demand- and customer-related, based on a minimum system study. Xcel follows that approach. This allocator only addresses demand-based costs. It reflects the class-coincident peak for both secondary and primary voltage customers, since both make use of primary lines. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
D61PS1Ph	The capacity portion of single phase primary distribution line costs	Class-coincident peak for primary and secondary voltage customers for customers that use the single phase primary distribution system	- 8760 load research data by class for the years 2015-2019 synched to the 2021 kWh Sales Forecast for TY2022 - 2021 Minimum System and Zero Intercept studies - GIS data that shows the percent of customers in each class that receive service from the single phase primary distribution system	D61PS multiplied by the percent of customers in each class that receive service from the single phase primary distribution system.	On page 87, the NARUC manual only discusses overhead and underground lines in general, rather than primary, single-phase lines in particular. It suggests a mixed classification of demand- and customer-related, based on a minimum system study. Xcel follows that approach. This allocator only addresses demand-based costs. It reflects the class-coincident peak for both secondary and primary voltage customers, since both make use of primary lines. But it only applies to those served by a single phase. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
D62NLL	The capacity portion of company owned service line costs	Secondary voltage demand less lighting	- Individual customer maximum demands from load research for non-demand billed customers and 2019 billing data for demand billed customers - 2021 Minimum system and Zero Intercept studies.	Non-coincident (or "customer peak") demand for secondary voltage customers, less the following: street lighting, area lighting and C&I customers served underground	On page 87, the NARUC manual discusses services, suggesting just a customer-related classification. Xcel chose instead to extend the minimum system approach to service lines, thus recognizing that a service wire has a capacity aspect, as well as the ability to deliver a minimum electrical connectivity. This allocator only addresses demand-based costs. It excludes lighting customers, since they don't have service wires. And it excludes C&I underground service customers, since they own their service wire. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.

Guide to the Class Cost of Service Study
EXTERNAL ALLOCATORS: DESCRIPTIONS AND APPLICATIONS

Code	Allocator for	Description	Data Sources	Derivation	Allocator Rationale
D62SecL	The capacity portion of secondary distribution line costs	Average of class-coincident peak, secondary voltage percentages and non-coincident secondary voltage percentages	- TY2022 load research class coincident demands - 2021 Minimum system and Zero Intercept studies - Individual customer maximum demands from load research for non-demand billed customers and billing data for demand billed customers.	First define D62Sec as equal to D61PS, less primary customers. Then for each secondary class, D62SecL equals the average of D62Sec percent and non-coincident (or "customer peak"), secondary voltage percent.	On page 87, the NARUC manual discusses only overhead and underground lines in general, rather than secondary lines in particular. It suggests a mixed classification of demand- and customer-related, based on a minimum system study. Xcel follows that approach. This allocator only addresses demand-based costs. It reflects all secondary voltage customers. These capacity costs are driven by a 50/50 blend of class coincident peak demand and individual customer maximum (non-coincident) demand, less minimum system requirements. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
E8760	Fuel, purchased energy and energy-related fixed generation costs.	Class hourly energy (MWH) requirements weighted to reflect higher on-peak fuel costs	- 8760 load research data by class for the years 2015-2019 synched to the 2021 kWh Sales Forecast for TY2022 - Hourly marginal energy costs for the 2021 test year.	The hourly on-peak sales each class weighted by the hourly marginal energy cost.	On page 64, the NARUC manual notes that fuel costs are almost always classified as energy-related. And some form of time differentiation, such as on-peak vs. off-peak, is most appropriate. Xcel Energy previously used such an on-peak / off-peak approach. Then the Company migrated to a more precise approach that properly weights the marginal energy cost for each of the 8,760 hours in a standard year, along with class consumption during each hour. This allocator is applied to all fuel cost items, including purchased energy. Those costs are classified as energy-related. And as is explained in more detail for the D10S allocator, this allocator is also applied to the fuel-related portions of generation equipment. Those costs are classified as demand-related. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
E99XCIP	CIP O&M Expenses	TY2022 sales forecast by customer class Less the TY2022 sales forecast for CIP exempt customers	2021 kWh Sales Forecast for TY2022		Programs such as CIP were not anticipated by the NARUC manual. This allocator is simply based on sales. But since it applies to CIP program costs, it excludes sales from CIP-exempt customers. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.

Guide to the Class Cost of Service Study
INTERNAL ALLOCATORS: DESCRIPTIONS AND APPLICATIONS

Internal Allocators are those that are determined from data generated within the Class Cost of Service Study (CCOSS). Below is a list of internal allocators that are used within the CCOSS.

The Order in rate case Docket No. E002/GR-13-868 required the following CCOSS compliance item:

> In its next rate case the Company's class-cost-of-service study shall include an explanatory filing identifying and describing each allocation method used in the study and detailing the reasons for concluding that each allocation method is appropriate and superior to other allocation methods considered by the Company, whether those methods are based on the Manual of the National Association of Regulatory Utility Commissioners or the Company's specific system requirements, its experience, and its engineering and operating characteristics. The Company shall also explain its reasoning in cases in which it did not consider alternative methods of allocation or classification.

To comply with this requirement, Schedule 2, Appendix 2, provided detailed comments about the appropriateness of all the external allocators. However, the internal allocators are simply derived by summing up multiple external allocators – in some cases, a few dozen. If the external allocators are fitting, then the internal allocators should also be fitting.

Code	Allocator for:	Description	Allocator Justification
C11P10	Expenses and labor related to customer assistance and instructional advertising	This allocator is the average of the Customer-related C11 allocator and the Production Plant investment P10 allocator.	Customer assistance and advertising expenses are driven by # of customers, and since most assistance pertains to helping customers reduce energy use it affects production plant investment.
LABOR	Amortizations, Payroll Taxes and A&G Expenses that are labor related such as Salaries, Pension & Benefits, Injuries & Claims	Total Labor costs on Page 12 line 48 less A&G Labor on Page 12 line 46. A&G Labor is excluded to avoid a circular reference.	The specified expenses are directly related to Labor costs.
NEPIS	Property Insurance, Net Operating Loss Carryover, Misc Prepayments	Electric plant in service less accumulated provision for depreciation.	These costs are driven by net electric plant in service.
OXDTS	Distribution customer installation expenses and miscellaneous distribution expense	All Distribution O&M Expense, except Supervision and Engineering, Customer Install and Miscellaneous. Supervision & engineering expenses are excluded since they are an overhead expense. Customer installation expenses and miscellaneous distribution expense are excluded to avoid a circular reference. (lines 2 thru 7, 9 and 11 of page 8).	The OXDTS allocator represents the majority of Distribution O&M expenses (excl supervision and customer installation costs) which is a good indicator for miscellaneous distribution expenses.

Guide to the Class Cost of Service Study
INTERNAL ALLOCATORS: DESCRIPTIONS AND APPLICATIONS

Code	Allocator for:	Description	Allocator Justification
OXTS	Selected administrative and general expenses such as Office Supplies, General Advertising, Contributions and maintenance of "General" plant	All O&M costs except Regulatory Expense and any A&G costs, which are the costs to be allocated on OXTS (lines 16, 17 and 23-27 of page 8). These A&G expenses are excluded to avoid circular references.	The OXTS allocator includes all O&M expenses except regulatory expense and those A&G items that are allocated with OXTS. Representing most O&M expenses, the OXTS allocator is appropriate for allocating A&G expenses.
P10	Interchange Production Capacity (i.e. fixed) inter-company Revenues. Rate base addition production-related materials and supplies	Total Production Plant: Original Plant in Service (line 6 of page 4).	Total production plant investment is closely associated with Interchange Agreement Capacity related revenues and Miscellaneous Rate Base Production additions.
P10WoN	Interchange Production Capacity (i.e. fixed) inter-company Costs	Total Production Plant less Nuclear Fuel Original Plant in Service. Nuclear fuel is excluded since NSP Wisconsin does not have nuclear plants (Total Production Plant on line 6 of page 4 less Nuclear Fuel on line 5 of page 4).	Since Wisc. does not have nuclear plants, Total production plant investment less nuclear fuel investment is a good indicator of Interchange Agreement Capacity related expenses.
P5161A	Used to allocate Step-up sub transmission costs in the Labor Allocator development	Total Generation Set-Up Transformer original plant in service: Tran Gener Step Up (line 9 of page 4) + Distrib Substn Step Up (line 14 of page 4).	Generation step-up plant investment drives step-up generation labor costs.
P61	Distribution Substation O&M expense and Distribution Substation labor	Distribution Plant: Substations Original Plant in Service (line 18, page 4).	Substation plant original investment drives Distribution Substation plant O&M costs and Distribution Substation Labor.
P68	All costs related to Distribution Plant "Line Transformers"	Distribution Plant: Line Transformers Original Plant in Service (line 42 of page 4).	Line transformer plant investment drives all line transformer costs.
P69	All costs related to Distribution Plant "Services"	Customer-Connection "Services" Original Plant in Service (line 45 of page 4).	Distribution "Services" plant investment drives all costs of "Services."
P73	All costs related to Street Lighting	Street Lighting Original Plant in Service (line 47 of page 4).	Street Lighting plant investment drives all Street Lighting costs. The results of the direct assignment of Street Lighting costs were turned into an allocator, for use elsewhere in the CCOSS.

Code	Allocator for:	Derivation	Allocator Justification
POL	All costs related to Overhead Distribution Lines including Rental costs and Distribution overhead line rent revenues.	Distribution Plant: Overhead Lines Original Plant in Service (line 28 of page 4)	Overhead distribution line plant investment drives all costs related to Overhead Distribution Lines.
PT0	Working Cash	Total Real Estate & Property Taxes (line 49 of page 9)	Working Cash is closely related to Real Estate Taxes.
PTD	All costs related to General Plant and Electric Common Plant	Original Plant Investment: Production + Transmission + Distribution (lines 6, 13 and 48 of page 4)	Total investment in production, transmission and distribution plant is the best allocator for general and common plant.
PUL	All costs related to Underground Distribution Lines	Distribution Plant: Underground Lines Original Plant in Service (line 38 of page 4)	Underground distribution line plant investment drives all costs related to Underground Distribution Lines.
R01	Sales and economic development	Present budgeted revenues for the test year	The intent of sales and economic development expenses is to maintain or increase revenues to lessen the need for future rate increases.
RTBASE	Income Tax Addition: Avoided tax interest	Total Rate Base (line 36 of page 6)	Total rate base drives avoided tax interest.
STRATH	Step-up Transformers that are Dedicated to Hydro	Using the current Stratification for Hydro Plants, the allocator is an 83% weighting of the E8760 energy allocator and a 17% weighting of the D10S capacity allocator.	Energy vs. capacity weighting of Hydro plants drives Step-up Transformer investment. It applies to just the very small portion of generation step-up assets that are hydro-related and are located on the Distribution system, unlike all of the other generation step-up facilities that are located on the Transmission system.
TD	Transmission and Distribution Materials and Supplies that are Rate Base Additions	Total Transmission and Distribution Original Plant in Service (Lines 13 and 48 of page 4)	Total Transmission and distribution plant investment drives investment in miscellaneous transmission and distribution materials and supplies.
ZDTS	Supervision & Engineering and Customer Installation Distribution Labor	All Distribution Labor except Supervision and Engineering and Customer Installation. These items are excluded to avoid a circular reference. (All of lines 33 thru 42 on page 12, except lines 33 and 40)	Distribution labor (excluding Supervision & Engineering) drives Supervision and Engineering and Customer Installation Labor.

Analysis	Analysis Description	Data Sources and Associated Vintage
E8760 Allocator Development	This allocator is developed by multiplying customer class loads by system marginal energy costs for each hour of the 2022-2024 Test Years. The allocation is the relationship of the annual class totals of these hourly results to the retail total.	1. Test Year 8760 load shapes for each customer class are developed from five years of load research data (2015-2019). The resulting load shapes for each class are synced up to the 2021 forecasts for the 2022-2024 Test Years. 2. Hourly system marginal energy costs are based on the 2022-2024 Test Year forecasts from the Commercial Operations area.
Generation Plant Stratification Analysis	Cost stratification is the term used to identify the capital substitution analysis that separates or “stratifies” fixed generation costs into “capacity-related” and “energy-related” categories. The information used for this analysis includes the 2021 replacement costs of NSPM power plants that were developed by the Capital Asset Accounting area, and the corresponding capacity ratings for those plants. This information is used to define the “capacity-related” component for each type of non-peaking generation plant. This capacity component by plant type is recognized by dividing the peaking plant cost per kW by the non-peaking cost per kW. The remaining “energy-related” component by plant type is the percent determined by subtracting the capacity-related percent from 100 percent. This component is sub-functionalized as “energy-related,” because it represents the additional investment above the cost of a peaking plant that is made to obtain lower energy (and total) costs as compared to a peaking plant.	Based on 2021 replacement costs of all NSP Minnesota Company Power Plants.
Customer Accounting Weights	The relative costs by customer class for meter reading, back-office support, customer service and billing were developed based on current budgets and the experience of management in the Billing and Customer Service area. Residential customers are assigned a weight of 1. Based on this analysis, the other customer classes are assigned weights based on the relative differences compared to the residential class.	Based on 2022 budgets with the relative weighting estimates provided by management from the Billing and Customer Service areas.

Analysis	Analysis Description	Data Sources and Associated Vintage
Minimum System and Zero Intercept Analyses	The Minimum System and Zero Intercept Analyses is used to separate FERC accounts 364-369 into “Demand/Capacity-Related” and “Customer-Related” cost classifications. As ordered by the Commission in the Company’s 2013 rate case (E002/GR-13-868) the Company conducted an updated Minimum System study. The Company was also able to obtain the data for a Zero Intercept study. A detailed description of these studies is provided Schedule 11 of Michael Peppin’s Direct Testimony. The Minimum Distribution System method involves comparing the cost of the minimum size of each type of facility used to the cost of the actual sized facilities installed. The cost of the minimum size facilities determines the “customer” component of total costs. The “capacity” cost component is the difference between total installed cost and the minimum sized cost. The Zero Intercept method attempts to determine the portion of plant that relates to a hypothetical no load or zero intercept situation. By analyzing the actual costs of 6 years of construction work orders, installed costs per unit (e.g. cost per foot of overhead primary conductor) were obtained for equipment configurations that comprise at least 90% distribution plant in the field. The installed cost was regressed against the load carrying capacity of each equipment configuration. The zero intercept of the regression was used as the minimum system cost. The cost of the minimum size facilities determines the “customer” component of total costs.	Based on an analysis of distribution construction work orders in Minnesota that were completed from 2007 to 2020.
Customer Metering Cost per Customer	Customer metering weights are assigned to each class based on the actual replacement costs of meters, current transformers (CTs) and voltage transformers (VTs) for each customer in each class. An inventory of the meter model, CT model and VT model installed for each customer by customer class was obtained from the Company’s Meter Data Management System ("MDMS"). Metering staff provided current replacement costs for each meter model, CT model and VT model. Weighted customer metering costs including the cost of CTs and VTs were then calculated for each customer and rolled up for each customer class.	Based on a 2021 inventory of meter models, CT models and VT models for each customer. Meter, CT and VT replacement costs are for 2021.

Analysis	**Analysis Description**	**Data Sources and Associated Vintage**
Compliance Classification of Other Production O&M Costs	Based on the MPUC order in Docket Nos. E002/GR-12-961 and E002/GR-13-868, consulted with Xcel Generation Cost modeling staff to identify production Other Production O&M expenses that vary directly with energy consumption. Staff in the Generation Cost Modeling area considers Chemicals and Water as the only Other Production O&M costs that vary directly with energy output. These costs were classified as 100% energy related. The remaining cost items were split in groups based on the type of plant (i.e., Nuclear, Fossil, etc) and classified as capacity or energy related based on the plant stratification for that plant type.	2022-2024 budget detail of Other Production O&M expenses and 2021 Plant Stratification Analysis.
Direct Assignment of Overhead Secondary Distribution Line Costs to the Lighting Class	In consultation with staff in the Company's Capital Asset Accounting area, identified specific lighting costs that are included in each FERC account code for distribution plant. Discovered that all lighting plant investment is included in FERC account 373 except for the cost of wood poles that are solely used by lighting in overhead distribution areas. These costs are included in FERC account 364. This analysis quantified the amount of overhead distribution pole investment that is attributed to lighting poles only. The costs for cross arms are excluded from the analysis since cross arms are used to carry conductors which means the pole has more than street lights attached.	• TY2022 plant investment in FERC code 364 (overhead distribution poles). • The total number of overhead distribution poles based on 2021 data. • The number of street lights in overhead distribution area in 2021. • Estimated percent of distribution poles with lighting that only serve lighting load.
Customers Served by 3 Phase Vs 1 Phase Primary Distribution Lines	Customers who do not receive service off the single-phase primary distribution system should not pay the costs of this part of the distribution system. Based on data from the Company's GIS system determined the percent of customers in each class the receive service off the 3 phase or 1 phase primary distribution system. This analysis is described in Michael Peppin's Direct Testimony.	2021 listing from the GIS system of all customer premises in MN and whether they receive service off the 3 phase of 1 phase distribution system.
Customers Served by Overhead Vs Underground Transformers	C&I secondary voltage customers with underground services own the service. This analysis determined the percent of customers that are served from an underground service. These customers are excluded from the allocation of distribution service costs.	2021 listing from the GIS system of all customer premises in MN and whether they are served from an overhead or underground transformer.
Comparison of MISO's LRZ-1 historical peak hour to historical NSP System hourly loads	Conduct a comparison of MISO's LRZ-1 historical peak hour to the historical hourly loads of the NSP System. This is done to determine which hours for the 2022-2024 test years should be used to calculate the D10S class Generation and Transmission capacity cost allocator.	• NSP System Operations area has historical hourly loads for the NSP System. • MISO's most recent Loss of Load Expectations Study lists historical peak days and hours for each LRZ.

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - Minnesota
Summary of 2022 Class Cost of Service Study ($000)

UNADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	3,650,035	1,452,065	117,272	2,047,948	32,750
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,625	1,421	52	150	1
[3]	Unadjusted Operating Revenues (line 1 + line 2)	3,651,660	1,453,486	117,324	2,048,098	32,751
[4]	Present Rates (CCOSS page 2, line 2)	3,255,688	1,252,204	111,122	1,865,676	26,685
[5]	Unadjusted Deficiency (line 3 - line 4)	395,972	201,282	6,202	182,422	6,066
[6]	Defic / Pres (line 5 / line 4)	12.2%	16.1%	5.6%	9.8%	22.7%
[7]	**Ratio: Class % / Total %**	**1.00**	**1.32**	**0.46**	**0.80**	**1.87**

COST RESPONSIBILITIES FOR RATE DISCOUNTS

		Total	Residential	Non-Demand	Demand	Street Ltg
		[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS				
[8]	Interruptible Rate Discounts (CCOSS page 2, line 5)					
[9]	Economic Development Discount (CCOSS page 2, line 6)					
[10]	Interruptible Rate Disc Cost Allocation (CCOSS page 2, line 7)					
[11]	Economic Development Disc Cost Allocation (CCOSS page 2, line 8)					
				HIGHLY CONFIDENTIAL TRADE SECRET ENDS]		
[12]	Revenue Requirement Change (lines 10 & 11 - lines 8 & 9)	0	(3,981)	930	3,048	4

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[13]	Adjusted Rate Revenue Reqt (line 1 + line 12)	3,650,035	1,448,084	118,202	2,050,996	32,754
[14]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,625	1,421	52	150	1
[15]	Adjusted Operating Revenues (line 13 + line 14)	3,651,660	1,449,505	118,254	2,051,146	32,755
[16]	Present Rates (line 4)	3,255,688	1,252,204	111,122	1,865,676	26,685
[17]	Adjusted Deficiency (line 15 - line 16)	395,972	197,301	7,131	185,470	6,070
[18]	**Defic / Pres Rates (line 17 / line 16)**	**12.2%**	**15.8%**	**6.4%**	**9.9%**	**22.7%**
[19]	**Ratio: Class % / Total %**	**1.00**	**1.30**	**0.53**	**0.82**	**1.87**

PROPOSED REVENUE RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[20]	Proposed Rates (CCOSS page 3, line 3)	3,650,035	1,425,981	121,392	2,071,327	31,336
[21]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,625	1,421	52	150	1
[22]	Proposed Operating Revenues (line 20 + line 21)	3,651,660	1,427,402	121,444	2,071,477	31,337
[23]	Proposed Increase (line 22 - line 16)	395,972	175,198	10,321	205,801	4,652
[24]	Difference / Pres (line 23 / line 16)	12.2%	14.0%	9.3%	11.0%	17.4%
[25]	**Ratio: Class % / Total %**	**1.00**	**1.15**	**0.76**	**0.91**	**1.43**

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Rate Base

			1=2+3+6	2	3=4+5	4	5	6
	Plant In Service	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Production		12,602,186	4,222,815	8,347,122	371,665	7,975,457	32,249
2	Transmission		3,683,180	1,451,005	2,231,722	104,058	2,127,664	453
3	Distribution		4,387,561	2,879,251	1,366,884	177,569	1,189,315	141,427
4	General		2,052,611	849,233	1,186,089	64,865	1,121,224	17,289
5	Common		0	0	0	0	0	0
6	Total Plant In Service		22,725,537	9,402,303	13,131,817	718,157	12,413,660	191,417
7	Production		6,977,459	2,325,080	4,633,994	206,036	4,427,958	18,384
8	Transmission		818,963	323,822	495,099	23,091	472,008	42
9	Distribution		1,560,971	1,053,302	476,301	63,850	412,451	31,367
10	General		989,541	409,406	571,800	31,271	540,530	8,335
11	Common		0	0	0	0	0	0
12	Total Depreciation Reserve		10,346,933	4,111,610	6,177,195	324,248	5,852,947	58,128
13	**Net Plant In Service**		12,378,604	5,290,693	6,954,622	393,909	6,560,713	133,289
14	Deducts: Accum Defer Inc Tax		2,178,105	911,936	1,244,334	68,647	1,175,687	21,835
15	Constr Work In Progress		436,833	179,788	254,573	13,348	241,225	2,472
16	Fuel Inventory		69,767	22,024	47,510	2,084	45,426	234
17	Materials & Supplies		154,701	55,236	98,816	4,654	94,162	649
18	Prepayments		124,104	53,043	69,725	3,949	65,776	1,336
19	Non-Plant & Work Cash		(54,534)	(26,444)	(27,455)	(1,577)	(25,878)	(634)
20	Total Additions		730,872	283,646	443,169	22,458	420,710	4,057
21	**Rate Base**		10,931,371	4,662,403	6,153,457	347,720	5,805,737	115,511

Income Statement

			MN	Res	C&I Tot	Sm Non-D	Demand	St Ltg
22A	**Tot Oper Rev - Pres**		3,852,129	1,466,162	2,357,854	128,659	2,229,195	28,112
22B	**Tot Oper Rev - Prop**		4,248,100	1,641,360	2,573,976	138,981	2,434,996	32,764
23	Oper & Maint		2,488,359	925,706	1,547,745	78,822	1,468,923	14,907
24	Book Depr + IRS Int		815,505	332,911	473,738	25,625	448,114	8,856
25	Payroll, Rl Est & Prop Tax		229,910	102,002	125,472	7,500	117,972	2,435
26	Deferred Inc Tax & Net ITC		(67,718)	(35,675)	(30,324)	(2,296)	(28,028)	(1,719)
27A	Present Income Tax		(97,637)	(41,960)	(55,332)	(982)	(54,350)	(345)
27B	Proposed Income Tax		16,173	8,396	6,786	1,984	4,802	992
28	Allow Funds Dur Const		33,212	14,215	18,854	1,008	17,846	143
29A	**Present Return**		516,922	197,392	315,408	20,999	294,409	4,122
29B	**Proposed Return**		799,083	322,235	469,412	28,354	441,059	7,436
30A	**Pres Ret on Rt Base**		4.73%	4.23%	5.13%	6.04%	5.07%	3.57%
30B	**Prop Ret on Rt Base**		**7.31%**	6.91%	7.63%	8.15%	7.60%	6.44%
31A	**Pres Ret on Common**		5.29%	4.35%	6.05%	7.79%	5.94%	3.08%
31B	**Prop Ret on Common**		**10.21%**	9.45%	10.82%	11.82%	10.76%	8.55%

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PRES vs Equal Rev Reqts

			1=2+3+6	2	3=4+5	4	5	6
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	**UnAdj Equal Rev Reqt @ 7.31%**		**3,650,035**	**1,452,065**	**2,165,220**	**117,272**	**2,047,948**	**32,750**
2	**Present Revenue**		**3,255,688**	**1,252,204**	**1,976,799**	**111,122**	**1,865,676**	**26,685**
3	**UnAdj Revenue Deficiency**		**394,347**	**199,861**	**188,421**	**6,150**	**182,272**	**6,065**
4	**UnAdj Deficiency / Present**		**12.11%**	**15.96%**	**9.53%**	**5.53%**	**9.77%**	**22.73%**
			[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS					
5	**Pres Int Rate Discounts**							
6	**Pres Econ Dvlp Rate Discounts**							
7	**Pres Int Rate Disc Cost Alloc**	**D10S**						
8	**Pres Econ Dvlp Disc Cost Alloc**	**R01**						
						HIGHLY CONFIDENTIAL TRADE SECRET ENDS]		
9	**Revenue Requirement Shift**		**0**	**(3,981)**	**3,978**	**930**	**3,048**	**4**
10	**Adj Equal Rev Reqt (Rows 1+9)**		**3,650,035**	**1,448,084**	**2,169,198**	**118,202**	**2,050,996**	**32,754**
11	**Adj Rev Defic vs Pres Rev (Row 2)**		**394,347**	**195,880**	**192,399**	**7,079**	**185,320**	**6,068**
12	**Adj Deficiency / Adj Present**		**12.11%**	**15.64%**	**9.73%**	**6.37%**	**9.93%**	**22.74%**
	Equal Customer Classification							
13	Min Sys & Service Drop		277,138	228,073	24,969	15,061	9,908	24,096
14	Energy Services		68,076	57,175	10,650	5,464	5,187	251
15	Total Customer **(Cusco)**		345,214	285,247	35,620	20,525	15,094	24,347
16	Ave Monthly Customers		1,368,036	1,201,264	138,763	88,734	50,029	28,010
17	Svc Drop Reqt	$ / Mo / Cust	$16.88	$15.82	$15.00	$14.14	$16.50	$71.69
18	Ener Svcs Reqt	$ / Mo / Cust	$4.15	$3.97	$6.40	$5.13	$8.64	$0.75
19	Total Reqt	$ / Mo / Cust	$21.03	$19.79	$21.39	$19.28	$25.14	$72.43
	Equal Energy Classification							
20	On Peak Rev Reqt		869,805	265,379	602,921	27,603	575,317	1,505
21	Off Peak Rev Reqt		836,158	273,216	558,528	23,477	535,051	4,414
22	Total Ener Rev Reqt		1,705,963	538,595	1,161,449	51,081	1,110,368	5,919
23	Annual MWh Sales		28,258,778.327	8,668,299	19,468,006	821,214	18,646,792	122,473
24	On Pk Reqt	Mills / kWh	30.780	30.615	30.970	33.613	30.853	12.287
25	Off Pk Reqt	Mills / kWh	29.589	31.519	28.690	28.588	28.694	36.042
26	Total Reqt	Mills / kWh	60.369	62.134	59.659	62.202	59.547	48.329
	Equal Demand Classification							
27	Energy-Related Prod		436,066	140,684	294,053	12,963	281,090	1,330
28	Capacity-Related Summer Peak Prod		344,011	136,593	207,418	9,721	197,697	0
29	Capacity-Related Winter Peak Prod		96,114	38,163	57,951	2,716	55,235	0
30	Total Capacity-Related Prod		440,126	174,757	265,369	12,437	252,932	0
31	Total Production		876,192	315,440	559,422	25,401	534,021	1,330
32	Transmission **(Transco)**		432,899	171,676	261,223	12,215	249,008	0
33	Primary Dist Subs		77,270	31,170	45,667	2,271	43,396	433
34	Prim Dist Lines		160,650	80,576	79,449	4,286	75,164	625
35	Second Dist, Trans		51,847	29,361	22,390	1,494	20,896	96
36	Total Distribution **(Disco)**		289,768	141,107	147,506	8,051	139,456	1,154
37	Total Demand Rev Reqt		1,598,859	628,223	968,152	45,666	922,486	2,484
38	Annual Billing kW		48,418,598	0	48,418,598	0	48,418,598	0
39	Base Rev Reqt	$ / kW	$0.00	$0.00	$6.07	$0.00	$5.81	$0.00
40	Summer Rev Reqt	$ / kW	$0.00	$0.00	$4.28	$0.00	$4.08	$0.00
41	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.20	$0.00	$1.14	$0.00
42	Prod Rev Reqt	$ / kW	$0.00	$0.00	$11.55	$0.00	$11.03	$0.00
43	Tran Rev Reqt	$ / kW	$0.00	$0.00	$5.40	$0.00	$5.14	$0.00
44	Dist Rev Reqt	$ / kW	$0.00	$0.00	$3.05	$0.00	$2.88	$0.00
45	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$20.00	$0.00	$19.05	$0.00
46	Tot Dmd Rev Reqt	Mills / kWh	56.579	72.474	49.730	55.608	49.472	20.284
47	Summer Billing kW		17,860,303	0	17,860,303	0	17,860,303	0
48	Winter Billing kW		30,558,296	0	30,558,296	0	30,558,296	0
49	Tot Summer Reqt	$ / kW	$0.00	$0.00	$26.13	$0.00	$24.90	$0.00
50	Tot Winter Reqt	$ / kW	$0.00	$0.00	$16.41	$0.00	$15.64	$0.00
51	Energy + Production **(Genco)**		2,582,155	854,035	1,720,871	76,481	1,644,390	7,249

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PROP vs Equal Rev Reqts

			1=2+3+6	2	3=4+5	4	5	6
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	**Proposed Ret On Rt Base**		**7.31%**	**6.91%**	**7.63%**	**8.15%**	**7.60%**	**6.44%**
2	**UnAdj Equalized Rev Reqt**		**3,650,035**	**1,452,065**	**2,165,220**	**117,272**	**2,047,948**	**32,750**
3	**Proposed Revenue**		**3,650,035**	**1,425,981**	**2,192,718**	**121,392**	**2,071,327**	**31,336**
4	**UnAdj Revenue Deficiency**		**(0)**	**26,084**	**(27,498)**	**(4,120)**	**(23,379)**	**1,414**
5	**UnAdj Deficiency / Proposed**		**0.00%**	**1.83%**	**-1.25%**	**-3.39%**	**-1.13%**	**4.51%**
			[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS					
6	**Prop Interrupt Rate Discounts**							
7	**Prop Econ Dev Rate Discounts**							
8	**Prop Int Rate Disc Cost Alloc**	**D10S**						
9	**Prop ED Discount Cost Alloc**	**R01**						
							HIGHLY CONFIDENTIAL TRADE SECRET ENDS]	
10	**Revenue Requirement Shift**		**0**	**3,275**	**(3,280)**	**659**	**(3,939)**	**5**
11	**Adj Equal Rev (Rows 2+10)**		**3,650,035**	**1,455,341**	**2,161,940**	**117,931**	**2,044,009**	**32,754**
12	**Adj Rev Defic vs Prop Rev (Row 3)**		**(0)**	**29,360**	**(30,778)**	**(3,460)**	**(27,318)**	**1,419**
13	**Adj Deficiency / Adj Prop**		**0.00%**	**2.06%**	**-1.40%**	**-2.85%**	**-1.32%**	**4.53%**
	Prop Customer Component							
14	Min Sys & Service Drop		269,912	220,970	26,029	15,776	10,253	22,912
15	Energy Services		68,055	57,151	10,654	5,466	5,188	251
16	Total Customer **(Cusco)**		337,967	278,121	36,683	21,241	15,441	23,163
17	Ave Monthly Customers		1,368,036	1,201,264	138,763	88,734	50,029	28,010
18	Svc Drop Reqt	$ / Mo / Cust	$16.44	$15.33	$15.63	$14.82	$17.08	$68.17
19	Ener Svcs Reqt	$ / Mo / Cust	$4.15	$3.96	$6.40	$5.13	$8.64	$0.75
20	Total Reqt	$ / Mo / Cust	$20.59	$19.29	$22.03	$19.95	$25.72	$68.91
	Prop Energy Component							
21	On Peak Rev Reqt		869,646	265,228	602,914	27,616	575,298	1,504
22	Off Peak Rev Reqt		835,977	273,060	558,506	23,488	535,019	4,411
23	Total Ener Rev Reqt		1,705,622	538,288	1,161,420	51,104	1,110,316	5,914
24	Annual MWh Sales		28,258,778	8,668,299	19,468,006	821,214	18,646,792	122,473
25	On Pk Reqt	Mills / kWh	30.774	30.597	30.969	33.628	30.852	12.278
26	Off Pk Reqt	Mills / kWh	29.583	31.501	28.688	28.601	28.692	36.013
27	Total Reqt	Mills / kWh	60.357	62.098	59.658	62.229	59.545	48.291
	Prop Demand Component							
28	Energy-Related Prod		431,472	130,675	299,632	14,244	285,388	1,166
29	Capacity-Related Summer Peak Prod		354,506	137,790	216,715	10,425	206,290	0
30	Capacity-Related Winter Peak Prod		99,046	38,498	60,549	2,913	57,636	0
31	Total Capacity-Related Prod		453,552	176,288	277,264	13,338	263,926	0
32	Total Production		885,024	306,963	576,896	27,582	549,314	1,166
33	Transmission **(Transco)**		432,572	165,915	266,657	12,981	253,676	0
34	Primary Dist Subs		77,238	30,047	46,784	2,427	44,357	407
35	Prim Dist Lines		159,512	78,145	80,772	4,479	76,293	595
36	Second Dist, Trans		52,099	28,502	23,507	1,578	21,929	91
37	Total Distribution **(Disco)**		288,849	136,694	151,063	8,484	142,579	1,093
38	Total Demand Rev Reqt		1,606,446	609,572	994,616	49,047	945,569	2,258
39	Annual Billing kW		48,418,598	0	48,418,598	0	48,418,598	0
40	Base Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$5.89	$0.00
41	Summer Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$4.26	$0.00
42	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$1.19	$0.00
43	Prod Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$11.35	$0.00
44	Tran Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$5.24	$0.00
45	Dist Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$2.94	$0.00
46	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$19.53	$0.00
47	Tot Dmd Rev Reqt	Mills / kWh	56.848	70.322	51.090	59.725	50.709	18.439
48	Summer Billing kW		17,860,303	0	17,860,303	0	17,860,303	0
49	Winter Billing kW		30,558,296	0	30,558,296	0	30,558,296	0
50	Tot Summer Reqt	$ / kW	$0.00	$0.00	$26.95	$0.00	$25.63	$0.00
51	Tot Winter Reqt	$ / kW	$0.00	$0.00	$16.80	$0.00	$15.96	$0.00
52	Energy + Production **(Genco)**		2,590,647	845,251	1,738,316	78,685	1,659,630	7,080
53	Prop Rev - Pres Rev (Pg 2)		394,347	173,777	215,920	10,269	205,650	4,650
54	Difference / Present		12.11%	13.88%	10.92%	9.24%	11.02%	17.43%

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Original Plant in Service

				1=2+3+6	2	3=4+5	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Summer Peak	D10S		2,328,089	926,142	1,401,947	65,775	1,336,172	0
2	WInter Peak	D10S		650,451	258,757	391,694	18,377	373,317	0
3	Total Peak	D10S		2,978,540	1,184,899	1,793,641	84,152	1,709,489	0
4	Base Load	E8760		6,993,245	2,207,572	4,762,239	208,928	4,553,311	23,434
5	Nuclear Fuel	E8760		2,630,400	830,344	1,791,242	78,585	1,712,657	8,814
6	Total	29.87%	120, 310-346	12,602,186	4,222,815	8,347,122	371,665	7,975,457	32,249
	Transmission								
7	Gen Step Up Base	E8760		135,054	42,633	91,968	4,035	87,934	453
8	Gen Step Up Peak	D10S		35,867	14,268	21,599	1,013	20,585	0
9	Total Gen Step Up			170,921	56,901	113,567	5,048	108,519	453
10	Bulk Transmission	D10S		3,504,429	1,394,104	2,110,325	99,010	2,011,315	0
11	Distrib Function	D60Sub		0	0	0	0	0	0
12	Direct Assign	Dir Assign		7,830	0	7,830	0	7,830	0
13	Total		350-359	3,683,180	1,451,005	2,231,722	104,058	2,127,664	453
	Distribution:								
	Substations								
14	Generat Step Up	STRATH		3,050	1,007	2,034	90	1,944	8
15	Bulk Transmission	D10S		1,661	661	1,000	47	953	0
16	Distrib Function	D60Sub		725,051	300,012	420,880	21,823	399,056	4,160
17	Direct Assign	Dir Assign		17,692.073	0	17,692	0	17,692	0
18	Total		360-363	747,453	301,680	441,606	21,961	419,645	4,168
	Overhead Lines								
19	Primary Capacity 1 Phase	D61PS1Ph		153,065	114,571	37,737	4,446	33,292	757
20	Primary Capacity Multi Phase	D61PS		315,250	116,365	197,843	8,000	189,843	1,042
21	Primary Customer 1 Phase	C61PS1Ph		83,414	79,265	3,870	3,308	562	279
22	Primary Customer Multi Phase	C61PS		171,797	153,327	17,739	11,336	6,403	731
23	Total Primary			723,525	463,527	257,189	27,089	230,099	2,809
24	Second Capacity	D62SecL		60,789	30,479	30,157	1,922	28,235	153
25	Second Customer	C62Sec		223,533	199,573	23,009	14,756	8,253	951
26	Total Secondary			284,322	230,052	53,166	16,678	36,488	1,105
27	Street Lighting	DASL		52,663	0	0	0	0	52,663
28	Total		364,365	1,060,509	693,579	310,354	43,767	266,587	56,576
	Underground Lines								
29	Primary Capacity 1 Phase	D61PS1Ph		233,489	174,769	57,565	6,781	50,784	1,154
30	Primary Capacity Multi Phase	D61PS		350,582	129,406	220,016	8,896	211,120	1,159
31	Primary Customer 1 Phase	C61PS1Ph		263,715	250,599	12,235	10,458	1,777	881
32	Primary Customer Multi Phase	C61PS		395,966	353,395	40,886	26,128	14,757	1,684
33	Total Primary			1,243,751	908,170	330,702	52,264	278,438	4,879
34	Second Capacity	D62SecL		138,113	69,248	68,517	4,367	64,150	348
35	Second Customer	C62Sec		203,590	181,768	20,956	13,439	7,517	866
36	Total Secondary			341,703	251,015	89,473	17,806	71,666	1,215
37	Street Lighting	DASL		0	0	0	0	0	0
38	Total		366,367	1,585,454	1,159,185	420,175	70,070	350,105	6,094
	Line Transformers								
39	Primary	D61PS		44,586	16,458	27,981	1,131	26,850	147
40	Second Capacity	D62SecL		137,736	69,059	68,330	4,355	63,975	347
41	Second Customer	C62Sec		246,565	220,137	25,379	16,276	9,103	1,049
42	Total		368	428,887	305,653	121,690	21,763	99,928	1,544
	Services								
43	Second Capacity	D62NLL		138,101	103,390	34,711	2,892	31,819	0
44	Second Customer	C62NL		226,794	215,040	11,754	7,538	4,216	0
43	Total Services	C62NL	369	364,895	318,429	46,466	10,431	36,035	0
44	Meters	C12WM	370	127,591	100,724	26,593	9,577	17,016	274
45	Street Lighting	Dir Assign	373	72,771	0	0	0	0	72,771
46	**Total Distribution**			4,387,561	2,879,251	1,366,884	177,569	1,189,315	141,427
47	**General & Common Plant**	PTD	303, 389-399	2,052,611	849,233	1,186,089	64,865	1,121,224	17,289
48	Prelim Elec Plant			22,725,537	9,402,303	13,131,817	718,157	12,413,660	191,417
49	TBT Investment	NEPIS		0	0	0	0	0	0
50	**Elec Plant in Serv**			22,725,537	9,402,303	13,131,817	718,157	12,413,660	191,417

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Accum Deprec; Net Plant

				1=2+3+6	2	3=4+5	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		1,491,257	593,240	898,017	42,132	855,885	0
2	Decom Int Peaking	D10S		0	0	0	0	0	0
3	Decom Int Baseload	E8760		0	0	0	0	0	0
4	Nuclear Fuel	E8760		2,465,975	778,439	1,679,272	73,673	1,605,599	8,263
5	Base Load	E8760		3,020,227	953,401	2,056,705	90,231	1,966,474	10,121
6	Total		108,111,115,120.5	6,977,459	2,325,080	4,633,994	206,036	4,427,958	18,384
	Transmission								
7	Gen Step Up Base	E8760		12,475	3,938	8,495	373	8,123	42
8	Gen Step Up Peak	D10S		15,549	6,186	9,363	439	8,924	0
9	Total Gen Step Up			28,024	10,124	17,859	812	17,047	42
10	Bulk Transmission	D10S		788,558	313,698	474,860	22,279	452,581	0
11	Distrib Function	D60Sub		0	0	0	0	0	0
12	Direct Assign	Dir Assign		2,380	0	2,380	0	2,380	0
13	Total		108,111,115,120.5	818,963	323,822	495,099	23,091	472,008	42
	Distribution								
14	Generat Step Up	STRATH		1,680	555	1,120	50	1,071	5
15	Bulk Transmission	D10S		595	237	358	17	341	0
16	Distrib Function	D60Sub		237,609	98,318	137,928	7,152	130,776	1,363
17	Direct Assign	Dir Assign		6,136	0	6,136	0	6,136	0
18	Total Substations			246,020	99,109	145,542	7,218	138,324	1,368
19	Overhead Lines	POL		373,236	244,098	109,226	15,403	93,823	19,911
20	Underground	PUL		511,005	373,615	135,426	22,584	112,842	1,964
21	Line Transformers	P68		176,528	125,805	50,087	8,957	41,130	636
22	Services	P69		190,202	165,981	24,220	5,437	18,783	0
23	Meters	C12WM		56,614	44,693	11,800	4,250	7,550	121
24	Street Lighting	P73		7,367	0	0	0	0	7,367
25	Total		108,111,115,120.5	1,560,971	1,053,302	476,301	63,850	412,451	31,367
26	**General & CommonPlant**	PTD	108,111,115,120.5	989,541	409,406	571,800	31,271	540,530	8,335
27	**Total Accum Depr**			10,346,933	4,111,610	6,177,195	324,248	5,852,947	58,128
28	**Net Elec Plant**			12,378,604	5,290,693	6,954,622	393,909	6,560,713	133,289
29	**Net Plant w/ TBT**			12,378,604	5,290,693	6,954,622	393,909	6,560,713	133,289

Subtractions: Accum Defer Inc Tax

	Production								
30	Peaking Plant	D10S		303,465	120,722	182,743	8,574	174,169	0
31	Base Load	E8760		949,067	299,594	646,292	28,354	617,938	3,180
32	Nuclear Fuel	E8760		(9,133)	(2,883)	(6,219)	(273)	(5,946)	(31)
33	Total		190,281,282,283	1,243,398	417,433	822,816	36,655	786,161	3,150
	Transmission								
34	Gen Step Up Base	E8760		17,670	5,578	12,033	528	11,505	59
35	Gen Step Up Peak	D10S		3,432	1,365	2,067	97	1,970	0
36	Total Gen Step Up			21,102	6,943	14,100	625	13,475	59
37	Bulk Transmission	D10S		725,823	288,741	437,082	20,507	416,575	0
38	Distrib Function	D60Sub		0	0	0	0	0	0
39	Direct Assign	Dir Assign		1,502	0	1,502	0	1,502	0
40	Total		281,282,283	748,427	295,685	452,684	21,131	431,552	59
	Distribution								
41	Generat Step Up	STRATH		274	90	182	8	174	1
42	Bulk Transmission	D10S		246	98	148	7	141	0
43	Distrib Function	D60Sub		111,964	46,329	64,993	3,370	61,623	642
44	Direct Assign	Dir Assign		2,535	0	2,535	0	2,535	0
45	Total Substations			115,019	46,517	67,859	3,385	64,474	643
46	Overhead Lines	POL		142,466	93,174	41,692	5,880	35,813	7,600
47	Underground	PUL		226,129	165,331	59,928	9,994	49,934	869
48	Line Transformers	P68		57,555	41,018	16,330	2,920	13,410	207
49	Services	P69		20,208	17,635	2,573	578	1,996	0
50	Meters	C12WM		9,585	7,567	1,998	719	1,278	21
51	Street Lighting	P73		13,936	0	0	0	0	13,936
52	Total		281,282,283	584,899	371,241	190,381	23,476	166,905	23,276
53	**General & Common Plant**	PTD	281,282,283	141,620	58,593	81,835	4,475	77,359	1,193
54	**Total Deferred Tax**			2,718,345	1,142,952	1,547,715	85,738	1,461,977	27,678
55	Net Operating Loss (NOL) Carry F	NEPIS		(580,419)	(248,075)	(326,095)	(18,470)	(307,625)	(6,250)
56	Non-Plant Related	LABOR		40,179	17,059	22,714	1,380	21,334	406
57	**Accum Def W/ Adj**			2,178,105	911,936	1,244,334	68,647	1,175,687	21,835

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Additions: CWIP, Etc; Rate Base

				1=2+3+6	2	3=4+5	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		118,113	46,987	71,126	3,337	67,789	0
2	Base Load	E8760		14,766	4,661	10,055	441	9,614	49
3	Nuclear Fuel	E8760		95,427	30,124	64,983	2,851	62,132	320
4	Total		107	228,305	81,771	146,164	6,629	139,535	369
	Transmission								
5	Gen Step Up Base	E8760		0	0	0	0	0	0
6	Gen Step Up Peak	D10S		0	0	0	0	0	0
7	Total Gen Step Up			0	0	0	0	0	0
8	Bulk Transmission	D10S		50,530	20,101	30,428	1,428	29,001	0
9	Distrib Function	D60Sub		0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0
11	Total		107	50,530	20,101	30,428	1,428	29,001	0
	Distribution								
12	Generat Step Up	STRATH		0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0
14	Distrib Function	D60Sub		10,069	4,166	5,845	303	5,542	58
15	Direct Assign	Dir Assign		45	0	45	0	45	0
16	Total Substations			10,115	4,166	5,890	303	5,587	58
17	Overhead Lines	POL		18,473	12,081	5,406	762	4,644	986
18	Underground	PUL		28,323	20,708	7,506	1,252	6,254	109
19	Line Transformers	P68		(18,982)	(13,528)	(5,386)	(963)	(4,423)	(68)
20	Services	P69		7,394	6,453	942	211	730	0
21	Meters	C12WM		3,876	3,060	808	291	517	8
22	Street Lighting	P73		95	0	0	0	0	95
23	Total		107	49,294	32,941	15,166	1,856	13,310	1,187
24	**General & Common Plant**	PTD	107	108,705	44,975	62,814	3,435	59,379	916
25	**Total CWIP**			436,833	179,788	254,573	13,348	241,225	2,472
26	Fuel Inventory	E8760	151,152	69,767	22,024	47,510	2,084	45,426	234
	Materials & Supplies								
27	Production	P10		137,834	46,186	91,295	4,065	87,230	353
28	Trans & Distr	TD		16,867	9,050	7,521	589	6,932	297
29	Total		154	154,701	55,236	98,816	4,654	94,162	649
	Prepayments								
30	Miscellaneous	NEPIS		124,104	53,043	69,725	3,949	65,776	1,336
31	Fuel	E8760		0	0	0	0	0	0
32	Insurance	NEPIS	135,143,184,186,232	0	0	0	0	0	0
33	Total		235,252,165	124,104	53,043	69,725	3,949	65,776	1,336
34	Non-Plant Assets & Liab	LABOR	190,283,	97,858	41,548	55,320	3,360	51,960	989
35	Working Cash	PT0	calculated	(152,392)	(67,992)	(82,776)	(4,937)	(77,839)	(1,624)
36	**Total Additions**			730,872	283,646	443,169	22,458	420,710	4,057
37	**Total Rate Base**			10,931,371	4,662,403	6,153,457	347,720	5,805,737	115,511
38	**Common Rate Base (@ 52.50%)**			5,738,969.8	2,447,762	3,230,565	182,553	3,048,012	60,644

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Operating Rev (Cal Month)

		Alloc	FERC Accounts	1=2+3+6 MN	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5 Demand	6 St Ltg
	Retail Revenue								
1	Present Rate Revenue	R01; (calc)	440, 442,444,445	3,255,688	1,252,204	1,976,799	111,122	1,865,676	26,685
2	Proposed Rate Revenue	PROREV; (calc)		3,650,035	1,425,981	2,192,718	121,392	2,071,327	31,336
3	Equal Rate Revenue			3,650,035	1,452,065	2,165,220	117,272	2,047,948	32,750
	Other Retail Revenue								
4	Interdepartmental	R01; R02	448	625	241	380	21	358	5
5	Gross Earnings Tax	R01; R02	408	0	0	0	0	0	0
6	CIP Adjustment to Program Costs	E99XCIP	456	0	0	0	0	0	0
7	**Tot Other Retail Rev**			625	241	380	21	358	5
	Other Operating Revenue								
8	Interchg Prod Capacity	P10	456	441,684	148,002	292,552	13,026	279,525	1,130
9	Interchg Prod Energy	E8760	456	0	0	0	0	0	0
10	Interchg Tr Bulk Supply	D10S	456	0	0	0	0	0	0
11	Dist Int Sales; Oth Serv	E8760	412,451,456	0	0	0	0	0	0
12	Dist Overhd Line Rent	POL	454	4,737	3,098	1,386	196	1,191	253
13	Connection Charges	C11	451	1,730	1,519	175	112	63	35
14	Sales For Resale	E8760	447	0	0	0	0	0	0
15	Joint Op Agree-Other PSCo Rev	D10S	456	0	0	0	0	0	0
16	Misc Ancillary Trans Rev	D10S		221,026	87,927	133,099	6,245	126,855	0
17	MISO	D10S	456	(94,780)	(37,705)	(57,075)	(2,678)	(54,398)	0
18	Other	D10S	451,456,457	16,202	6,445	9,757	458	9,299	0
19	Late Pay Chg - Pres	R16C; R02		5,215	4,431	782	157	625	3
20	**Tot Other Op - Pres**		450	595,815	213,718	380,676	17,516	363,160	1,422
21	Incr Misc Serv - Prop	C62NL		892	846	46	30	17	0
22	Incr Inter-Dept'l - Prop	R01; R02		101	39	61	3	58	1
23	Incr Late Pay - Prop	(R16C); R02		632	537	95	19	76	0
	Tot Incr Other Op			1,625	1,421	202	52	150	1
24	**Tot Other Op - Prop**			597,440	215,139	380,878	17,568	363,311	1,423
25	**Tot Oper Rev - Pres**			3,852,129	1,466,162	2,357,854	128,659	2,229,195	28,112
26	**Tot Oper Rev - Prop**			4,248,100	1,641,360	2,573,976	138,981	2,434,996	32,764
	Tot Oper Rev - Eql			4,248,100	1,667,444	2,546,478	134,861	2,411,617	34,178

Operating & Maint (Pg 1 of 2)

		Alloc	FERC Accounts	1=2+3+6 MN	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5 Demand	6 St Ltg
	Production Expen								
27	**Fuel**	E8760	501,518,547	616,460	194,599	419,795	18,417	401,378	2,066
	Purchased Power								
28	Purchases: Cap Peak	D10S		104,057	41,395	62,662	2,940	59,722	0
29	Purchases: Cap Base	D10S		38,722	15,404	23,318	1,094	22,224	0
30	Purchases: Demand		555	142,779	56,799	85,980	4,034	81,946	0
31	Purchases: Other Energy	E8760	555	379,413	119,770	258,372	11,335	247,036	1,271
32	Tot Non-Assoc Purch			522,192	176,569	344,351	15,369	328,982	1,271
33	Interchg Agr Capacity	P10WoN	557	43,924	14,943	28,877	1,291	27,586	103
34	Interchg Agr Energy	E8760	557	14,095	4,449	9,598	421	9,177	47
35	Tot Wis Interchg Purch			58,018	19,392	38,475	1,712	36,763	150
36	**Tot Purchased Power**			580,211	195,962	382,827	17,081	365,746	1,422
	Other Production		500,502,505-507 509-514,517-519,520,						
37	Capacity Related	D10S	523-525,528-532,535,	94,171	37,462	56,709	2,661	54,048	0
38	Energy Related	E8760	539,543-546,548-550	332,188	104,862	226,212	9,924	216,288	1,113
39	Total Other Produc	22.09%	552-554,556,557 575.1-575.8	426,359	142,325	282,921	12,585	270,336	1,113
40	**Total Production**			1,623,029	532,886	1,085,543	48,083	1,037,460	4,601
41	**Transmission Exp**	D10S	560-563, 565-568 570-573	257,597	102,475	155,122	7,278	147,844	0

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Operating & Maint (Pg 2 of 2)

				1=2+3+6	2	3=4+5	4	5	6
	Distribution Expen	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Supervision & Eng'rg	ZDTS	580,590	10,653	6,985	3,182	465	2,717	487
2	Load Dispatching	T20D80	581	602	247	352	18	334	3
3	Substations	P61	582,591,592	5,728	2,312	3,384	168	3,216	32
4	Overhead Lines	POL	583,593	51,807	33,882	15,161	2,138	13,023	2,764
5	Underground Lines	PUL	584, 594	21,161	15,472	5,608	935	4,673	81
6	Line Transformers	P68	595	31	22	9	2	7	0
7	Meters	C12WM	586,597,598	1,724	1,361	359	129	230	4
8	Customer Install'n	OXDTS	587	2,570	1,655	771	105	666	144
9	Street Lighting	Dir Assign	585,596	1,751	0	0	0	0	1,751
10	Miscellaneous	OXDTS	588	21,277	13,703	6,385	871	5,513	1,189
11	Rents (Pole Attachmts)	POL	589	3,499	2,289	1,024	144	880	187
12	**Total Distribution**			120,803	77,928	36,235	4,976	31,258	6,641
13	**Customer Accounting**	C11WA	901-905	51,137	42,909	8,066	4,120	3,946	161
14	**Sales, Econ Dvlp & Other**	R01	912	7,541	2,900	4,579	257	4,321	62
	Admin & General								
15	Salaries	LABOR	920	84,540	35,894	47,791	2,903	44,889	855
16	Office Supplies	OXTS	921	59,839	22,259	37,222	1,895	35,327	358
17	Admin Transfer Credit	OXTS	922	(57,351)	(21,334)	(35,674)	(1,816)	(33,858)	(343)
18	Outside Services	LABOR	923	20,375	8,651	11,519	700	10,819	206
19	Property Insurance	NEPIS	924	7,544	3,224	4,238	240	3,998	81
20	Pensions & Benefits	LABOR	926	62,455	26,517	35,307	2,144	33,162	631
21	Injuries & Claims	LABOR	925	14,732	6,255	8,328	506	7,822	149
22	Regulatory Exp	R01; R02	928	6,427	2,472	3,903	219	3,683	53
23	General Advertising	OXTS	930.1	192	72	120	6	114	1
24	Contributions	OXTS		0	0	0	0	0	0
25	Misc General Exp	OXTS	929, 930.2	(326)	(121)	(203)	(10)	(192)	(2)
26	Rents	OXTS	931	37,268	13,863	23,182	1,180	22,001	223
27	Maint of General Plant	OXTS	935	1,089	405	677	34	643	7
28	Total			236,784	98,156	136,409	8,001	128,408	2,219
	Cust Service & Info								
29	Cust Assist Exp - Non-CIP	C11P10	908	1,004	609	383	47	336	12
30	CIP Total	E99XCIP	908	128,485.463	41,392	86,509	3,921	82,588	585
31	Instructional Advertising	C11P10	909	750	455	286	35	251	9
32	Total			130,239	42,455	87,179	4,004	83,175	605
33	Amortizations	LABOR		61,229	25,996	34,613	2,102	32,511	619
34	**Total O&M Expense**			2,488,359	925,706	1,547,745	78,822	1,468,923	14,907

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Book Depreciation

				1=2+3+6	2	3=4+5	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		125,977	50,115	75,862	3,559	72,303	0
2	Base Load	E8760		337,831	106,644	230,055	10,093	219,962	1,132
3	Total		403,413	463,809	156,759	305,917	13,652	292,265	1,132
	Transmission								
4	Gen Step Up Base	E8760		2,179	688	1,484	65	1,419	7
5	Gen Step Up Peak	D10S		1,278	508	769	36	733	0
6	Total Gen Step Up			3,457	1,196	2,253	101	2,152	7
7	Bulk Transmission	D10S		72,415	28,807	43,607	2,046	41,561	0
8	Distrib Function	D60Sub		0	0	0	0	0	0
9	Direct Assign	Dir Assign		163	0	163	0	163	0
10	Total		403,413	76,034	30,004	46,023	2,147	43,876	7
	Distribution								
11	Generat Step Up	STRATH		71	24	48	2	45	0
12	Bulk Transmission	D10S		38	15	23	1	22	0
13	Distrib Function	D60Sub		16,693	6,907	9,690	502	9,187	96
14	Direct Assign	Dir Assign		398	0	398	0	398	0
15	Total Substations		403,413	17,201	6,946	10,159	506	9,653	96
16	Overhead Lines	POL		35,895	23,476	10,505	1,481	9,023	1,915
17	Underground	PUL		39,911	29,181	10,577	1,764	8,813	153
18	Line Transformers	P68		11,882	8,468	3,371	603	2,768	43
19	Services	P69		15,208	13,272	1,937	435	1,502	0
20	Meters	C12WM		5,886	4,647	1,227	442	785	13
21	Street Lighting	P73		4,272	0	0	0	0	4,272
22	Total		403,413	130,255	85,989	37,775	5,230	32,545	6,491
23	**General & Common Plant**	PTD	403,413	145,407	60,159	84,022	4,595	79,427	1,225
24	**Total Book Deprec**		403,404	815,505	332,911	473,738	25,625	448,114	8,856

Real Estate & Property Tax

	Production								
25	Peaking Plant	D10S		28,532	11,350	17,182	806	16,376	0
26	Base Load	E8760		66,990	21,147	45,619	2,001	43,617	224
27	Total		408.1	95,522	32,497	62,800	2,807	59,993	224
	Transmission								
28	Gen Step Up Base	E8760		1,747.5148	552	1,190	52	1,138	6
29	Gen Step Up Peak	D10S		464.0999	185	279	13	266	0
30	Total Gen Step Up			2,211.6148	736	1,469	65	1,404	6
31	Bulk Transmission	D10S		45,345.2150	18,039	27,306	1,281	26,025	0
32	Distrib Function	D60Sub		0	0	0	0	0	0
33	Direct Assign	Dir Assign		101	0	101	0	101	0
34	Total		408.1	47,658.149	18,775	28,877	1,346	27,531	6
	Distribution								
35	Generat Step Up	STRATH		42	14	28	1	27	0
36	Bulk Transmission	D10S		23	9	14	1	13	0
37	Distrib Function	D60Sub		9,920	4,105	5,758	299	5,460	57
38	Direct Assign	Dir Assign		242	0	242	0	242	0
39	Total Substations			10,227	4,128	6,042	300	5,742	57
40	Overhead Lines	POL		14,510	9,489	4,246	599	3,647	774
41	Underground	PUL		21,692	15,860	5,749	959	4,790	83
42	Line Transformers	P68		5,868	4,182	1,665	298	1,367	21
43	Services	P69		4,992	4,357	636	143	493	0
44	Meters	C12WM		1,746	1,378	364	131	233	4
45	Street Lighting	P73		996	0	0	0	0	996
46	Total		408.1	60,030	39,394	18,702	2,429	16,272	1,935
47	**General & Common Plant**	PTD	408.1	0	0	0	0	0	0
48	**Tot Rl Est & Pr Tax**			203,210	90,666	110,379	6,583	103,796	2,165
49	Gross Earnings Tax	R01; R02		0	0	0	0	0	0
50	Payroll Taxes	LABOR		26,699	11,336	15,093	917	14,177	270
51	**Tot Non-Inc Taxes**			229,910	102,002	125,472	7,500	117,972	2,435

Northern States Power Company
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Provision For Defer Inc Tax

				1=2+3+6	2	3=4+5	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		20,647	8,214	12,434	583	11,850	0
2	Nuclear Fuel	E8760		(1,568)	(495)	(1,068)	(47)	(1,021)	(5)
3	Base Load	E8760		44,666	14,100	30,416	1,334	29,082	150
4	Total		410, 411	63,745	21,818	41,782	1,871	39,911	144
	Transmission								
5	Gen Step Up Base	E8760		1,037	327	706	31	675	3
6	Gen Step Up Peak	D10S		251	100	151	7	144	0
7	Total Gen Step Up			1,288	427	857	38	819	3
8	Bulk Transmission	D10S		8,184	3,256	4,928	231	4,697	0
9	Distrib Function	D60Sub		0	0	0	0	0	0
10	Direct Assign	Dir Assign		14	0	14	0	14	0
11	Total		410, 411	9,486	3,683	5,799	269	5,530	3
	Distribution								
12	Generat Step Up	STRATH		(40)	(13)	(27)	(1)	(26)	(0)
13	Bulk Transmission	D10S		(6)	(2)	(4)	(0)	(4)	0
14	Distrib Function	D60Sub		109	45	63	3	60	1
15	Direct Assign	Dir Assign		(47)	0	(47)	0	(47)	0
16	Total Substations			15	29	(14)	2	(16)	1
17	Overhead Lines	POL		1,791	1,171	524	74	450	96
18	Underground	PUL		(2,109)	(1,542)	(559)	(93)	(466)	(8)
19	Line Transformers	P68		(1,493)	(1,064)	(424)	(76)	(348)	(5)
20	Services	P69		(918)	(801)	(117)	(26)	(91)	0
21	Meters	C12WM		15	12	3	1	2	0
22	Street Lighting	P73		(443)	0	0	0	0	(443)
23	Total		410, 411	(3,142)	(2,195)	(587)	(118)	(468)	(360)
24	**General & Common Plant**	PTD	410, 411	1,175	486	679	37	642	10
25	**Net Operating Loss (NOL) Carry**	NEPIS		(164,636)	(70,366)	(92,497)	(5,239)	(87,258)	(1,773)
26	**Non - Plant Related**	LABOR	410, 411	26,878	11,412	15,194	923	14,272	272
27	**Tot Prov For Defer**			(66,494)	(35,162)	(29,629)	(2,257)	(27,372)	(1,703)

Inv Tax Credit; Total Oper Exp

	Production								
28	Peaking Plant	D10S		(275)	(110)	(166)	(8)	(158)	0
29	Base Load	E8760		(523)	(165)	(356)	(16)	(341)	(2)
30	Total		411	(799)	(275)	(522)	(23)	(499)	(2)
	Transmission								
31	Gen Step Up Base	E8760		0	0	0	0	0	0
32	Gen Step Up Peak	D10S		0	0	0	0	0	0
33	Total Gen Step Up			0	0	0	0	0	0
34	Bulk Transmission	D10S		(150)	(60)	(90)	(4)	(86)	0
35	Distrib Function	D60Sub		0	0	0	0	0	0
36	Direct Assign	Dir Assign		0	0	0	0	0	0
37	Total		411	(150)	(60)	(90)	(4)	(86)	0
	Distribution								
38	Generat Step Up	STRATH		0	0	0	0	0	0
39	Bulk Transmission	D10S		0	0	0	0	0	0
40	Distrib Function	D60Sub		0	0	0	0	0	0
41	Direct Assign	Dir Assign		0	0	0	0	0	0
42	Total Substations			0	0	0	0	0	0
43	Overhead Lines	POL		(267)	(175)	(78)	(11)	(67)	(14)
44	Underground	PUL		0	0	0	0	0	0
45	Line Transformers	P68		0	0	0	0	0	0
46	Services	P69		0	0	0	0	0	0
47	Meters	C12WM		0	0	0	0	0	0
48	Street Lighting	P73		0	0	0	0	0	0
49	Total		411	(267)	(175)	(78)	(11)	(67)	(14)
50	**General & Common Plant**	PTD	411	(7)	(3)	(4)	(0)	(4)	(0)
51	**Net Inv Tax Credit**			(1,223)	(512)	(695)	(39)	(656)	(16)
28	TBT Misc Net Exp	NEPIS		0	0	0	0	0	0
52	**Total Operating Exp**			**3,466,056**	**1,324,944**	**2,116,632**	**109,651**	**2,006,981**	**24,479**
53A	**Pres Op Inc Before Inc Tax**			**386,073**	**141,218**	**241,222**	**19,008**	**222,214**	**3,633**
53B	**Prop Op Inc Before Inc Tax**			**782,045**	**316,416**	**457,344**	**29,330**	**428,014**	**8,285**

Northern States Power Company
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Tax Deprec; Inc Tax & Return

				1=2+3+6	2	3=4+5	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		223,868	89,058	134,811	6,325	128,486	0
2	Nuclear Fuel	E8760		91,405	28,854	62,245	2,731	59,514	306
3	Base Load	E8760		565,296	178,448	384,954	16,889	368,065	1,894
4	Total		tax books	880,570	296,360	582,010	25,944	556,065	2,201
	Transmission								
5	Gen Step Up Base	E8760		6,576	2,076	4,478	196	4,282	22
6	Gen Step Up Peak	D10S		1,661	661	1,000	47	953	0
7	Total Gen Step Up			8,238	2,737	5,479	243	5,235	22
8	Bulk Transmission	D10S		111,314	44,282	67,032	3,145	63,887	0
9	Distrib Function	D60Sub		0	0	0	0	0	0
10	Direct Assign	Dir Assign		231	0	231	0	231	0
11	Total		tax books	119,782	47,019	72,741	3,388	69,353	22
	Distribution								
12	Generat Step Up	STRATH		0	0	0	0	0	0
13	Bulk Transmission	D10S		18	7	11	1	10	0
14	Distrib Function	D60Sub		18,848	7,799	10,941	567	10,374	108
15	Direct Assign	Dir Assign		258	0	258	0	258	0
16	Total Substations			19,125	7,806	11,210	568	10,642	108
17	Overhead Lines	POL		43,215	28,263	12,647	1,783	10,863	2,305
18	Underground	PUL		44,862	32,800	11,889	1,983	9,907	172
19	Line Transformers	P68		13,000	9,265	3,689	660	3,029	47
20	Services	P69		9,232	8,057	1,176	264	912	0
21	Meters	C12WM		3,636	2,870	758	273	485	8
22	Street Lighting	P73		3,293	0	0	0	0	3,293
23	Total		tax books	136,363	89,061	41,368	5,531	35,838	5,933
24	**General & Common Plant**	PTD	tax books	251,513	104,059	145,336	7,948	137,387	2,118
25	Net Operating Loss (NOL) Carry F	NEPIS		0	0	0	0	0	0
26	**Total Tax Deprec**			1,388,228	536,499	841,454	42,811	798,643	10,274
27	Interest Expense		427,431	213,161.74	90,917	119,992	6,781	113,212	2,252
28	Other Tax Timing Differ	LABOR		9,975	4,235	5,639	342	5,297	101
29	Meals & Enter	LABOR		1,160	493	656	40	616	12
30	Total Tax Deductions			1,612,525	632,144	967,742	49,974	917,768	12,639
	Inc Tax Additions								
31	Book Depreciation			815,505	332,911	473,738	25,625	448,114	8,856
32	Deferred Inc Tax & ITC			(67,717.56)	(35,675)	(30,324)	(2,296)	(28,028)	(1,719)
33	Nuclear Fuel Book Burn	E8760		100,282	31,656	68,290	2,996	65,294	336
34	Tax Capitalized Leases	PTD		35,338	14,620	20,420	1,117	19,303	298
35	Avoided Tax Interest	RTBASE		20,955	8,938	11,796	667	11,130	221
36	Total Tax Additions			904,362	352,450	543,920	28,108	515,812	7,991
37	**Total Inc Tax Adjustments**			(708,163)	(279,694)	(423,822)	(21,866)	(401,956)	(4,648)
38A	**Pres Taxable Net Income**			(322,090)	(138,476)	(182,600)	(2,858)	(179,742)	(1,015)
38B	**Prop Taxable Net Income**			73,881	36,722	33,522	7,463	26,059	3,637
39A	Pres Fed & State Inc Tax			(97,637)	(41,960)	(55,332)	(982)	(54,350)	(345)
39B	Prop Fed & State Inc Tax			16,173	8,396	6,786	1,984	4,802	992
40A	Pres Preliminary Return	(total); BASE		483,710	183,177	296,554	19,991	276,563	3,978
40B	Prop Preliminary Return	(total); BASE		765,871	308,020	450,558	27,345	423,213	7,293
41	Total AFUDC			33,212	14,215	18,854	1,008	17,846	143
42A	**Present Total Return**			516,922	197,392	315,408	20,999	294,409	4,122
42B	**Proposed Total Return**			799,083	322,235	469,412	28,354	441,059	7,436
43A	**Pres % Return on Rate Base**			4.73%	4.23%	5.13%	6.04%	5.07%	3.57%
43B	**Prop % Return on Rate Base**			7.31%	6.91%	7.63%	8.15%	7.60%	6.44%
44A	**Present Common Return**			303,760	106,475	195,416	14,219	181,197	1,869
44B	**Proposed Common Return**			585,922	231,318	349,420	21,573	327,847	5,184
45A	**Pres % Ret on Common Rt Base**			5.29%	4.35%	6.05%	7.79%	5.94%	3.08%
45B	**Prop % Ret on Common Rt Base**			10.21%	9.45%	10.82%	11.82%	10.76%	8.55%

Northern States Power Company
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	Allow For Funds Used During Constr			1=2+3+6	2	3=4+5	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		12,532	4,985	7,546	354	7,192	0
2	Nuclear Fuel	E8760		5,346	1,687	3,640	160	3,480	18
3	Base Load	E8760		(2,672)	(843)	(1,820)	(80)	(1,740)	(9)
4	Total		419.1,432	15,205	5,829	9,367	434	8,933	9
	Transmission								
5	Gen Step Up Base	E8760		0	0	0	0	0	0
6	Gen Step Up Peak	D10S		0	0	0	0	0	0
7	Total Gen Step Up			0	0	0	0	0	0
8	Bulk Transmission	D10S		4,665	1,856	2,809	132	2,677	0
9	Distrib Function	D60Sub		0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0
11	Total		419.1,432	4,665	1,856	2,809	132	2,677	0
	Distribution								
12	Generat Step Up	STRATH		0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0
14	Distrib Function	D60Sub		877	363	509	26	482	5
15	Direct Assign	Dir Assign		4	0	4	0	4	0
16	Total Substations			880	363	512	26	486	5
17	Overhead Lines	POL		831	544	243	34	209	44
18	Underground	PUL		1,353	989	359	60	299	5
19	Line Transformers	P68		0	0	0	0	0	0
20	Services	P69		832	726	106	24	82	0
21	Meters	C12WM		0	0	0	0	0	0
22	Street Lighting	P73		0	0	0	0	0	0
23	Total		419.1,432	3,897	2,622	1,220	144	1,076	55
24	**General & Common Plant**	PTD	419.1,432	9,445	3,908	5,458	298	5,159	80
25	**Total AFUDC**			33,212	14,215	18,854	1,008	17,846	143
	Labor Allocator								
	Production								
26	Other Prod - Cap	D10S		59,833	23,802	36,031	1,690	34,340	0
27	Other Prod - Ene	E8760		140,481	44,346	95,665	4,197	91,468	471
28	Total		500 through 557	200,315	68,148	131,696	5,887	125,808	471
	Transmission								
29	Stepup Subtrans	P5161A		761	253	506	22	483	2
30	Bulk Power Subs	D10S		15,605	6,208	9,397	441	8,956	0
31	Total		560 through 571	16,366	6,461	9,903	463	9,440	2
	Distribution								
32	Superv & Eng	ZDTS	580, 590	8,207	5,381	2,451	358	2,093	375
33	Load Dispatch	D10S	581	(235)	(93)	(141)	(7)	(135)	0
34	Substation	P61	582, 592	3,223	1,301	1,904	95	1,810	18
35	Overhead Lines	POL	583, 593	12,595	8,237	3,686	520	3,166	672
36	Underground Lines	PUL	584, 594	9,645	7,052	2,556	426	2,130	37
37	Line Transformer	P68	595	28	20	8	1	6	0
38	Meter	C12WM	586, 597	3,710	2,929	773	278	495	8
39	Cust Installation	ZDTS	587	2,373	1,556	709	104	605	108
40	Street Lighting	P73	585, 596	504	0	0	0	0	504
41	Miscellaneous	OXDTS	588	10,638	6,851	3,192	436	2,756	594
42	Total			50,688	33,233	15,138	2,211	12,927	2,316
43	**Cust Accounting**	C11WA	901,902,903,904,905	12,793	10,735	2,018	1,031	987	40
44	**Sales Expense**	C11P10	912	1,314	797	502	62	440	15
45	**Admin & General**	LABOR	920,921,922,923,924,	149,736	63,574	84,647	5,141	79,506	1,514
46	**Service & Inform**	C11P10	908, 909	732	444	280	35	245	8
47	**Labor**			431,943	183,393	244,183	14,831	229,353	4,367

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			1=2+3+6	2	3=4+5	4	5	
INTERNAL ALLOCATORS		Intern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	50% Cus, 50% Prod Plt	C11P10	100.00%	60.66%	38.19%	4.72%	33.47%	1.15%
2	Peaking Plant Capacity	D10S	100.00%	39.78%	60.22%	2.83%	57.39%	0.00%
3	57% Dmd; 43% Energy: Sales & E	D57E43	100.00%	31.57%	68.10%	2.99%	65.11%	0.34%
4	40% Dmd; 60% Energy: CIP	D40E60	100.00%	31.57%	68.10%	2.99%	65.11%	0.34%
5	20%D10T; 80%D60Sub	T20D80	100.00%	41.06%	58.48%	2.97%	55.51%	0.46%
6	Labor w/o (or w/) A&G	LABOR	100.00%	42.46%	56.53%	3.43%	53.10%	1.01%
7	Net Plant In Service	NEPIS	100.00%	42.74%	56.18%	3.18%	53.00%	1.08%
8	Dis O&M w/o Sup & Misc	OXDTS	100.00%	64.41%	30.01%	4.10%	25.91%	5.59%
9	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	100.00%	37.20%	62.20%	3.17%	59.04%	0.60%
10	Production Plant	P10	100.00%	33.51%	66.24%	2.95%	63.29%	0.26%
11	Production Plant Wo Nuclear	P10WoN	100.00%	34.02%	65.74%	2.94%	62.81%	0.24%
12	Total P51 & P61A	P5161A	100.00%	33.29%	66.45%	2.95%	63.50%	0.26%
13	Distribution Plant	P60	100.00%	65.62%	31.15%	4.05%	27.11%	3.22%
14	Distr Substn Plant	P61	100.00%	40.36%	59.08%	2.94%	56.14%	0.56%
15	Line Transformer Plant	P68	100.00%	71.27%	28.37%	5.07%	23.30%	0.36%
16	Services Plant	P69	100.00%	87.27%	12.73%	2.86%	9.88%	0.00%
17	Dist Plt Overhead Lines	POL	100.00%	65.40%	29.26%	4.13%	25.14%	5.33%
18	Real Est & Property Tax	PT0	100.00%	44.62%	54.32%	3.24%	51.08%	1.07%
19	Produc, Trans & Distrib	PTD	100.00%	41.37%	57.78%	3.16%	54.62%	0.84%
20	Dist Plt Undground Lines	PUL	100.00%	73.11%	26.50%	4.42%	22.08%	0.38%
21	Rate Base (Non-Column)	RTBASE	100.00%	42.65%	56.29%	3.18%	53.11%	1.06%
22	Stratified Hydro Baseload	STRATH	100.00%	33.03%	66.69%	2.96%	63.73%	0.28%
23	Transmission & Distrib	TD	100.00%	53.65%	44.59%	3.49%	41.10%	1.76%
24	Labor Dis w/o Sup & Eng	ZDTS	100.00%	65.57%	29.87%	4.36%	25.50%	4.57%

			1=2+3+6	2	3=4+5	4	5	6
INTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
25	Labor w/o A&G	LABOR(S)	282,208	119,819	159,536	9,689	149,846	2,853
26	Dis O&M w/o Sup, Cust Install & M	OXDTS	86,303	55,584	25,897	3,535	22,363	4,822
27	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	2,441,221	908,091	1,518,519	77,314	1,441,205	14,611
28	Total P51 & P61A	P5161A	173,971	57,908	115,601	5,138	110,463	461
29	Produc, Trans & Distrib	PTD	20,672,927	8,553,070	11,945,728	653,292	11,292,436	174,128
30	Transmission & Distrib	TD	8,070,741	4,330,256	3,598,606	281,627	3,316,980	141,879
31	Labor Dis w/o Sup & Eng, Cust In	ZDTS	40,108	26,297	11,978	1,750	10,229	1,833

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PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

			1=2+3+6	2	3=4+5	4	5	6
EXTERNAL ALLOCATORS		Extern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Customers - Ave Monthly	C11	100.00%	87.81%	10.14%	6.49%	3.66%	2.05%
2	Cust Acctg Wtg Factor	C11WA	100.00%	83.91%	15.77%	8.06%	7.72%	0.32%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	78.94%	20.84%	7.51%	13.34%	0.21%
4	Sec & Pri Customers	C61PS	100.00%	89.25%	10.33%	6.60%	3.73%	0.43%
5	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	100.00%	95.03%	4.64%	3.97%	0.67%	0.33%
6	C62Sec, w/o Ltg & C/I Undergrou	C62NL	100.00%	94.82%	5.18%	3.32%	1.86%	0.00%
7	Secondary Customers	C62Sec	100.00%	89.28%	10.29%	6.60%	3.69%	0.43%
8	Summer Peak Resp KW	D10S	100.00%	39.78%	60.22%	2.83%	57.39%	0.00%
9	Transmission Demand %	D10T	100.00%	37.97%	61.71%	2.98%	58.73%	0.32%
10	Winter Peak Resp KW	D10W	100.00%	35.38%	63.84%	3.19%	60.64%	0.78%
11	Alternative Production Allocator	4CP	100.00%	37.23%	62.77%	2.73%	60.03%	0.00%
12	Sec, Pri & TT, Class Coin kW @ S	D60Sub	100.00%	41.38%	58.05%	3.01%	55.04%	0.57%
13	Sec & Pri, Cl Coin kW (no Min Sy	D61PS	100.00%	36.91%	62.76%	2.54%	60.22%	0.33%
14	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	100.00%	74.85%	24.65%	2.90%	21.75%	0.49%
15	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	100.00%	74.87%	25.13%	2.09%	23.04%	0.00%
16	Sec, Class Coin kW (w/o Min Sys	D62SecL	100.00%	50.14%	49.61%	3.16%	46.45%	0.25%
17	Direct Assign Street Lighting	DASL	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%
18	On + Off Sales MWH	E8760	100.00%	31.57%	68.10%	2.99%	65.11%	0.34%
19	Street Lighting (Dir Assign)	P73	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%
20	MWh Sales Excl CIP Exempt	E99XCIP	100.00%	32.22%	67.33%	3.05%	64.278%	0.46%
21	Present Rev	R01	100.0000%	38.4620%	60.7183%	3.4132%	57.3051%	0.8196%
22	Late Fee Revenue Allocator	LateFee	100.00%	84.95%	14.99%	3.01%	11.98%	0.06%

			1=2+3+6	2	3=4+5	4	5	6
EXTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
23	Customers - B Basis	C10	1,341,785	1,197,510	138,567	88,539	50,029	5,708
24	Cust - Ave Monthly (C10-Area Lt)	C11	1,368,036	1,201,264	138,763	88,734	50,029	28,010
25	Mo Cus Wtd By Cus Acct	C11WA	1,431,601	1,201,264	225,818	115,354	110,464	4,519
26	Cust Acctg Wtg Factor	C11WAF	18.85	1.00	17.85	1.30	16.55	N/A
27	Cust-Ave Mo (C11 w/ Dir Assign S	C12	1,342,895	1,201,264	138,763	88,734	50,029	2,869
28	Mo Cus Wtd By Mtr Invest	C12WM	147,421,290	116,378,967	30,726,260	11,065,900	19,660,360	316,063
29	Meter Invest / Cust Factor	C12WMF	10,636	97	10,429	125	10,304	110
30	Sec & Pri Customers	C61PS	1,341,763	1,197,510	138,545	88,539	50,007	5,708
31	% Served by Primary Single Phase		0.0%	72.72%	0.00%	41.04%	0.00%	53.62%
32	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	916,386	870,809	42,516	36,340	6,176	3,061
33	C62Sec, w/o Ltg & C/I Undergrou	C62NL	1,262,967	1,197,510	65,457	41,978	23,479	0
34	Secondary Customers	C62Sec	1,341,278	1,197,510	138,060	88,539	49,521	5,708
35	Summer Peak Resp KW	D10S	35,610	14,166	21,444	1,006	20,438	0
36	Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	3,796,604	6,171,078	297,732	5,873,345	32,318
37	Winter Peak Resp KW	D10W	4,099	1,450	2,616	131	2,486	32
38	Alternative Production Allocator	4CP	4,959	1,846	3,112	135	2,977	0
39	Sec, Pri & TT, Class Coin kW @ S	D60Sub	6,276,840	2,597,232	3,643,599	188,928	3,454,670	36,010
40	Sec & Pri, Class Coin kW (w/o Mi	D61PS	5,609,175	2,070,452	3,520,174	142,337	3,377,837	18,548
41	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	2,011,456	1,505,599	495,912	58,421	437,492	9,945
42	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	11,163,092	8,357,281	2,805,811	233,806	2,572,005	0
43	Sec, Class Coin kW (w/o Min Sys	D62SecL	10,000,000	5,013,856	4,960,928	316,212	4,644,716	25,216
44	Annual Billing kW	D99	48,418.598	0	48,419	0	48,419	0
45	Summer Billing kW	D99S	17,860.303	0	17,860	0	17,860	0
46	Winter Billing kW	D99W	30,558.296	0	30,558	0	30,558	0
47	Non-Coinc Pk Second	DN-Sec	14,293,740	8,357,281	5,917,910	493,134	5,424,776	18,548
48	MWh Sales	E99	28,258,778	8,668,299	19,468,006	821,214	18,646,792	122,473
49	MWh Sales Excl CIP Exempt	E99XCIP	26,907,545	8,668,299	18,116,773	821,098	17,295,675	122,473

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA EXCISED

Northern States Power Company Docket No. E002/GR-21-630
Electric Utility - Minnesota Exhibit___(MAP-1), Schedule 5
Summary of 2023 Class Cost of Service Study ($000) Page 1 of 1

UNADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	3,758,453	1,517,670	120,484	2,086,873	33,426
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,876	1,635	60	180	1
[3]	Unadjusted Operating Revenues (line 1 + line 2)	3,760,329	1,519,305	120,544	2,087,053	33,427
[4]	Present Rates (CCOSS page 2, line 2)	3,214,206	1,246,213	109,752	1,831,563	26,677
[5]	Unadjusted Deficiency (line 3 - line 4)	546,123	273,092	10,791	255,490	6,750
[6]	Defic / Pres (line 5 / line 4)	17.0%	21.9%	9.8%	13.9%	25.3%
[7]	**Ratio: Class % / Total %**	**1.00**	**1.29**	**0.58**	**0.82**	**1.49**

COST RESPONSIBILITIES FOR RATE DISCOUNTS

		Total	Residential	Non-Demand	Demand	Street Ltg
		[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS				
[8]	Interruptible Rate Discounts (CCOSS page 2, line 5)					
[9]	Economic Development Discount (CCOSS page 2, line 6)					
[10]	Interruptible Rate Disc Cost Allocation (CCOSS page 2, line 7)					
[11]	Economic Development Disc Cost Allocation (CCOSS page 2, line 8)					
						HIGHLY CONFIDENTIAL TRADE SECRET ENDS]
[12]	Revenue Requirement Change (lines 10 & 11 - lines 8 & 9)	0	(3,953)	901	3,048	5

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[13]	Adjusted Rate Revenue Reqt (line 1 + line 12)	3,758,453	1,513,717	121,385	2,089,921	33,431
[14]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,876	1,635	60	180	1
[15]	Adjusted Operating Revenues (line 13 + line 14)	3,760,329	1,515,352	121,444	2,090,101	33,432
[16]	Present Rates (line 4)	3,214,206	1,246,213	109,752	1,831,563	26,677
[17]	Adjusted Deficiency (line 15 - line 16)	546,123	269,139	11,692	258,537	6,755
[18]	**Defic / Pres Rates (line 17 / line 16)**	**17.0%**	**21.6%**	**10.7%**	**14.1%**	**25.3%**
[19]	**Ratio: Class % / Total %**	**1.00**	**1.27**	**0.63**	**0.83**	**1.49**

PROPOSED REVENUE RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[20]	Proposed Rates (CCOSS page 3, line 3)	3,758,453	1,485,473	124,860	2,115,807	32,313
[21]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,876	1,635	60	180	1
[22]	Proposed Operating Revenues (line 20 + line 21)	3,760,329	1,487,108	124,920	2,115,987	32,314
[23]	Proposed Increase (line 22 - line 16)	546,123	240,895	15,168	284,424	5,637
[24]	Difference / Pres (line 23 / line 16)	17.0%	19.3%	13.8%	15.5%	21.1%
[25]	**Ratio: Class % / Total %**	**1.00**	**1.14**	**0.81**	**0.91**	**1.24**

Northern States Power Company
Electric Utility - Minnesota
2023 Class Cost of Service Study ($000)

Rate Base

	Plant In Service	Alloc	1=2+3+6 MN	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5 Demand	6 St Ltg
1	Production		12,543,687	4,229,926	8,280,553	368,158	7,912,395	33,209
2	Transmission		3,878,352	1,532,803	2,345,071	108,326	2,236,744	479
3	Distribution		4,744,230	3,128,997	1,472,628	192,973	1,279,656	142,605
4	General		2,339,416	982,764	1,337,167	73,992	1,263,175	19,485
5	Common		0	0	0	0	0	0
6	Total Plant In Service		23,505,685	9,874,489	13,435,419	743,450	12,691,969	195,777
7	Production		7,096,188	2,370,700	4,705,747	208,787	4,496,960	19,741
8	Transmission		881,905	349,632	532,221	24,585	507,636	52
9	Distribution		1,644,203	1,107,175	503,837	66,646	437,191	33,192
10	General		1,157,461	486,237	661,584	36,609	624,975	9,640
11	Common		0	0	0	0	0	0
12	Total Depreciation Reserve		10,779,757	4,313,744	6,403,388	336,626	6,066,762	62,624
13	**Net Plant In Service**		12,725,928	5,560,745	7,032,031	406,823	6,625,207	133,153
14	Deducts: Accum Defer Inc Tax		2,087,146	864,731	1,202,324	64,993	1,137,331	20,090
15	Constr Work In Progress		506,554	217,221	286,793	15,092	271,701	2,541
16	Fuel Inventory		69,767	22,064	47,456	2,081	45,374	247
17	Materials & Supplies		154,701	55,599	98,457	4,635	93,822	645
18	Prepayments		116,242	50,793	64,232	3,716	60,516	1,216
19	Non-Plant & Work Cash		(40,360)	(21,895)	(17,959)	(1,121)	(16,838)	(505)
20	Total Additions		806,904	323,781	478,979	24,403	454,576	4,144
21	**Rate Base**		11,445,687	5,019,795	6,308,685	366,233	5,942,452	117,207

Income Statement

		1=2+3+6 MN	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5 Demand	6 St Ltg
22A	**Tot Oper Rev - Pres**	3,824,063	1,465,911	2,329,987	127,571	2,202,416	28,164
22B	**Tot Oper Rev - Prop**	4,370,186	1,706,806	2,629,579	142,739	2,486,840	33,801
23	Oper & Maint	2,524,296	939,920	1,569,118	79,324	1,489,795	15,257
24	Book Depr + IRS Int	849,115	354,962	485,158	26,751	458,407	8,995
25	Payroll, Rl Est & Prop Tax	243,495	109,748	131,214	7,952	123,262	2,534
26	Deferred Inc Tax & Net ITC	(119,735)	(53,702)	(64,095)	(3,937)	(60,158)	(1,939)
27A	Present Income Tax	(85,432)	(42,272)	(42,857)	(550)	(42,307)	(303)
27B	Proposed Income Tax	71,535	26,966	43,252	3,810	39,442	1,317
28	Allow Funds Dur Const	31,766	13,587	18,076	941	17,135	103
29A	**Present Return**	444,090	170,841	269,526	18,972	250,554	3,723
29B	**Proposed Return**	833,246	342,498	483,008	29,780	453,228	7,740
30A	**Pres Ret on Rt Base**	3.88%	3.40%	4.27%	5.18%	4.22%	3.18%
30B	**Prop Ret on Rt Base**	**7.28%**	6.82%	7.66%	8.13%	7.63%	6.60%
31A	**Pres Ret on Common**	3.73%	2.83%	4.48%	6.21%	4.37%	2.39%
31B	**Prop Ret on Common**	**10.21%**	9.34%	10.93%	11.83%	10.87%	8.92%

Northern States Power Company
Electric Utility - Minnesota
2023 Class Cost of Service Study ($000)

PRES vs Equal Rev Reqts

			1=2+3+6	2	3=4+5	4	5	6
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	**UnAdj Equal Rev Reqt @ 7.28%**		**3,758,453**	**1,517,670**	**2,207,357**	**120,484**	**2,086,873**	**33,426**
2	**Present Revenue**		**3,214,206**	**1,246,213**	**1,941,315**	**109,752**	**1,831,563**	**26,677**
3	**UnAdj Revenue Deficiency**		**544,247**	**271,457**	**266,042**	**10,732**	**255,310**	**6,749**
4	**UnAdj Deficiency / Present**		**16.93%**	**21.78%**	**13.70%**	**9.78%**	**13.94%**	**25.30%**
			[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS					
5	**Pres Int Rate Discounts**							
6	**Pres Econ Dvlp Rate Discounts**							
7	**Pres Int Rate Disc Cost Alloc**	**D10S**						
8	**Pres Econ Dvlp Disc Cost Alloc**	**R01**						
						HIGHLY CONFIDENTIAL TRADE SECRET ENDS]		
9	**Revenue Requirement Shift**		**0**	**(3,953)**	**3,948**	**901**	**3,048**	**5**
10	**Adj Equal Rev Reqt (Rows 1+9)**		**3,758,453**	**1,513,717**	**2,211,305**	**121,385**	**2,089,921**	**33,431**
11	**Adj Rev Defic vs Pres Rev (Row 2)**		**544,247**	**267,504**	**269,990**	**11,632**	**258,358**	**6,753**
12	**Adj Deficiency / Adj Present**		**16.93%**	**21.47%**	**13.91%**	**10.60%**	**14.11%**	**25.31%**
	Equal Customer Classification							
13	Min Sys & Service Drop		311,019	257,055	29,628	17,142	12,486	24,336
14	Energy Services		61,656	51,810	9,611	4,935	4,676	234
15	Total Customer **(Cusco)**		372,675	308,866	39,240	22,077	17,163	24,570
16	Ave Monthly Customers		1,379,292	1,211,549	139,642	89,296	50,346	28,101
17	Svc Drop Reqt	$ / Mo / Cust	$18.79	$17.68	$17.68	$16.00	$20.67	$72.17
18	Ener Svcs Reqt	$ / Mo / Cust	$3.73	$3.56	$5.74	$4.61	$7.74	$0.69
19	Total Reqt	$ / Mo / Cust	$22.52	$21.24	$23.42	$20.60	$28.41	$72.86
	Equal Energy Classification							
20	On Peak Rev Reqt		828,139	252,605	574,052	26,290	547,762	1,482
21	Off Peak Rev Reqt		873,420	285,876	582,799	24,599	558,201	4,744
22	Total Ener Rev Reqt		1,701,559	538,482	1,156,851	50,889	1,105,963	6,226
23	Annual MWh Sales		27,973,458.742	8,648,531	19,202,079	813,063	18,389,015	122,850
24	On Pk Reqt	Mills / kWh	29.604	29.208	29.895	32.335	29.787	12.063
25	Off Pk Reqt	Mills / kWh	31.223	33.055	30.351	30.254	30.355	38.619
26	Total Reqt	Mills / kWh	60.828	62.263	60.246	62.589	60.143	50.682
	Equal Demand Classification							
27	Energy-Related Prod		417,260	135,109	280,814	12,371	268,442	1,338
28	Capacity-Related Summer Peak Prod		373,485	148,727	224,758	10,431	214,327	0
29	Capacity-Related Winter Peak Prod		102,130	40,670	61,460	2,852	58,608	0
30	Total Capacity-Related Prod		475,615	189,397	286,219	13,284	272,935	0
31	Total Production		892,875	324,505	567,032	25,655	541,377	1,338
32	Transmission **(Transco)**		470,347	187,068	283,279	13,117	270,163	0
33	Primary Dist Subs		84,857	34,291	50,071	2,472	47,598	495
34	Prim Dist Lines		171,774	86,084	84,996	4,519	80,477	693
35	Second Dist, Trans		64,365	38,375	25,888	1,755	24,132	103
36	Total Distribution **(Disco)**		320,996	158,750	160,954	8,747	152,208	1,291
37	Total Demand Rev Reqt		1,684,218	670,323	1,011,266	47,518	963,748	2,629
38	Annual Billing kW		47,757,364	0	47,757,364	0	47,757,364	0
39	Base Rev Reqt	$ / kW	$0.00	$0.00	$5.88	$0.00	$5.62	$0.00
40	Summer Rev Reqt	$ / kW	$0.00	$0.00	$4.71	$0.00	$4.49	$0.00
41	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.29	$0.00	$1.23	$0.00
42	Prod Rev Reqt	$ / kW	$0.00	$0.00	$11.87	$0.00	$11.34	$0.00
43	Tran Rev Reqt	$ / kW	$0.00	$0.00	$5.93	$0.00	$5.66	$0.00
44	Dist Rev Reqt	$ / kW	$0.00	$0.00	$3.37	$0.00	$3.19	$0.00
45	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$21.18	$0.00	$20.18	$0.00
46	Tot Dmd Rev Reqt	Mills / kWh	60.208	77.507	52.664	58.444	52.409	21.403
47	Summer Billing kW		17,327,495	0	17,327,495	0	17,327,495	0
48	Winter Billing kW		30,429,869	0	30,429,869	0	30,429,869	0
49	Tot Summer Reqt	$ / kW	$0.00	$0.00	$28.15	$0.00	$26.83	$0.00
50	Tot Winter Reqt	$ / kW	$0.00	$0.00	$17.20	$0.00	$16.39	$0.00
51	Energy + Production **(Genco)**		2,594,435	862,987	1,723,884	76,544	1,647,340	7,564

Northern States Power Company
Electric Utility - Minnesota
2023 Class Cost of Service Study ($000)

PROP vs Equal Rev Reqts

			1=2+3+6	2	3=4+5	4	5	6
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	**Proposed Ret On Rt Base**		**7.28%**	**6.82%**	**7.66%**	**8.13%**	**7.63%**	**6.60%**
2	**UnAdj Equalized Rev Reqt**		**3,758,453**	**1,517,670**	**2,207,357**	**120,484**	**2,086,873**	**33,426**
3	**Proposed Revenue**		**3,758,453**	**1,485,473**	**2,240,667**	**124,860**	**2,115,807**	**32,313**
4	**UnAdj Revenue Deficiency**		**(0)**	**32,197**	**(33,310)**	**(4,376)**	**(28,934)**	**1,113**
5	**UnAdj Deficiency / Proposed**		**0.00%**	**2.17%**	**-1.49%**	**-3.51%**	**-1.37%**	**3.44%**
			[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS					
6	**Prop Interrupt Rate Discounts**							
7	**Prop Econ Dev Rate Discounts**							
8	**Prop Int Rate Disc Cost Alloc**	**D10S**						
9	**Prop ED Discount Cost Alloc**	**R01**						
								HIGHLY CONFIDENTIAL TRADE SECRET ENDS]
10	**Revenue Requirement Shift**		**0**	**3,278**	**(3,284)**	**643**	**(3,928)**	**6**
11	**Adj Equal Rev (Rows 2+10)**		**3,758,453**	**1,520,948**	**2,204,073**	**121,128**	**2,082,946**	**33,432**
12	**Adj Rev Defic vs Prop Rev (Row 3)**		**(0)**	**35,475**	**(36,594)**	**(3,733)**	**(32,861)**	**1,119**
13	**Adj Deficiency / Adj Prop**		**0.00%**	**2.39%**	**-1.63%**	**-2.99%**	**-1.55%**	**3.46%**
	Prop Customer Component							
14	Min Sys & Service Drop		301,393	247,064	30,923	17,956	12,968	23,406
15	Energy Services		61,634	51,785	9,615	4,937	4,678	234
16	Total Customer **(Cusco)**		363,027	298,848	40,538	22,893	17,646	23,640
17	Ave Monthly Customers		1,379,292	1,211,549	139,642	89,296	50,346	28,101
18	Svc Drop Reqt	$ / Mo / Cust	$18.21	$16.99	$18.45	$16.76	$21.46	$69.41
19	Ener Svcs Reqt	$ / Mo / Cust	$3.72	$3.56	$5.74	$4.61	$7.74	$0.69
20	Total Reqt	$ / Mo / Cust	$21.93	$20.56	$24.19	$21.36	$29.21	$70.10
	Prop Energy Component							
21	On Peak Rev Reqt		828,017	252,454	574,082	26,303	547,779	1,481
22	Off Peak Rev Reqt		873,260	285,705	582,814	24,611	558,203	4,741
23	Total Ener Rev Reqt		1,701,277	538,159	1,156,896	50,914	1,105,982	6,222
24	Annual MWh Sales		27,973,459	8,648,531	19,202,079	813,063	18,389,015	122,850
25	On Pk Reqt	Mills / kWh	29.600	29.190	29.897	32.350	29.788	12.056
26	Off Pk Reqt	Mills / kWh	31.217	33.035	30.352	30.269	30.355	38.594
27	Total Reqt	Mills / kWh	60.818	62.225	60.248	62.620	60.144	50.651
	Prop Demand Component							
28	Energy-Related Prod		411,649	124,314	286,125	13,490	272,635	1,210
29	Capacity-Related Summer Peak Prod		386,053	149,793	236,260	11,260	225,000	0
30	Capacity-Related Winter Peak Prod		105,566	40,961	64,606	3,079	61,526	0
31	Total Capacity-Related Prod		491,619	190,754	300,866	14,340	286,526	0
32	Total Production		903,268	315,068	586,990	27,829	559,161	1,210
33	Transmission **(Transco)**		471,120	180,409	290,712	13,990	276,722	0
34	Primary Dist Subs		85,336	33,060	51,800	2,664	49,136	476
35	Prim Dist Lines		170,082	82,943	86,472	4,721	81,751	667
36	Second Dist, Trans		64,343	36,986	27,259	1,850	25,409	98
37	Total Distribution **(Disco)**		319,761	152,990	165,531	9,235	156,296	1,241
38	Total Demand Rev Reqt		1,694,149	648,466	1,043,233	51,054	992,179	2,450
39	Annual Billing kW		47,757,364	0	47,757,364	0	47,757,364	0
40	Base Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$5.71	$0.00
41	Summer Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$4.71	$0.00
42	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$1.29	$0.00
43	Prod Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$11.71	$0.00
44	Tran Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$5.79	$0.00
45	Dist Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$3.27	$0.00
46	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$20.78	$0.00
47	Tot Dmd Rev Reqt	Mills / kWh	60.563	74.980	54.329	62.792	53.955	19.947
48	Summer Billing kW		17,327,495	0	17,327,495	0	17,327,495	0
49	Winter Billing kW		30,429,869	0	30,429,869	0	30,429,869	0
50	Tot Summer Reqt	$ / kW	$0.00	$0.00	$29.18	$0.00	$27.76	$0.00
51	Tot Winter Reqt	$ / kW	$0.00	$0.00	$17.67	$0.00	$16.80	$0.00
52	Energy + Production **(Genco)**		2,604,545	853,226	1,743,886	78,743	1,665,143	7,432
53	Prop Rev - Pres Rev (Pg 2)		544,247	239,260	299,352	15,108	284,244	5,636
54	Difference / Present		16.93%	19.20%	15.42%	13.77%	15.52%	21.13%

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Original Plant in Service

				1=2+3+6	2	3=4+5	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Summer Peak	D10S		2,496,605	996,031	1,500,574	69,716	1,430,858	0
2	WInter Peak	D10S		682,699	272,366	410,334	19,064	391,270	0
3	Total Peak	D10S		3,179,304	1,268,396	1,910,908	88,780	1,822,128	0
4	Base Load	E8760		6,631,296	2,097,178	4,510,602	197,839	4,312,763	23,516
5	Nuclear Fuel	E8760		2,733,087	864,351	1,859,043	81,539	1,777,504	9,692
6	Total	32.41%	120, 310-346	12,543,687	4,229,926	8,280,553	368,158	7,912,395	33,209
	Transmission								
7	Gen Step Up Base	E8760		135,054	42,711	91,863	4,029	87,834	479
8	Gen Step Up Peak	D10S		35,974	14,352	21,622	1,005	20,617	0
9	Total Gen Step Up			171,027	57,063	113,485	5,034	108,452	479
10	Bulk Transmission	D10S		3,699,021	1,475,739	2,223,281	103,293	2,119,989	0
11	Distrib Function	D60Sub		0	0	0	0	0	0
12	Direct Assign	Dir Assign		8,304	0	8,304	0	8,304	0
13	Total		350-359	3,878,352	1,532,803	2,345,071	108,326	2,236,744	479
	Distribution:								
	Substations								
14	Generat Step Up	STRATH		3,050	1,009	2,031	90	1,941	9
15	Bulk Transmission	D10S		1,764	704	1,060	49	1,011	0
16	Distrib Function	D60Sub		769,279	318,865	445,820	22,953	422,867	4,593
17	Direct Assign	Dir Assign		18,766.997	0	18,767	0	18,767	0
18	Total		360-363	792,859	320,579	467,679	23,092	444,587	4,602
	Overhead Lines								
19	Primary Capacity 1 Phase	D61PS1Ph		167,706	125,488	41,357	4,806	36,551	861
20	Primary Capacity Multi Phase	D61PS		345,405	127,369	216,850	8,642	208,208	1,186
21	Primary Customer 1 Phase	C61PS1Ph		91,393	86,854	4,231	3,617	615	307
22	Primary Customer Multi Phase	C61PS		188,231	168,027	19,397	12,396	7,001	807
23	Total Primary			792,735	507,738	281,836	29,461	252,375	3,161
24	Second Capacity	D62SecL		66,604	33,394	33,037	2,085	30,952	173
25	Second Customer	C62Sec		244,915	218,705	25,160	16,135	9,025	1,050
26	Total Secondary			311,519	252,100	58,197	18,220	39,977	1,223
27	Street Lighting	DASL		54,635	0	0	0	0	54,635
28	Total		364,365	1,158,890	759,838	340,032	47,681	292,352	59,020
	Underground Lines								
29	Primary Capacity 1 Phase	D61PS1Ph		243,074	181,883	59,942	6,966	52,977	1,248
30	Primary Capacity Multi Phase	D61PS		364,974	134,585	229,136	9,132	220,004	1,253
31	Primary Customer 1 Phase	C61PS1Ph		274,541	260,907	12,710	10,864	1,846	924
32	Primary Customer Multi Phase	C61PS		412,221	367,974	42,480	27,147	15,333	1,767
33	Total Primary			1,294,810	945,349	344,268	54,108	290,160	5,192
34	Second Capacity	D62SecL		143,783	72,090	71,319	4,502	66,817	373
35	Second Customer	C62Sec		211,948	189,266	21,773	13,963	7,810	909
36	Total Secondary			355,730	261,356	93,092	18,465	74,628	1,282
37	Street Lighting	DASL		0	0	0	0	0	0
38	Total		366,367	1,650,540	1,206,705	437,361	72,573	364,787	6,474
	Line Transformers								
39	Primary	D61PS		43,596	16,076	27,370	1,091	26,279	150
40	Second Capacity	D62SecL		134,677	67,525	66,803	4,217	62,586	349
41	Second Customer	C62Sec		241,090	215,289	24,767	15,883	8,884	1,034
42	Total		368	419,363	298,890	118,940	21,190	97,749	1,533
	Services								
43	Second Capacity	D62NLL		200,858	150,358	50,500	4,176	46,323	0
44	Second Customer	C62NL		228,711	216,881	11,829	7,586	4,243	0
43	Total Services	C62NL	369	429,568	367,239	62,329	11,762	50,566	0
44	Meters	C12WM	370	222,506	175,745	46,288	16,674	29,614	473
45	Street Lighting	Dir Assign	373	70,504	0	0	0	0	70,504
46	**Total Distribution**			4,744,230	3,128,997	1,472,628	192,973	1,279,656	142,605
47	**General & Common Plant**	PTD	303, 389-399	2,339,416	982,764	1,337,167	73,992	1,263,175	19,485
48	Prelim Elec Plant			23,505,685	9,874,489	13,435,419	743,450	12,691,969	195,777
49	TBT Investment	NEPIS		0	0	0	0	0	0
50	**Elec Plant in Serv**			23,505,685	9,874,489	13,435,419	743,450	12,691,969	195,777

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Accum Deprec; Net Plant

				1=2+3+6	2	3=4+5	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		1,529,606	610,243	919,364	42,713	876,650	0
2	Decom Int Peaking	D10S		0	0	0	0	0	0
3	Decom Int Baseload	E8760		0	0	0	0	0	0
4	Nuclear Fuel	E8760		2,566,673	811,722	1,745,849	76,574	1,669,274	9,102
5	Base Load	E8760		2,999,908	948,735	2,040,535	89,500	1,951,035	10,638
6	Total		108,111,115,120.5	7,096,188	2,370,700	4,705,747	208,787	4,496,960	19,741
	Transmission								
7	Gen Step Up Base	E8760		14,610	4,621	9,938	436	9,502	52
8	Gen Step Up Peak	D10S		16,795	6,700	10,094	469	9,625	0
9	Total Gen Step Up			31,405	11,321	20,032	905	19,128	52
10	Bulk Transmission	D10S		847,996	338,311	509,684	23,680	486,005	0
11	Distrib Function	D60Sub		0	0	0	0	0	0
12	Direct Assign	Dir Assign		2,504	0	2,504	0	2,504	0
13	Total		108,111,115,120.5	881,905	349,632	532,221	24,585	507,636	52
	Distribution								
14	Generat Step Up	STRATH		1,751	580	1,167	52	1,115	5
15	Bulk Transmission	D10S		616	246	370	17	353	0
16	Distrib Function	D60Sub		246,558	102,198	142,888	7,357	135,531	1,472
17	Direct Assign	Dir Assign		6,369	0	6,369	0	6,369	0
18	Total Substations			255,295	103,024	150,794	7,425	143,368	1,477
19	Overhead Lines	POL		401,183	263,039	117,712	16,506	101,206	20,431
20	Underground	PUL		539,328	394,302	142,911	23,714	119,198	2,115
21	Line Transformers	P68		179,587	127,996	50,935	9,075	41,860	656
22	Services	P69		201,655	172,396	29,259	5,522	23,738	0
23	Meters	C12WM		58,769	46,418	12,226	4,404	7,822	125
24	Street Lighting	P73		8,386	0	0	0	0	8,386
25	Total		108,111,115,120.5	1,644,203	1,107,175	503,837	66,646	437,191	33,192
26	**General & CommonPlant**	PTD	108,111,115,120.5	1,157,461	486,237	661,584	36,609	624,975	9,640
27	**Total Accum Depr**			10,779,757	4,313,744	6,403,388	336,626	6,066,762	62,624
28	**Net Elec Plant**			12,725,928	5,560,745	7,032,031	406,823	6,625,207	133,153
29	**Net Plant w/ TBT**			12,725,928	5,560,745	7,032,031	406,823	6,625,207	133,153
	Subtractions: Accum Defer Inc Tax								
	Production								
30	Peaking Plant	D10S		325,762	129,964	195,798	9,097	186,701	0
31	Base Load	E8760		969,565	306,629	659,497	28,926	630,571	3,438
32	Nuclear Fuel	E8760		(9,337)	(2,953)	(6,351)	(279)	(6,072)	(33)
33	Total		190,281,282,283	1,285,991	433,641	848,945	37,744	811,200	3,405
	Transmission								
34	Gen Step Up Base	E8760		18,616	5,887	12,662	555	12,107	66
35	Gen Step Up Peak	D10S		3,660	1,460	2,200	102	2,098	0
36	Total Gen Step Up			22,276	7,348	14,862	658	14,205	66
37	Bulk Transmission	D10S		734,261	292,936	441,324	20,504	420,821	0
38	Distrib Function	D60Sub		0	0	0	0	0	0
39	Direct Assign	Dir Assign		1,516	0	1,516	0	1,516	0
40	Total		281,282,283	758,053	300,284	457,703	21,161	436,542	66
	Distribution								
41	Generat Step Up	STRATH		233	77	155	7	148	1
42	Bulk Transmission	D10S		240	96	144	7	138	0
43	Distrib Function	D60Sub		112,310	46,553	65,087	3,351	61,736	671
44	Direct Assign	Dir Assign		2,489	0	2,489	0	2,489	0
45	Total Substations			115,273	46,726	67,876	3,365	64,511	671
46	Overhead Lines	POL		144,487	94,735	42,394	5,945	36,450	7,358
47	Underground	PUL		224,522	164,147	59,494	9,872	49,622	881
48	Line Transformers	P68		56,113	39,993	15,915	2,835	13,079	205
49	Services	P69		19,568	16,729	2,839	536	2,303	0
50	Meters	C12WM		9,608	7,589	1,999	720	1,279	20
51	Street Lighting	P73		13,482	0	0	0	0	13,482
52	Total		281,282,283	583,054	369,919	190,517	23,273	167,244	22,618
53	**General & Common Plant**	PTD	281,282,283	144,981	60,905	82,868	4,586	78,283	1,208
54	**Total Deferred Tax**			2,772,078	1,164,749	1,580,033	86,764	1,493,270	27,296
55	Net Operating Loss (NOL) Carry F	NEPIS		(745,797)	(325,885)	(412,109)	(23,842)	(388,267)	(7,803)
56	Non-Plant Related	LABOR		60,865	25,868	34,400	2,071	32,329	597
57	**Accum Def W/ Adj**			2,087,146	864,731	1,202,324	64,993	1,137,331	20,090

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Additions: CWIP, Etc; Rate Base

				1=2+3+6	2	3=4+5	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		190,416	75,967	114,449	5,317	109,131	0
2	Base Load	E8760		(29,030)	(9,181)	(19,746)	(866)	(18,880)	(103)
3	Nuclear Fuel	E8760		81,333	25,722	55,323	2,426	52,896	288
4	Total		107	242,718	92,508	150,025	6,878	143,147	185
	Transmission								
5	Gen Step Up Base	E8760		0	0	0	0	0	0
6	Gen Step Up Peak	D10S		0	0	0	0	0	0
7	Total Gen Step Up			0	0	0	0	0	0
8	Bulk Transmission	D10S		85,837	34,245	51,592	2,397	49,195	0
9	Distrib Function	D60Sub		0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0
11	Total		107	85,837	34,245	51,592	2,397	49,195	0
	Distribution								
12	Generat Step Up	STRATH		0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0
14	Distrib Function	D60Sub		20,548	8,517	11,908	613	11,295	123
15	Direct Assign	Dir Assign		70	0	70	0	70	0
16	Total Substations			20,618	8,517	11,978	613	11,365	123
17	Overhead Lines	POL		21,223	13,915	6,227	873	5,354	1,081
18	Underground	PUL		35,760	26,144	9,476	1,572	7,903	140
19	Line Transformers	P68		(18,982)	(13,529)	(5,384)	(959)	(4,424)	(69)
20	Services	P69		12,304	10,519	1,785	337	1,448	0
21	Meters	C12WM		0	0	0	0	0	0
22	Street Lighting	P73		191	0	0	0	0	191
23	Total		107	71,114	45,566	24,082	2,436	21,646	1,465
24	**General & Common Plant**	PTD	107	106,885	44,901	61,093	3,381	57,713	890
25	**Total CWIP**			506,554	217,221	286,793	15,092	271,701	2,541
26	Fuel Inventory	E8760	151,152	69,767	22,064	47,456	2,081	45,374	247
	Materials & Supplies								
27	Production	P10		137,834	46,480	90,990	4,045	86,944	365
28	Trans & Distr	TD		16,867	9,119	7,468	589	6,878	280
29	Total		154	154,701	55,599	98,457	4,635	93,822	645
	Prepayments								
30	Miscellaneous	NEPIS		116,242	50,793	64,232	3,716	60,516	1,216
31	Fuel	E8760		0	0	0	0	0	0
32	Insurance	NEPIS	135,143,184,186,232	0	0	0	0	0	0
33	Total		235,252,165	116,242	50,793	64,232	3,716	60,516	1,216
34	Non-Plant Assets & Liab	LABOR	190,283,	123,255	52,383	69,662	4,194	65,468	1,210
35	Working Cash	PT0	calculated	(163,615)	(74,279)	(87,621)	(5,315)	(82,306)	(1,715)
36	**Total Additions**			806,904	323,781	478,979	24,403	454,576	4,144
37	**Total Rate Base**			11,445,687	5,019,795	6,308,685	366,233	5,942,452	117,207
38	**Common Rate Base (@ 52.50%)**			6,008,985.5	2,635,392	3,312,060	192,272	3,119,787	61,533

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Operating Rev (Cal Month)

				1=2+3+6	2	3=4+5	4	5	6
	Retail Revenue	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Present Rate Revenue	R01; (calc)	440, 442,444,445	3,214,206	1,246,213	1,941,315	109,752	1,831,563	26,677
2	Proposed Rate Revenue	PROREV; (calc)		3,758,453	1,485,473	2,240,667	124,860	2,115,807	32,313
3	Equal Rate Revenue			3,758,453	1,517,670	2,207,357	120,484	2,086,873	33,426
	Other Retail Revenue								
4	Interdepartmental	R01; R02	448	625	242	378	21	356	5
5	Gross Earnings Tax	R01; R02	408	0	0	0	0	0	0
6	CIP Adjustment to Program Costs	E99XCIP	456	0	0	0	0	0	0
7	**Tot Other Retail Rev**			625	242	378	21	356	5
	Other Operating Revenue								
8	Interchg Prod Capacity	P10	456	453,563	152,948	299,413	13,312	286,101	1,201
9	Interchg Prod Energy	E8760	456	0	0	0	0	0	0
10	Interchg Tr Bulk Supply	D10S	456	0	0	0	0	0	0
11	Dist Int Sales; Oth Serv	E8760	412,451,456	0	0	0	0	0	0
12	Dist Overhd Line Rent	POL	454	4,765	3,124	1,398	196	1,202	243
13	Connection Charges	C11	451	1,730	1,520	175	112	63	35
14	Sales For Resale	E8760	447	0	0	0	0	0	0
15	Joint Op Agree-Other PSCo Rev	D10S	456	0	0	0	0	0	0
16	Misc Ancillary Trans Rev	D10S		221,985	88,562	133,423	6,199	127,225	0
17	MISO	D10S	456	(92,894)	(37,061)	(55,834)	(2,594)	(53,240)	0
18	Other	D10S	451,456,457	14,868	5,931	8,936	415	8,521	0
19	Late Pay Chg - Pres	R16C; R02		5,215	4,431	782	157	625	3
20	**Tot Other Op - Pres**		450	609,232	219,456	388,294	17,797	370,497	1,482
21	Incr Misc Serv - Prop	C62NL		892	846	46	30	17	0
22	Incr Inter-Dept'l - Prop	R01; R02		101	39	61	3	58	1
23	Incr Late Pay - Prop	(R16C); R02		883	750	132	27	106	1
	Tot Incr Other Op			1,876	1,635	240	60	180	1
24	**Tot Other Op - Prop**			611,108	221,091	388,534	17,857	370,677	1,483
25	**Tot Oper Rev - Pres**			3,824,063	1,465,911	2,329,987	127,571	2,202,416	28,164
26	**Tot Oper Rev - Prop**			4,370,186	1,706,806	2,629,579	142,739	2,486,840	33,801
	Tot Oper Rev - Eql			4,370,186	1,739,003	2,596,269	138,362	2,457,906	34,914

Operating & Maint (Pg 1 of 2)

	Production Expen								
27	**Fuel**	E8760	501,518,547	616,088	194,841	419,063	18,380	400,682	2,185
	Purchased Power								
28	Purchases: Cap Peak	D10S		106,050	42,309	63,741	2,961	60,780	0
29	Purchases: Cap Base	D10S		39,463	15,744	23,719	1,102	22,617	0
30	Purchases: Demand		555	145,513	58,053	87,460	4,063	83,397	0
31	Purchases: Other Energy	E8760	555	380,791	120,427	259,014	11,361	247,653	1,350
32	Tot Non-Assoc Purch			526,305	178,480	346,474	15,424	331,050	1,350
33	Interchg Agr Capacity	P10WoN	557	54,688	18,761	35,796	1,598	34,198	131
34	Interchg Agr Energy	E8760	557	13,393	4,236	9,110	400	8,711	47
35	Tot Wis Interchg Purch			68,082	22,997	44,906	1,997	42,909	179
36	**Tot Purchased Power**			594,386	201,477	391,380	17,421	373,959	1,529
	Other Production		500,502,505-507 509-514,517-519,520, 523-525,528-532,535, 539,543-546,548-550 552-554,556,557 575.1-575.8						
37	Capacity Related	D10S		98,067	39,124	58,943	2,738	56,204	0
38	Energy Related	E8760		336,808	106,517	229,096	10,048	219,048	1,194
39	Total Other Produc	22.55%		434,874.201	145,641	288,039	12,787	275,252	1,194
40	**Total Production**			1,645,349	541,959	1,098,482	48,589	1,049,893	4,908
41	**Transmission Exp**	D10S	560-563, 565-568 570-573	265,940	106,098	159,842	7,426	152,416	0

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Operating & Maint (Pg 2 of 2)

				1=2+3+6	2	3=4+5	4	5	6
	Distribution Expen	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Supervision & Eng'rg	ZDTS	580,590	10,899	7,145	3,268	473	2,796	485
2	Load Dispatching	T20D80	581	841	346	491	25	466	4
3	Substations	P61	582,591,592	5,848	2,364	3,449	170	3,279	34
4	Overhead Lines	POL	583,593	56,047	36,748	16,445	2,306	14,139	2,854
5	Underground Lines	PUL	584, 594	21,319	15,586	5,649	937	4,712	84
6	Line Transformers	P68	595	31	22	9	2	7	0
7	Meters	C12WM	586,597,598	1,828	1,444	380	137	243	4
8	Customer Install'n	OXDTS	587	2,638	1,701	794	108	686	143
9	Street Lighting	Dir Assign	585,596	1,780	0	0	0	0	1,780
10	Miscellaneous	OXDTS	588	21,418	13,812	6,446	874	5,572	1,160
11	Rents (Pole Attachmts)	POL	589	3,882	2,545	1,139	160	979	198
12	**Total Distribution**			126,532	81,714	38,072	5,191	32,881	6,746
13	**Customer Accounting**	C11WA	901-905	45,999	38,611	7,242	3,700	3,542	147
14	**Sales, Econ Dvlp & Other**	R01	912	8,297	3,217	5,011	283	4,728	69
	Admin & General								
15	Salaries	LABOR	920	87,458	37,170	49,430	2,976	46,454	858
16	Office Supplies	OXTS	921	62,504	23,271	38,856	1,964	36,892	377
17	Admin Transfer Credit	OXTS	922	(63,086)	(23,487)	(39,217)	(1,982)	(37,235)	(381)
18	Outside Services	LABOR	923	19,677	8,363	11,121	669	10,452	193
19	Property Insurance	NEPIS	924	8,194	3,581	4,528	262	4,266	86
20	Pensions & Benefits	LABOR	926	61,605	26,182	34,818	2,096	32,722	605
21	Injuries & Claims	LABOR	925	15,723	6,682	8,886	535	8,352	154
22	Regulatory Exp	R01; R02	928	6,548	2,539	3,955	224	3,731	54
23	General Advertising	OXTS	930.1	193	72	120	6	114	1
24	Contributions	OXTS		0	0	0	0	0	0
25	Misc General Exp	OXTS	929, 930.2	836	311	519	26	493	5
26	Rents	OXTS	931	42,478	15,815	26,407	1,335	25,072	256
27	Maint of General Plant	OXTS	935	1,129	420	702	35	666	7
28	Total			243,259	100,918	140,125	8,146	131,979	2,216
	Cust Service & Info								
29	Cust Assist Exp - Non-CIP	C11P10	908	1,108	673	422	52	370	13
30	CIP Total	E99XCIP	908	131,762.100	42,766	88,389	4,020	84,369	607
31	Instructional Advertising	C11P10	909	783	476	298	37	261	9
32	Total			133,653	43,915	89,109	4,109	85,000	629
33	Amortizations	LABOR		55,267	23,489	31,236	1,880	29,356	542
34	**Total O&M Expense**			2,524,296	939,920	1,569,118	79,324	1,489,795	15,257

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Book Depreciation

				1=2+3+6	2	3=4+5	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		133,044	53,078	79,965	3,715	76,250	0
2	Base Load	E8760		325,323	102,885	221,285	9,706	211,579	1,154
3	Total		403,413	458,367	155,963	301,250	13,421	287,829	1,154
	Transmission								
4	Gen Step Up Base	E8760		2,179	689	1,482	65	1,417	8
5	Gen Step Up Peak	D10S		1,279	510	769	36	733	0
6	Total Gen Step Up			3,458	1,199	2,251	101	2,150	8
7	Bulk Transmission	D10S		76,885	30,674	46,211	2,147	44,064	0
8	Distrib Function	D60Sub		0	0	0	0	0	0
9	Direct Assign	Dir Assign		173	0	173	0	173	0
10	Total		403,413	80,516	31,873	48,635	2,248	46,387	8
	Distribution								
11	Generat Step Up	STRATH		71	24	48	2	45	0
12	Bulk Transmission	D10S		41	16	25	1	23	0
13	Distrib Function	D60Sub		17,720	7,345	10,269	529	9,741	106
14	Direct Assign	Dir Assign		424	0	424	0	424	0
15	Total Substations		403,413	18,256	7,385	10,765	532	10,233	106
16	Overhead Lines	POL		39,281	25,755	11,525	1,616	9,909	2,000
17	Underground	PUL		39,783	29,085	10,542	1,749	8,792	156
18	Line Transformers	P68		11,620	8,282	3,296	587	2,708	42
19	Services	P69		22,728	19,431	3,298	622	2,675	0
20	Meters	C12WM		10,590	8,365	2,203	794	1,409	23
21	Street Lighting	P73		4,141	0	0	0	0	4,141
22	Total		403,413	146,398	98,301	41,628	5,900	35,728	6,469
23	**General & Common Plant**	PTD	403,413	163,833	68,825	93,644	5,182	88,462	1,365
24	**Total Book Deprec**		403,404	849,115	354,962	485,158	26,751	458,407	8,995

Real Estate & Property Tax

	Production								
25	Peaking Plant	D10S		31,680	12,639	19,041	885	18,156	0
26	Base Load	E8760		66,076	20,897	44,945	1,971	42,974	234
27	Total		408.1	97,756	33,536	63,986	2,856	61,130	234
	Transmission								
28	Gen Step Up Base	E8760		1,775.0600	561	1,207	53	1,154	6
29	Gen Step Up Peak	D10S		472.8147	189	284	13	271	0
30	Total Gen Step Up			2,247.8747	750	1,492	66	1,425	6
31	Bulk Transmission	D10S		48,617.5611	19,396	29,221	1,358	27,864	0
32	Distrib Function	D60Sub		0	0	0	0	0	0
33	Direct Assign	Dir Assign		109	0	109	0	109	0
34	Total		408.1	50,974.580	20,146	30,822	1,424	29,398	6
	Distribution								
35	Generat Step Up	STRATH		43	14	29	1	28	0
36	Bulk Transmission	D10S		25	10	15	1	14	0
37	Distrib Function	D60Sub		10,918	4,525	6,327	326	6,001	65
38	Direct Assign	Dir Assign		266	0	266	0	266	0
39	Total Substations			11,252	4,550	6,637	328	6,310	65
40	Overhead Lines	POL		16,447	10,784	4,826	677	4,149	838
41	Underground	PUL		23,424	17,125	6,207	1,030	5,177	92
42	Line Transformers	P68		5,952	4,242	1,688	301	1,387	22
43	Services	P69		6,096	5,212	885	167	718	0
44	Meters	C12WM		3,158	2,494	657	237	420	7
45	Street Lighting	P73		1,001	0	0	0	0	1,001
46	Total		408.1	67,330	44,406	20,899	2,739	18,161	2,024
47	**General & Common Plant**	PTD	408.1	0	0	0	0	0	0
48	**Tot Rl Est & Pr Tax**			216,060	98,088	115,708	7,018	108,689	2,264
49	Gross Earnings Tax	R01; R02		0	0	0	0	0	0
50	Payroll Taxes	LABOR		27,435	11,660	15,506	933	14,573	269
51	**Tot Non-Inc Taxes**			243,495	109,748	131,214	7,952	123,262	2,534

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Northern States Power Company
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Provision For Defer Inc Tax

		Alloc	FERC Accounts	1=2+3+6 MN	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5 Demand	6 St Ltg
	Production								
1	Peaking Plant	D10S		24,273	9,684	14,589	678	13,911	0
2	Nuclear Fuel	E8760		1,377	436	937	41	896	5
3	Base Load	E8760		(6,878)	(2,175)	(4,678)	(205)	(4,473)	(24)
4	Total		410, 411	18,773	7,944	10,848	514	10,334	(20)
	Transmission								
5	Gen Step Up Base	E8760		840	266	571	25	546	3
6	Gen Step Up Peak	D10S		202	80	121	6	116	0
7	Total Gen Step Up			1,042	346	693	31	662	3
8	Bulk Transmission	D10S		8,731	3,483	5,248	244	5,004	0
9	Distrib Function	D60Sub		0	0	0	0	0	0
10	Direct Assign	Dir Assign		15	0	15	0	15	0
11	Total		410, 411	9,788	3,829	5,955	274	5,681	3
	Distribution								
12	Generat Step Up	STRATH		(40)	(13)	(27)	(1)	(26)	(0)
13	Bulk Transmission	D10S		(6)	(2)	(3)	(0)	(3)	0
14	Distrib Function	D60Sub		621	257	360	19	341	4
15	Direct Assign	Dir Assign		(45)	0	(45)	0	(45)	0
16	Total Substations			530	242	285	17	268	4
17	Overhead Lines	POL		2,288	1,500	671	94	577	117
18	Underground	PUL		(2,160)	(1,580)	(572)	(95)	(477)	(8)
19	Line Transformers	P68		(1,383)	(986)	(392)	(70)	(322)	(5)
20	Services	P69		(318)	(272)	(46)	(9)	(37)	0
21	Meters	C12WM		33	26	7	2	4	0
22	Street Lighting	P73		(468)	0	0	0	0	(468)
23	Total		410, 411	(1,478)	(1,069)	(48)	(60)	12	(361)
24	**General & Common Plant**	PTD	410, 411	5,890	2,474	3,366	186	3,180	49
25	**Net Operating Loss (NOL) Carry**	NEPIS		(166,121)	(72,588)	(91,794)	(5,311)	(86,484)	(1,738)
26	**Non - Plant Related**	LABOR	410, 411	14,633	6,219	8,270	498	7,773	144
27	**Tot Prov For Defer**			(118,516)	(53,191)	(63,402)	(3,898)	(59,504)	(1,923)

Inv Tax Credit; Total Oper Exp

		Alloc	FERC Accounts	MN	Res	C&I Tot	Sm Non-D	Demand	St Ltg
	Production								
28	Peaking Plant	D10S		(275)	(110)	(166)	(8)	(158)	0
29	Base Load	E8760		(523)	(166)	(356)	(16)	(340)	(2)
30	Total		411	(799)	(275)	(522)	(23)	(498)	(2)
	Transmission								
31	Gen Step Up Base	E8760		0	0	0	0	0	0
32	Gen Step Up Peak	D10S		0	0	0	0	0	0
33	Total Gen Step Up			0	0	0	0	0	0
34	Bulk Transmission	D10S		(150)	(60)	(90)	(4)	(86)	0
35	Distrib Function	D60Sub		0	0	0	0	0	0
36	Direct Assign	Dir Assign		0	0	0	0	0	0
37	Total		411	(150)	(60)	(90)	(4)	(86)	0
	Distribution								
38	Generat Step Up	STRATH		0	0	0	0	0	0
39	Bulk Transmission	D10S		0	0	0	0	0	0
40	Distrib Function	D60Sub		0	0	0	0	0	0
41	Direct Assign	Dir Assign		0	0	0	0	0	0
42	Total Substations			0	0	0	0	0	0
43	Overhead Lines	POL		(264)	(173)	(77)	(11)	(66)	(13)
44	Underground	PUL		0	0	0	0	0	0
45	Line Transformers	P68		0	0	0	0	0	0
46	Services	P69		0	0	0	0	0	0
47	Meters	C12WM		0	0	0	0	0	0
48	Street Lighting	P73		0	0	0	0	0	0
49	Total		411	(264)	(173)	(77)	(11)	(66)	(13)
50	**General & Common Plant**	PTD	411	(7)	(3)	(4)	(0)	(4)	(0)
51	**Net Inv Tax Credit**			(1,219)	(511)	(693)	(39)	(655)	(15)
28	TBT Misc Net Exp	NEPIS		0	0	0	0	0	0
52	**Total Operating Exp**			**3,497,171**	**1,350,929**	**2,121,395**	**110,090**	**2,011,305**	**24,847**
53A	**Pres Op Inc Before Inc Tax**			**326,892**	**114,982**	**208,593**	**17,481**	**191,112**	**3,317**
53B	**Prop Op Inc Before Inc Tax**			**873,015**	**355,877**	**508,184**	**32,649**	**475,535**	**8,954**

2023 Class Cost of Service Study ($000)

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Tax Deprec; Inc Tax & Return

				1=2+3+6	2	3=4+5	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		247,359	98,685	148,674	6,907	141,767	0
2	Nuclear Fuel	E8760		99,139	31,353	67,434	2,958	64,477	352
3	Base Load	E8760		375,837	118,860	255,644	11,213	244,431	1,333
4	Total		tax books	722,334	248,898	471,752	21,078	450,674	1,684
	Transmission								
5	Gen Step Up Base	E8760		5,902	1,866	4,014	176	3,838	21
6	Gen Step Up Peak	D10S		1,496	597	899	42	858	0
7	Total Gen Step Up			7,398	2,463	4,914	218	4,696	21
8	Bulk Transmission	D10S		119,181	47,548	71,633	3,328	68,305	0
9	Distrib Function	D60Sub		0	0	0	0	0	0
10	Direct Assign	Dir Assign		249	0	249	0	249	0
11	Total		tax books	126,828	50,011	76,796	3,546	73,250	21
	Distribution								
12	Generat Step Up	STRATH		0	0	0	0	0	0
13	Bulk Transmission	D10S		20	8	12	1	11	0
14	Distrib Function	D60Sub		21,867	9,064	12,672	652	12,020	131
15	Direct Assign	Dir Assign		263	0	263	0	263	0
16	Total Substations			22,149	9,071	12,947	653	12,294	131
17	Overhead Lines	POL		48,262	31,643	14,161	1,986	12,175	2,458
18	Underground	PUL		50,015	36,566	13,253	2,199	11,054	196
19	Line Transformers	P68		15,419	10,990	4,373	779	3,594	56
20	Services	P69		15,180	12,977	2,203	416	1,787	0
21	Meters	C12WM		4,325	3,416	900	324	576	9
22	Street Lighting	P73		3,066	0	0	0	0	3,066
23	Total		tax books	158,417	104,664	47,836	6,357	41,480	5,917
24	**General & Common Plant**	PTD	tax books	240,011	100,826	137,186	7,591	129,594	1,999
25	Net Operating Loss (NOL) Carry F	NEPIS		0	0	0	0	0	0
26	**Total Tax Deprec**			1,247,590	504,399	733,570	38,572	694,999	9,621
27	Interest Expense		427,431	219,757.18	96,380	121,127	7,032	114,095	2,250
28	Other Tax Timing Differ	LABOR		9,917	4,215	5,605	337	5,267	97
29	Meals & Enter	LABOR		1,160	493	656	39	616	11
30	Total Tax Deductions			1,478,425	605,487	860,958	45,980	814,978	11,980
	Inc Tax Additions								
31	Book Depreciation			849,114.694	354,962	485,158	26,751	458,407	8,995
32	Deferred Inc Tax & ITC			(119,734.914)	(53,702)	(64,095)	(3,937)	(60,158)	(1,939)
33	Nuclear Fuel Book Burn	E8760		97,190.704	30,737	66,109	2,900	63,209	345
34	Nuclear Fuel Disposal	E8760		0.000	0	0	0	0	0
34	Tax Capitalized Leases	PTD		39,291.751	16,506	22,458	1,243	21,216	327
34	Meals & Entertainment	LABOR		0.000	0	0	0	0	0
14	Connect Fees, Cus Adv	C11		0.000	0	0	0	0	0
35	Avoided Tax Interest	RTBASE		21,857.434	9,586	12,047	699	11,348	224
36	Total Tax Additions			887,719.670	358,090	521,678	27,656	494,022	7,952
37	**Total Inc Tax Adjustments**			(590,705)	(247,397)	(339,280)	(18,324)	(320,956)	(4,028)
38A	**Pres Taxable Net Income**			(263,813)	(132,415)	(130,687)	(843)	(129,844)	(711)
38B	**Prop Taxable Net Income**			282,310	108,480	168,904	14,325	154,580	4,926
39A	Pres Fed & State Inc Tax			(85,432)	(42,272)	(42,857)	(550)	(42,307)	(303)
39B	Prop Fed & State Inc Tax			71,535	26,966	43,252	3,810	39,442	1,317
40A	Pres Preliminary Return	(total); BASE		412,324	157,254	251,450	18,031	233,419	3,620
40B	Prop Preliminary Return	(total); BASE		801,480	328,911	464,933	28,839	436,093	7,637
41	Total AFUDC			31,766	13,587	18,076	941	17,135	103
42A	**Present Total Return**			444,090	170,841	269,526	18,972	250,554	3,723
42B	**Proposed Total Return**			833,246	342,498	483,008	29,780	453,228	7,740
43A	**Pres % Return on Rate Base**			3.88%	3.40%	4.27%	5.18%	4.22%	3.18%
43B	**Prop % Return on Rate Base**			7.28%	6.82%	7.66%	8.13%	7.63%	6.60%
44A	**Present Common Return**			224,333	74,461	148,399	11,940	136,458	1,472
44B	**Proposed Common Return**			613,489	246,118	361,882	22,749	339,133	5,489
45A	**Pres % Ret on Common Rt Base**			3.73%	2.83%	4.48%	6.21%	4.37%	2.39%
45B	**Prop % Ret on Common Rt Base**			10.21%	9.34%	10.93%	11.83%	10.87%	8.92%

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Allow For Funds Used During Constr

		Alloc	FERC Accounts	1=2+3+6 MN	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5 Demand	6 St Ltg
	Production								
1	Peaking Plant	D10S		14,859	5,928	8,931	415	8,516	0
2	Nuclear Fuel	E8760		5,305	1,678	3,608	158	3,450	19
3	Base Load	E8760		(4,668)	(1,476)	(3,175)	(139)	(3,036)	(17)
4	Total		419.1,432	15,495	6,129	9,364	434	8,930	2
	Transmission								
5	Gen Step Up Base	E8760		0	0	0	0	0	0
6	Gen Step Up Peak	D10S		0	0	0	0	0	0
7	Total Gen Step Up			0	0	0	0	0	0
8	Bulk Transmission	D10S		5,695	2,272	3,423	159	3,264	0
9	Distrib Function	D60Sub		0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0
11	Total		419.1,432	5,695	2,272	3,423	159	3,264	0
	Distribution								
12	Generat Step Up	STRATH		0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0
14	Distrib Function	D60Sub		1,307	542	758	39	719	8
15	Direct Assign	Dir Assign		4	0	4	0	4	0
16	Total Substations			1,312	542	762	39	723	8
17	Overhead Lines	POL		607	398	178	25	153	31
18	Underground	PUL		992	725	263	44	219	4
19	Line Transformers	P68		0	0	0	0	0	0
20	Services	P69		671	574	97	18	79	0
21	Meters	C12WM		25	20	5	2	3	0
22	Street Lighting	P73		0	0	0	0	0	0
23	Total		419.1,432	3,606	2,258	1,305	128	1,178	43
24	**General & Common Plant**	PTD	419.1,432	6,970	2,928	3,984	220	3,763	58
25	**Total AFUDC**			31,766	13,587	18,076	941	17,135	103

Labor Allocator

		Alloc	FERC Accounts	MN	Res	C&I Tot	Sm Non-D	Demand	St Ltg
	Production								
26	Other Prod - Cap	D10S		69,498	27,727	41,772	1,941	39,831	0
27	Other Prod - Ene	E8760		144,958	45,844	98,600	4,325	94,275	514
28	Total		500 through 557	214,456	73,570	140,372	6,265	134,106	514
	Transmission								
29	Stepup Subtrans	P5161A		749	250	497	22	475	2
30	Bulk Power Subs	D10S		16,190	6,459	9,731	452	9,279	0
31	Total		560 through 571	16,939	6,709	10,228	474	9,754	2
	Distribution								
32	Superv & Eng	ZDTS	580, 590	8,455	5,543	2,535	367	2,169	377
33	Load Dispatch	D10S	581	(88)	(35)	(53)	(2)	(50)	0
34	Substation	P61	582, 592	3,333	1,348	1,966	97	1,869	19
35	Overhead Lines	POL	583, 593	13,659	8,956	4,008	562	3,446	696
36	Underground Lines	PUL	584, 594	10,084	7,373	2,672	443	2,229	40
37	Line Transformer	P68	595	29	20	8	1	7	0
38	Meter	C12WM	586, 597	3,824	3,020	796	287	509	8
39	Cust Installation	ZDTS	587	2,441	1,600	732	106	626	109
40	Street Lighting	P73	585, 596	533	0	0	0	0	533
41	Miscellaneous	OXDTS	588	10,636	6,859	3,201	434	2,767	576
42	Total			52,905	34,684	15,865	2,295	13,571	2,356
43	**Cust Accounting**	C11WA	901,902,903,904,905	13,095	10,992	2,062	1,053	1,008	42
44	**Sales Expense**	C11P10	912	1,565	951	596	74	522	18
45	**Admin & General**	LABOR	920,921,922,923,924,	151,851	64,537	85,824	5,167	80,657	1,490
46	**Service & Inform**	C11P10	908, 909	836	508	318	39	279	10
47	**Labor**			451,648	191,951	255,265	15,367	239,898	4,432

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PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

			1=2+3+6	2	3=4+5	4	5	
INTERNAL ALLOCATORS		Intern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	50% Cus, 50% Prod Plt	C11P10	100.00%	60.78%	38.07%	4.70%	33.36%	1.15%
2	Peaking Plant Capacity	D10S	100.00%	39.90%	60.10%	2.79%	57.31%	0.00%
3	57% Dmd; 43% Energy: Sales & E	D57E43	100.00%	31.63%	68.02%	2.98%	65.04%	0.35%
4	40% Dmd; 60% Energy: CIP	D40E60	100.00%	31.63%	68.02%	2.98%	65.04%	0.35%
5	20%D10T; 80%D60Sub	T20D80	100.00%	41.14%	58.38%	2.95%	55.44%	0.48%
6	Labor w/o (or w/) A&G	LABOR	100.00%	42.50%	56.52%	3.40%	53.12%	0.98%
7	Net Plant In Service	NEPIS	100.00%	43.70%	55.26%	3.20%	52.06%	1.05%
8	Dis O&M w/o Sup & Misc	OXDTS	100.00%	64.49%	30.10%	4.08%	26.02%	5.41%
9	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	100.00%	37.23%	62.17%	3.14%	59.02%	0.60%
10	Production Plant	P10	100.00%	33.72%	66.01%	2.94%	63.08%	0.26%
11	Production Plant Wo Nuclear	P10WoN	100.00%	34.31%	65.45%	2.92%	62.53%	0.24%
12	Total P51 & P61A	P5161A	100.00%	33.36%	66.36%	2.94%	63.42%	0.28%
13	Distribution Plant	P60	100.00%	65.95%	31.04%	4.07%	26.97%	3.01%
14	Distr Substn Plant	P61	100.00%	40.43%	58.99%	2.91%	56.07%	0.58%
15	Line Transformer Plant	P68	100.00%	71.27%	28.36%	5.05%	23.31%	0.37%
16	Services Plant	P69	100.00%	85.49%	14.51%	2.74%	11.77%	0.00%
17	Dist Plt Overhead Lines	POL	100.00%	65.57%	29.34%	4.11%	25.23%	5.09%
18	Real Est & Property Tax	PT0	100.00%	45.40%	53.55%	3.25%	50.31%	1.05%
19	Produc, Trans & Distrib	PTD	100.00%	42.01%	57.16%	3.16%	54.00%	0.83%
20	Dist Plt Undground Lines	PUL	100.00%	73.11%	26.50%	4.40%	22.10%	0.39%
21	Rate Base (Non-Column)	RTBASE	100.00%	43.86%	55.12%	3.20%	51.92%	1.02%
22	Stratified Hydro Baseload	STRATH	100.00%	33.10%	66.61%	2.95%	63.66%	0.29%
23	Transmission & Distrib	TD	100.00%	54.07%	44.28%	3.49%	40.78%	1.66%
24	Labor Dis w/o Sup & Eng	ZDTS	100.00%	65.56%	29.99%	4.34%	25.65%	4.45%

			1=2+3+6	2	3=4+5	4	5	6
INTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
25	Labor w/o A&G	LABOR(S)	299,797	127,414	169,441	10,200	159,241	2,942
26	Dis O&M w/o Sup, Cust Install & M	OXDTS	91,577	59,056	27,563	3,737	23,826	4,958
27	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	2,473,693	920,980	1,537,777	77,716	1,460,061	14,937
28	Total P51 & P61A	P5161A	174,077	58,073	115,517	5,124	110,393	488
29	Produc, Trans & Distrib	PTD	21,166,270	8,891,725	12,098,252	669,458	11,428,794	176,293
30	Transmission & Distrib	TD	8,622,582	4,661,799	3,817,699	301,299	3,516,400	143,084
31	Labor Dis w/o Sup & Eng, Cust In	ZDTS	42,010	27,541	12,598	1,822	10,776	1,871

2023 Class Cost of Service Study ($000)

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HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

			1=2+3+6	2	3=4+5	4	5	6
EXTERNAL ALLOCATORS		Extern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Customers - Ave Monthly	C11	100.00%	87.84%	10.12%	6.47%	3.65%	2.04%
2	Cust Acctg Wtg Factor	C11WA	100.00%	83.94%	15.74%	8.04%	7.70%	0.32%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	78.98%	20.80%	7.49%	13.31%	0.21%
4	Sec & Pri Customers	C61PS	100.00%	89.27%	10.31%	6.59%	3.72%	0.43%
5	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	100.00%	95.03%	4.63%	3.96%	0.67%	0.34%
6	C62Sec, w/o Ltg & C/I Undergrou	C62NL	100.00%	94.83%	5.17%	3.32%	1.86%	0.00%
7	Secondary Customers	C62Sec	100.00%	89.30%	10.27%	6.59%	3.68%	0.43%
8	Summer Peak Resp KW	D10S	100.00%	39.90%	60.10%	2.79%	57.31%	0.00%
9	Transmission Demand %	D10T	100.00%	38.47%	61.21%	2.93%	58.28%	0.32%
10	Winter Peak Resp KW	D10W	100.00%	36.42%	62.80%	3.13%	59.67%	0.78%
11	Alternative Production Allocator	1CP	100.00%	39.90%	60.10%	2.79%	57.31%	0.00%
12	Sec, Pri & TT, Class Coin kW @ S	D60Sub	100.00%	41.45%	57.95%	2.98%	54.97%	0.60%
13	Sec & Pri, Cl Coin kW (no Min Sy	D61PS	100.00%	36.88%	62.78%	2.50%	60.28%	0.34%
14	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	100.00%	74.83%	24.66%	2.87%	21.79%	0.51%
15	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	100.00%	74.86%	25.14%	2.08%	23.06%	0.00%
16	Sec, Class Coin kW (w/o Min Sys	D62SecL	100.00%	50.14%	49.60%	3.13%	46.47%	0.26%
17	Direct Assign Street Lighting	DASL	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%
18	On + Off Sales MWH	E8760	100.00%	31.63%	68.02%	2.98%	65.04%	0.35%
19	Street Lighting (Dir Assign)	P73	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%
20	MWh Sales Excl CIP Exempt	E99XCIP	100.00%	32.46%	67.08%	3.05%	64.031%	0.46%
21	Present Rev	R01	100.0000%	38.7720%	60.3980%	3.4146%	56.9834%	0.8300%
22	Late Fee Revenue Allocator	LateFee	100.00%	84.95%	14.99%	3.01%	11.98%	0.06%

			1=2+3+6	2	3=4+5	4	5	6
EXTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
23	Customers - B Basis	C10	1,352,981	1,207,737	139,445	89,099	50,346	5,799
24	Cust - Ave Monthly (C10-Area Lt)	C11	1,379,292	1,211,549	139,642	89,296	50,346	28,101
25	Mo Cus Wtd By Cus Acct	C11WA	1,443,387	1,211,549	227,236	116,085	111,151	4,602
26	Cust Acctg Wtg Factor	C11WAF	18.83	1.00	17.83	1.30	16.53	N/A
27	Cust-Ave Mo (C11 w/ Dir Assign S	C12	1,354,060	1,211,549	139,642	89,296	50,346	2,869
28	Mo Cus Wtd By Mtr Invest	C12WM	148,605,874	117,375,415	30,914,397	11,135,986	19,778,411	316,063
29	Meter Invest / Cust Factor	C12WMF	10,636	97	10,429	125	10,304	110
30	Sec & Pri Customers	C61PS	1,352,959	1,207,737	139,423	89,099	50,324	5,799
31	% Served by Primary Single Phase		0.0%	72.72%	0.00%	41.04%	0.00%	53.62%
32	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	924,140	878,246	42,785	36,570	6,215	3,109
33	C62Sec, w/o Ltg & C/I Undergrou	C62NL	1,273,610	1,207,737	65,873	42,244	23,629	0
34	Secondary Customers	C62Sec	1,352,472	1,207,737	138,937	89,099	49,838	5,799
35	Summer Peak Resp KW	D10S	34,453	13,745	20,708	962	19,746	0
36	Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	3,846,963	6,121,158	293,176	5,827,982	31,879
37	Winter Peak Resp KW	D10W	4,118	1,500	2,586	129	2,457	32
38	Alternative Production Allocator	1CP	34,453	13,745	20,708	962	19,746	0
39	Sec, Pri & TT, Class Coin kW @ S	D60Sub	6,039,068	2,503,189	3,499,821	180,186	3,319,635	36,057
40	Sec & Pri, Class Coin kW (w/o Mi	D61PS	5,396,425	1,989,947	3,387,953	135,021	3,252,932	18,525
41	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	1,933,887	1,447,056	476,898	55,418	421,480	9,933
42	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	11,154,742	8,350,215	2,804,527	231,942	2,572,585	0
43	Sec, Class Coin kW (w/o Min Sys	D62SecL	10,000,000	5,013,825	4,960,225	313,113	4,647,113	25,949
44	Annual Billing kW	D99	47,757.364	0	47,757	0	47,757	0
45	Summer Billing kW	D99S	17,327.495	0	17,327	0	17,327	0
46	Winter Billing kW	D99W	30,429.869	0	30,430	0	30,430	0
47	Non-Coinc Pk Second	DN-Sec	14,283,943	8,350,215	5,915,203	489,204	5,425,999	18,525
48	MWh Sales	E99	27,973,459	8,648,531	19,202,079	813,063	18,389,015	122,850
49	MWh Sales Excl CIP Exempt	E99XCIP	26,646,248	8,648,531	17,874,868	812,948	17,061,920	122,850

Northern States Power Company
Electric Utility - Minnesota
Summary of 2024 Class Cost of Service Study ($000)

UNADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	3,866,065	1,584,959	123,497	2,124,798	32,810
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	2,097	1,823	66	206	2
[3]	Unadjusted Operating Revenues (line 1 + line 2)	3,868,161	1,586,782	123,563	2,125,004	32,812
[4]	Present Rates (CCOSS page 2, line 2)	3,190,814	1,242,316	108,110	1,813,729	26,659
[5]	Unadjusted Deficiency (line 3 - line 4)	677,347	344,466	15,453	311,275	6,153
[6]	Defic / Pres (line 5 / line 4)	21.2%	27.7%	14.3%	17.2%	23.1%
[7]	**Ratio: Class % / Total %**	**1.00**	**1.31**	**0.67**	**0.81**	**1.09**

COST RESPONSIBILITIES FOR RATE DISCOUNTS

		Total	Residential	Non-Demand	Demand	Street Ltg
		[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS				
[8]	Interruptible Rate Discounts (CCOSS page 2, line 5)					
[9]	Economic Development Discount (CCOSS page 2, line 6)					
[10]	Interruptible Rate Disc Cost Allocation (CCOSS page 2, line 7)					
[11]	Economic Development Disc Cost Allocation (CCOSS page 2, line 8)					
				HIGHLY CONFIDENTIAL TRADE SECRET ENDS]		
[12]	Revenue Requirement Change (lines 10 & 11 - lines 8 & 9)	0	(1,002)	1,145	(214)	71

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[13]	Adjusted Rate Revenue Reqt (line 1 + line 12)	3,866,065	1,583,957	124,642	2,124,584	32,882
[14]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	2,097	1,823	66	206	2
[15]	Adjusted Operating Revenues (line 13 + line 14)	3,868,161	1,585,780	124,708	2,124,790	32,883
[16]	Present Rates (line 4)	3,190,814	1,242,316	108,110	1,813,729	26,659
[17]	Adjusted Deficiency (line 15 - line 16)	677,347	343,464	16,598	311,061	6,224
[18]	**Defic / Pres Rates (line 17 / line 16)**	**21.2%**	**27.6%**	**15.4%**	**17.2%**	**23.3%**
[19]	**Ratio: Class % / Total %**	**1.00**	**1.30**	**0.72**	**0.81**	**1.10**

PROPOSED REVENUE RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[20]	Proposed Rates (CCOSS page 3, line 3)	3,866,065	1,544,588	127,815	2,161,070	32,591
[21]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	2,097	1,823	66	206	2
[22]	Proposed Operating Revenues (line 20 + line 21)	3,868,161	1,546,411	127,882	2,161,276	32,592
[23]	Proposed Increase (line 22 - line 16)	677,347	304,095	19,771	347,547	5,933
[24]	Difference / Pres (line 23 / line 16)	21.2%	24.5%	18.3%	19.2%	22.3%
[25]	**Ratio: Class % / Total %**	**1.00**	**1.15**	**0.86**	**0.90**	**1.05**

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HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - Minnesota
2024 Class Cost of Service Study ($000)

Rate Base

			1=2+3+6	2	3=4+5	4	5	6
	Plant In Service	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Production		12,749,709	4,312,739	8,404,807	368,603	8,036,203	32,163
2	Transmission		4,067,600	1,594,765	2,472,368	112,602	2,359,765	468
3	Distribution		5,124,628	3,412,083	1,572,243	208,494	1,363,749	140,302
4	General		2,578,288	1,095,098	1,462,869	81,043	1,381,826	20,321
5	Common		0	0	0	0	0	0
6	Total Plant In Service		24,520,225	10,414,685	13,912,287	770,743	13,141,543	193,254
7	Production		7,535,471	2,517,213	4,997,850	218,535	4,779,315	20,408
8	Transmission		948,447	372,772	575,616	26,214	549,402	58
9	Distribution		1,741,690	1,180,416	527,534	69,840	457,693	33,740
10	General		1,343,339	570,568	762,184	42,225	719,959	10,587
11	Common		0	0	0	0	0	0
12	Total Depreciation Reserve		11,568,947	4,640,969	6,863,184	356,814	6,506,369	64,794
13	**Net Plant In Service**		12,951,278	5,773,715	7,049,103	413,929	6,635,174	128,460
14	Deducts: Accum Defer Inc Tax		1,954,203	801,606	1,134,838	59,710	1,075,128	17,760
15	Constr Work In Progress		616,842	261,510	352,875	18,065	334,810	2,457
16	Fuel Inventory		69,767	22,110	47,416	2,049	45,367	242
17	Materials & Supplies		154,701	55,811	98,284	4,574	93,710	606
18	Prepayments		110,291	49,168	60,029	3,525	56,504	1,094
19	Non-Plant & Work Cash		(30,521)	(18,300)	(11,861)	(761)	(11,100)	(360)
20	Total Additions		921,081	370,300	546,743	27,452	519,291	4,038
21	**Rate Base**		11,918,156	5,342,409	6,461,008	381,671	6,079,337	114,739

Income Statement

			MN	Res	C&I Tot	Sm Non-D	Demand	St Ltg
22A	**Tot Oper Rev - Pres**		3,811,699	1,465,722	2,317,881	126,014	2,191,867	28,097
22B	**Tot Oper Rev - Prop**		4,489,046	1,769,817	2,685,199	145,785	2,539,414	34,030
23	Oper & Maint		2,542,082	952,010	1,575,331	79,269	1,496,061	14,741
24	Book Depr + IRS Int		899,980	381,334	509,760	28,197	481,564	8,885
25	Payroll, Rl Est & Prop Tax		260,813	118,921	139,335	8,482	130,853	2,557
26	Deferred Inc Tax & Net ITC		(150,377)	(61,667)	(86,885)	(4,805)	(82,080)	(1,825)
27A	Present Income Tax		(89,624)	(52,941)	(36,527)	(857)	(35,670)	(156)
27B	Proposed Income Tax		105,059	34,462	69,048	4,826	64,222	1,549
28	Allow Funds Dur Const		38,536	16,472	21,967	1,122	20,844	97
29A	**Present Return**		387,362	144,536	238,834	16,850	221,983	3,992
29B	**Proposed Return**		870,025	361,228	500,577	30,939	469,638	8,220
30A	**Pres Ret on Rt Base**		3.25%	2.71%	3.70%	4.41%	3.65%	3.48%
30B	**Prop Ret on Rt Base**		**7.30%**	6.76%	7.75%	8.11%	7.73%	7.16%
31A	**Pres Ret on Common**		2.50%	1.46%	3.35%	4.71%	3.26%	2.93%
31B	**Prop Ret on Common**		**10.21%**	9.18%	11.06%	11.75%	11.02%	9.95%

Northern States Power Company
Electric Utility - Minnesota
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PRES vs Equal Rev Reqts

			1=2+3+6	2	3=4+5	4	5	6
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	**UnAdj Equal Rev Reqt @ 7.30%**		**3,866,065**	**1,584,959**	**2,248,295**	**123,497**	**2,124,798**	**32,810**
2	**Present Revenue**		**3,190,814**	**1,242,316**	**1,921,839**	**108,110**	**1,813,729**	**26,659**
3	**UnAdj Revenue Deficiency**		**675,250**	**342,643**	**326,456**	**15,387**	**311,069**	**6,151**
4	**UnAdj Deficiency / Present**		**21.16%**	**27.58%**	**16.99%**	**14.23%**	**17.15%**	**23.07%**
			[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS					
5	**Pres Int Rate Discounts**							
6	**Pres Econ Dvlp Rate Discounts**							
7	**Pres Int Rate Disc Cost Alloc**	**D10S**						
8	**Pres Econ Dvlp Disc Cost Alloc**	**R01**						
						HIGHLY CONFIDENTIAL TRADE SECRET ENDS]		
9	**Revenue Requirement Shift**		**0**	**(1,002)**	**931**	**1,145**	**(214)**	**71**
10	**Adj Equal Rev Reqt (Rows 1+9)**		**3,866,065**	**1,583,957**	**2,249,226**	**124,642**	**2,124,584**	**32,882**
11	**Adj Rev Defic vs Pres Rev (Row 2)**		**675,250**	**341,641**	**327,387**	**16,532**	**310,855**	**6,222**
12	**Adj Deficiency / Adj Present**		**21.16%**	**27.50%**	**17.04%**	**15.29%**	**17.14%**	**23.34%**
	Equal Customer Classification							
13	Min Sys & Service Drop		342,216	283,904	34,463	19,219	15,244	23,849
14	Energy Services		68,612	57,846	10,501	5,504	4,997	265
15	Total Customer **(Cusco)**		410,828	341,750	44,965	24,723	20,242	24,113
16	Ave Monthly Customers		1,389,660	1,220,945	140,527	89,854	50,674	28,188
17	Svc Drop Reqt	$ / Mo / Cust	$20.52	$19.38	$20.44	$17.82	$25.07	$70.51
18	Ener Svcs Reqt	$ / Mo / Cust	$4.11	$3.95	$6.23	$5.10	$8.22	$0.78
19	Total Reqt	$ / Mo / Cust	$24.64	$23.33	$26.66	$22.93	$33.29	$71.29
	Equal Energy Classification							
20	On Peak Rev Reqt		849,448	260,438	587,496	26,506	560,990	1,514
21	Off Peak Rev Reqt		846,026	277,140	564,321	23,418	540,903	4,565
22	Total Ener Rev Reqt		1,695,474	537,577	1,151,817	49,924	1,101,893	6,080
23	Annual MWh Sales		28,062,414.443	8,661,624	19,277,580	803,030	18,474,550	123,211
24	On Pk Reqt	Mills / kWh	30.270	30.068	30.476	33.008	30.366	12.292
25	Off Pk Reqt	Mills / kWh	30.148	31.996	29.273	29.162	29.278	37.054
26	Total Reqt	Mills / kWh	60.418	62.064	59.749	62.169	59.644	49.346
	Equal Demand Classification							
27	Energy-Related Prod		398,668	129,416	268,012	11,638	256,374	1,240
28	Capacity-Related Summer Peak Prod		403,210	159,189	244,021	11,165	232,856	0
29	Capacity-Related Winter Peak Prod		101,266	39,980	61,286	2,804	58,481	0
30	Total Capacity-Related Prod		504,476	199,169	305,306	13,969	291,337	0
31	Total Production		903,143	328,585	573,319	25,607	547,711	1,240
32	Transmission **(Transco)**		506,065	199,550	306,515	13,992	292,524	0
33	Primary Dist Subs		93,725	38,692	54,489	2,664	51,825	544
34	Prim Dist Lines		182,195	92,869	88,598	4,642	83,956	729
35	Second Dist, Trans		74,634	45,936	28,593	1,945	26,647	105
36	Total Distribution **(Disco)**		350,554	177,497	171,680	9,251	162,429	1,378
37	Total Demand Rev Reqt		1,759,762	705,632	1,051,514	48,850	1,002,663	2,617
38	Annual Billing kW		47,640,460	0	47,640,460	0	47,640,460	0
39	Base Rev Reqt	$ / kW	$0.00	$0.00	$5.63	$0.00	$5.38	$0.00
40	Summer Rev Reqt	$ / kW	$0.00	$0.00	$5.12	$0.00	$4.89	$0.00
41	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.29	$0.00	$1.23	$0.00
42	Prod Rev Reqt	$ / kW	$0.00	$0.00	$12.03	$0.00	$11.50	$0.00
43	Tran Rev Reqt	$ / kW	$0.00	$0.00	$6.43	$0.00	$6.14	$0.00
44	Dist Rev Reqt	$ / kW	$0.00	$0.00	$3.60	$0.00	$3.41	$0.00
45	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$22.07	$0.00	$21.05	$0.00
46	Tot Dmd Rev Reqt	Mills / kWh	62.709	81.466	54.546	60.832	54.273	21.241
47	Summer Billing kW		17,268,243	0	17,268,243	0	17,268,243	0
48	Winter Billing kW		30,372,217	0	30,372,217	0	30,372,217	0
49	Tot Summer Reqt	$ / kW	$0.00	$0.00	$29.79	$0.00	$28.42	$0.00
50	Tot Winter Reqt	$ / kW	$0.00	$0.00	$17.68	$0.00	$16.86	$0.00
51	Energy + Production **(Genco)**		2,598,618	866,163	1,725,136	75,531	1,649,604	7,319

Northern States Power Company
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PROP vs Equal Rev Reqts

			1=2+3+6	2	3=4+5	4	5	6
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	**Proposed Ret On Rt Base**		**7.30%**	**6.76%**	**7.75%**	**8.11%**	**7.73%**	**7.16%**
2	**UnAdj Equalized Rev Reqt**		**3,866,065**	**1,584,959**	**2,248,295**	**123,497**	**2,124,798**	**32,810**
3	**Proposed Revenue**		**3,866,065**	**1,544,588**	**2,288,885**	**127,815**	**2,161,070**	**32,591**
4	**UnAdj Revenue Deficiency**		**0**	**40,371**	**(40,590)**	**(4,318)**	**(36,272)**	**219**
5	**UnAdj Deficiency / Proposed**		**0.00%**	**2.61%**	**-1.77%**	**-3.38%**	**-1.68%**	**0.67%**
			[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS					
6	**Prop Interrupt Rate Discounts**							
7	**Prop Econ Dev Rate Discounts**							
8	**Prop Int Rate Disc Cost Alloc**	**D10S**						
9	**Prop ED Discount Cost Alloc**	**R01**						
								HIGHLY CONFIDENTIAL TRADE SECRET ENDS]
10	**Revenue Requirement Shift**		**0**	**7,724**	**(7,833)**	**1,040**	**(8,873)**	**108**
11	**Adj Equal Rev (Rows 2+10)**		**3,866,065**	**1,592,683**	**2,240,462**	**124,537**	**2,115,925**	**32,919**
12	**Adj Rev Defic vs Prop Rev (Row 3)**		**0**	**48,095**	**(48,423)**	**(3,278)**	**(45,145)**	**328**
13	**Adj Deficiency / Adj Prop**		**0.00%**	**3.11%**	**-2.12%**	**-2.56%**	**-2.09%**	**1.01%**
	Prop Customer Component							
14	Min Sys & Service Drop		329,818	270,123	36,035	20,043	15,992	23,660
15	Energy Services		68,578	57,807	10,506	5,506	5,000	265
16	Total Customer **(Cusco)**		398,396	327,931	46,541	25,549	20,992	23,924
17	Ave Monthly Customers		1,389,660	1,220,945	140,527	89,854	50,674	28,188
18	Svc Drop Reqt	$ / Mo / Cust	$19.78	$18.44	$21.37	$18.59	$26.30	$69.95
19	Ener Svcs Reqt	$ / Mo / Cust	$4.11	$3.95	$6.23	$5.11	$8.22	$0.78
20	Total Reqt	$ / Mo / Cust	$23.89	$22.38	$27.60	$23.70	$34.52	$70.73
	Prop Energy Component							
21	On Peak Rev Reqt		849,286	260,248	587,524	26,518	561,006	1,514
22	Off Peak Rev Reqt		845,826	276,936	564,325	23,428	540,898	4,565
23	Total Ener Rev Reqt		1,695,113	537,184	1,151,850	49,946	1,101,904	6,079
24	Annual MWh Sales		28,062,414	8,661,624	19,277,580	803,030	18,474,550	123,211
25	On Pk Reqt	Mills / kWh	30.264	30.046	30.477	33.023	30.366	12.290
26	Off Pk Reqt	Mills / kWh	30.141	31.973	29.274	29.174	29.278	37.047
27	Total Reqt	Mills / kWh	60.405	62.019	59.751	62.197	59.644	49.337
	Prop Demand Component							
28	Energy-Related Prod		388,332	116,847	270,277	12,424	257,853	1,208
29	Capacity-Related Summer Peak Prod		420,077	160,582	259,495	12,155	247,340	0
30	Capacity-Related Winter Peak Prod		105,502	40,330	65,172	3,053	62,119	0
31	Total Capacity-Related Prod		525,580	200,912	324,667	15,207	309,460	0
32	Total Production		913,912	317,760	594,944	27,631	567,313	1,208
33	Transmission **(Transco)**		508,765	192,138	316,627	14,956	301,672	0
34	Primary Dist Subs		95,007	37,036	57,421	2,865	54,556	550
35	Prim Dist Lines		180,574	88,704	91,145	4,833	86,312	725
36	Second Dist, Trans		74,298	43,836	30,357	2,036	28,321	104
37	Total Distribution **(Disco)**		349,878	169,576	178,923	9,733	169,190	1,379
38	Total Demand Rev Reqt		1,772,556	679,473	1,090,495	52,320	1,038,174	2,588
39	Annual Billing kW		47,640,460	0	47,640,460	0	47,640,460	0
40	Base Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$5.41	$0.00
41	Summer Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$5.19	$0.00
42	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$1.30	$0.00
43	Prod Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$11.91	$0.00
44	Tran Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$6.33	$0.00
45	Dist Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$3.55	$0.00
46	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$21.79	$0.00
47	Tot Dmd Rev Reqt	Mills / kWh	63.165	78.446	56.568	65.154	56.195	21.002
48	Summer Billing kW		17,268,243	0	17,268,243	0	17,268,243	0
49	Winter Billing kW		30,372,217	0	30,372,217	0	30,372,217	0
50	Tot Summer Reqt	$ / kW	$0.00	$0.00	$31.10	$0.00	$29.62	$0.00
51	Tot Winter Reqt	$ / kW	$0.00	$0.00	$18.22	$0.00	$17.34	$0.00
52	Energy + Production **(Genco)**		2,609,024	854,944	1,746,794	77,577	1,669,216	7,287
53	Prop Rev - Pres Rev (Pg 2)		675,250	302,272	367,046	19,705	347,341	5,932
54	Difference / Present		21.16%	24.33%	19.10%	18.23%	19.15%	22.25%

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - Minnesota
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Original Plant in Service

				1=2+3+6	2	3=4+5	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Summer Peak	D10S		2,767,350	1,094,565	1,672,785	76,619	1,596,166	0
2	WInter Peak	D10S		695,017	274,899	420,118	19,243	400,876	0
3	Total Peak	D10S		3,462,367	1,369,464	2,092,903	95,861	1,997,042	0
4	Base Load	E8760		6,454,502	2,045,513	4,386,637	189,550	4,197,087	22,353
5	Nuclear Fuel	E8760		2,832,839	897,762	1,925,266	83,192	1,842,074	9,810
6	Total	34.91%	120, 310-346	12,749,709	4,312,739	8,404,807	368,603	8,036,203	32,163
	Transmission								
7	Gen Step Up Base	E8760		135,054	42,800	91,786	3,966	87,820	468
8	Gen Step Up Peak	D10S		36,078	14,270	21,808	999	20,809	0
9	Total Gen Step Up			171,132	57,070	113,594	4,965	108,629	468
10	Bulk Transmission	D10S		3,887,698	1,537,694	2,350,004	107,637	2,242,366	0
11	Distrib Function	D60Sub		0	0	0	0	0	0
12	Direct Assign	Dir Assign		8,770	0	8,770	0	8,770	0
13	Total		350-359	4,067,600	1,594,765	2,472,368	112,602	2,359,765	468
	Distribution:								
	Substations								
14	Generat Step Up	STRATH		3,050	1,009	2,032	89	1,943	9
15	Bulk Transmission	D10S		1,904	753	1,151	53	1,098	0
16	Distrib Function	D60Sub		829,111	351,192	472,998	24,141	448,856	4,922
17	Direct Assign	Dir Assign		20,220.663	0	20,221	0	20,221	0
18	Total		360-363	854,286	352,954	496,401	24,283	472,118	4,931
	Overhead Lines								
19	Primary Capacity 1 Phase	D61PS1Ph		183,909	138,993	43,988	5,059	38,929	928
20	Primary Capacity Multi Phase	D61PS		378,777	143,082	234,398	9,228	225,171	1,296
21	Primary Customer 1 Phase	C61PS1Ph		100,223	95,250	4,633	3,960	673	340
22	Primary Customer Multi Phase	C61PS		206,417	184,282	21,244	13,575	7,669	891
23	Total Primary			869,326	561,607	304,264	31,822	272,442	3,456
24	Second Capacity	D62SecL		73,039	36,921	35,930	2,239	33,691	188
25	Second Customer	C62Sec		268,578	239,863	27,555	17,669	9,886	1,160
26	Total Secondary			341,617	276,784	63,485	19,908	43,577	1,348
27	Street Lighting	DASL		53,182	0	0	0	0	53,182
28	Total		364,365	1,264,126	838,390	367,749	51,730	316,019	57,986
	Underground Lines								
29	Primary Capacity 1 Phase	D61PS1Ph		253,582	191,649	60,653	6,976	53,676	1,280
30	Primary Capacity Multi Phase	D61PS		380,752	143,828	235,620	9,276	226,345	1,303
31	Primary Customer 1 Phase	C61PS1Ph		286,409	272,197	13,241	11,317	1,924	971
32	Primary Customer Multi Phase	C61PS		430,041	383,925	44,259	28,281	15,978	1,857
33	Total Primary			1,350,784	991,600	353,773	55,850	297,923	5,410
34	Second Capacity	D62SecL		149,998	75,824	73,788	4,598	69,190	387
35	Second Customer	C62Sec		221,110	197,470	22,685	14,546	8,139	955
36	Total Secondary			371,108	273,293	96,473	19,144	77,329	1,342
37	Street Lighting	DASL		0	0	0	0	0	0
38	Total		366,367	1,721,892	1,264,894	450,246	74,994	375,252	6,752
	Line Transformers								
39	Primary	D61PS		42,628	16,103	26,379	1,038	25,341	146
40	Second Capacity	D62SecL		131,687	66,567	64,780	4,036	60,744	340
41	Second Customer	C62Sec		235,736	210,532	24,186	15,509	8,677	1,018
42	Total		368	410,050	293,202	115,345	20,583	94,762	1,504
	Services								
43	Second Capacity	D62NLL		253,925	190,113	63,812	5,212	58,600	0
44	Second Customer	C62NL		230,470	218,565	11,905	7,633	4,271	0
43	Total Services	C62NL	369	484,395	408,678	75,717	12,845	62,871	0
44	Meters	C12WM	370	321,428	253,965	66,785	24,059	42,726	679
45	Street Lighting	Dir Assign	373	68,451	0	0	0	0	68,451
46	**Total Distribution**			5,124,628	3,412,083	1,572,243	208,494	1,363,749	140,302
47	**General & Common Plant**	PTD	303, 389-399	2,578,288	1,095,098	1,462,869	81,043	1,381,826	20,321
48	Prelim Elec Plant			24,520,225	10,414,685	13,912,287	770,743	13,141,543	193,254
49	TBT Investment	NEPIS		0	0	0	0	0	0
50	**Elec Plant in Serv**			24,520,225	10,414,685	13,912,287	770,743	13,141,543	193,254

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Accum Deprec; Net Plant

				1=2+3+6	2	3=4+5	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		1,642,519	649,663	992,856	45,476	947,380	0
2	Decom Int Peaking	D10S		0	0	0	0	0	0
3	Decom Int Baseload	E8760		0	0	0	0	0	0
4	Nuclear Fuel	E8760		2,667,411	845,336	1,812,837	78,334	1,734,503	9,238
5	Base Load	E8760		3,225,541	1,022,214	2,192,156	94,725	2,097,432	11,170
6	Total		108,111,115,120.5	7,535,471	2,517,213	4,997,850	218,535	4,779,315	20,408
	Transmission								
7	Gen Step Up Base	E8760		16,790	5,321	11,411	493	10,918	58
8	Gen Step Up Peak	D10S		18,069	7,147	10,922	500	10,422	0
9	Total Gen Step Up			34,859	12,468	22,333	993	21,340	58
10	Bulk Transmission	D10S		910,945	360,304	550,640	25,221	525,419	0
11	Distrib Function	D60Sub		0	0	0	0	0	0
12	Direct Assign	Dir Assign		2,643	0	2,643	0	2,643	0
13	Total		108,111,115,120.5	948,447	372,772	575,616	26,214	549,402	58
	Distribution								
14	Generat Step Up	STRATH		1,823	603	1,214	53	1,161	5
15	Bulk Transmission	D10S		639	253	386	18	369	0
16	Distrib Function	D60Sub		256,002	108,436	146,046	7,454	138,592	1,520
17	Direct Assign	Dir Assign		6,606	0	6,606	0	6,606	0
18	Total Substations			265,069	109,292	154,252	7,525	146,728	1,525
19	Overhead Lines	POL		431,823	286,393	125,623	17,671	107,952	19,808
20	Underground	PUL		566,395	416,071	148,103	24,668	123,435	2,221
21	Line Transformers	P68		182,565	130,541	51,355	9,164	42,190	669
22	Services	P69		219,931	185,553	34,378	5,832	28,546	0
23	Meters	C12WM		66,530	52,566	13,823	4,980	8,843	140
24	Street Lighting	P73		9,376	0	0	0	0	9,376
25	Total		108,111,115,120.5	1,741,690	1,180,416	527,534	69,840	457,693	33,740
26	**General & CommonPlant**	PTD	108,111,115,120.5	1,343,339	570,568	762,184	42,225	719,959	10,587
27	**Total Accum Depr**			11,568,947	4,640,969	6,863,184	356,814	6,506,369	64,794
28	**Net Elec Plant**			12,951,278	5,773,715	7,049,103	413,929	6,635,174	128,460
29	**Net Plant w/ TBT**			12,951,278	5,773,715	7,049,103	413,929	6,635,174	128,460
	Subtractions: Accum Defer Inc Tax								
	Production								
30	Peaking Plant	D10S		349,748	138,335	211,413	9,683	201,730	0
31	Base Load	E8760		939,080	297,606	638,222	27,578	610,644	3,252
32	Nuclear Fuel	E8760		(8,768)	(2,779)	(5,959)	(257)	(5,701)	(30)
33	Total		190,281,282,283	1,280,060	433,163	843,676	37,004	806,672	3,222
	Transmission								
34	Gen Step Up Base	E8760		19,365	6,137	13,161	569	12,592	67
35	Gen Step Up Peak	D10S		3,840	1,519	2,321	106	2,215	0
36	Total Gen Step Up			23,205	7,656	15,482	675	14,807	67
37	Bulk Transmission	D10S		743,664	294,140	449,524	20,590	428,934	0
38	Distrib Function	D60Sub		0	0	0	0	0	0
39	Direct Assign	Dir Assign		1,533	0	1,533	0	1,533	0
40	Total		281,282,283	768,402	301,796	466,539	21,265	445,274	67
	Distribution								
41	Generat Step Up	STRATH		193	64	128	6	123	1
42	Bulk Transmission	D10S		234	93	142	6	135	0
43	Distrib Function	D60Sub		112,997	47,863	64,463	3,290	61,173	671
44	Direct Assign	Dir Assign		2,444	0	2,444	0	2,444	0
45	Total Substations			115,868	48,019	67,177	3,302	63,875	671
46	Overhead Lines	POL		147,268	97,671	42,842	6,026	36,816	6,755
47	Underground	PUL		223,481	164,168	58,437	9,733	48,703	876
48	Line Transformers	P68		54,525	38,987	15,338	2,737	12,601	200
49	Services	P69		19,720	16,638	3,082	523	2,560	0
50	Meters	C12WM		9,597	7,583	1,994	718	1,276	20
51	Street Lighting	P73		13,009	0	0	0	0	13,009
52	Total		281,282,283	583,468	373,066	188,870	23,040	165,830	21,532
53	**General & Common Plant**	PTD	281,282,283	149,492	63,495	84,819	4,699	80,120	1,178
54	**Total Deferred Tax**			2,781,423	1,171,520	1,583,904	86,008	1,497,896	25,999
55	Net Operating Loss (NOL) Carry F	NEPIS		(900,149)	(401,289)	(489,932)	(28,769)	(461,163)	(8,928)
56	Non-Plant Related	LABOR		72,930	31,375	40,866	2,471	38,395	689
57	**Accum Def W/ Adj**			1,954,203	801,606	1,134,838	59,710	1,075,128	17,760

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HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - Minnesota
2024 Class Cost of Service Study ($000)

Additions: CWIP, Etc; Rate Base

		Alloc	FERC Accounts	1=2+3+6 MN	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5 Demand	6 St Ltg
	Production								
1	Peaking Plant	D10S		252,402	99,832	152,570	6,988	145,582	0
2	Base Load	E8760		(23,982)	(7,600)	(16,299)	(704)	(15,594)	(83)
3	Nuclear Fuel	E8760		67,724	21,463	46,027	1,989	44,038	235
4	Total		107	296,145	113,695	182,298	8,273	174,026	151
	Transmission								
5	Gen Step Up Base	E8760		0	0	0	0	0	0
6	Gen Step Up Peak	D10S		0	0	0	0	0	0
7	Total Gen Step Up			0	0	0	0	0	0
8	Bulk Transmission	D10S		142,054	56,186	85,867	3,933	81,934	0
9	Distrib Function	D60Sub		0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0
11	Total		107	142,054	56,186	85,867	3,933	81,934	0
	Distribution								
12	Generat Step Up	STRATH		0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0
14	Distrib Function	D60Sub		20,045	8,491	11,436	584	10,852	119
15	Direct Assign	Dir Assign		78	0	78	0	78	0
16	Total Substations			20,123	8,491	11,514	584	10,930	119
17	Overhead Lines	POL		23,309	15,459	6,781	954	5,827	1,069
18	Underground	PUL		39,343	28,901	10,287	1,714	8,574	154
19	Line Transformers	P68		(18,982)	(13,573)	(5,339)	(953)	(4,387)	(70)
20	Services	P69		8,721	7,358	1,363	231	1,132	0
21	Meters	C12WM		0	0	0	0	0	0
22	Street Lighting	P73		198	0	0	0	0	198
23	Total		107	72,712	46,636	24,606	2,529	22,076	1,471
24	**General & Common Plant**	PTD	107	105,932	44,993	60,104	3,330	56,774	835
25	**Total CWIP**			616,842	261,510	352,875	18,065	334,810	2,457
26	Fuel Inventory	E8760	151,152	69,767	22,110	47,416	2,049	45,367	242
	Materials & Supplies								
27	Production	P10		137,834	46,624	90,862	3,985	86,878	348
28	Trans & Distr	TD		16,867	9,187	7,421	589	6,832	258
29	Total		154	154,701	55,811	98,284	4,574	93,710	606
	Prepayments								
30	Miscellaneous	NEPIS		110,291	49,168	60,029	3,525	56,504	1,094
31	Fuel	E8760		0	0	0	0	0	0
32	Insurance	NEPIS	135,143,184,186,232	0	0	0	0	0	0
33	Total		235,252,165	110,291	49,168	60,029	3,525	56,504	1,094
34	Non-Plant Assets & Liab	LABOR	190,283,	148,557	63,911	83,243	5,034	78,209	1,403
35	Working Cash	PT0	calculated	(179,078)	(82,211)	(95,104)	(5,795)	(89,309)	(1,763)
36	**Total Additions**			921,081	370,300	546,743	27,452	519,291	4,038
37	**Total Rate Base**			11,918,156	5,342,409	6,461,008	381,671	6,079,337	114,739
38	**Common Rate Base (@ 52.50%)**			6,257,031.9	2,804,765	3,392,029	200,377	3,191,652	60,238

Northern States Power Company
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Operating Rev (Cal Month)

				1=2+3+6	2	3=4+5	4	5	6
	Retail Revenue	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Present Rate Revenue	R01; (calc)	440, 442,444,445	3,190,814	1,242,316	1,921,839	108,110	1,813,729	26,659
2	Proposed Rate Revenue	PROREV; (calc)		3,866,065	1,544,588	2,288,885	127,815	2,161,070	32,591
3	Equal Rate Revenue			3,866,065	1,584,959	2,248,295	123,497	2,124,798	32,810
	Other Retail Revenue								
4	Interdepartmental	R01; R02	448	625	243	377	21	355	5
5	Gross Earnings Tax	R01; R02	408	0	0	0	0	0	0
6	CIP Adjustment to Program Costs	E99XCIP	456	0	0	0	0	0	0
7	**Tot Other Retail Rev**			625	243	377	21	355	5
	Other Operating Revenue								
8	Interchg Prod Capacity	P10	456	465,447	157,443	306,830	13,456	293,374	1,174
9	Interchg Prod Energy	E8760	456	0	0	0	0	0	0
10	Interchg Tr Bulk Supply	D10S	456	0	0	0	0	0	0
11	Dist Int Sales; Oth Serv	E8760	412,451,456	0	0	0	0	0	0
12	Dist Overhd Line Rent	POL	454	4,793	3,179	1,394	196	1,198	220
13	Connection Charges	C11	451	1,730	1,520	175	112	63	35
14	Sales For Resale	E8760	447	(0)	(0)	(0)	(0)	(0)	(0)
15	Joint Op Agree-Other PSCo Rev	D10S	456	0	0	0	0	0	0
16	Misc Ancillary Trans Rev	D10S		222,628	88,056	134,572	6,164	128,409	0
17	MISO	D10S	456	(91,627)	(36,241)	(55,386)	(2,537)	(52,849)	0
18	Other	D10S	451,456,457	12,073	4,775	7,298	334	6,963	0
19	Late Pay Chg - Pres	R16C; R02		5,215	4,431	782	157	625	3
20	**Tot Other Op - Pres**		450	620,259	223,162	395,665	17,883	377,782	1,432
21	Incr Misc Serv - Prop	C62NL		892	846	46	30	17	0
22	Incr Inter-Dept'l - Prop	R01; R02		101	39	61	3	58	1
23	Incr Late Pay - Prop	(R16C); R02		1,104	938	165	33	132	1
	Tot Incr Other Op			2,097	1,823	272	66	206	2
24	**Tot Other Op - Prop**			622,356	224,985	395,937	17,949	377,988	1,434
25	**Tot Oper Rev - Pres**			3,811,699	1,465,722	2,317,881	126,014	2,191,867	28,097
26	**Tot Oper Rev - Prop**			4,489,046	1,769,817	2,685,199	145,785	2,539,414	34,030
	Tot Oper Rev - Eql			4,489,046	1,810,188	2,644,609	141,467	2,503,142	34,249
	Operating & Maint (Pg 1 of 2)								
	Production Expen								
27	**Fuel**	E8760	501,518,547	615,932	195,197	418,602	18,088	400,514	2,133
	Purchased Power								
28	Purchases: Cap Peak	D10S		108,085	42,751	65,334	2,993	62,342	0
29	Purchases: Cap Base	D10S		40,221	15,908	24,312	1,114	23,199	0
30	Purchases: Demand		555	148,306	58,659	89,647	4,106	85,541	0
31	Purchases: Other Energy	E8760	555	380,763	120,668	258,776	11,182	247,594	1,319
32	Tot Non-Assoc Purch			529,068	179,328	348,422	15,288	333,134	1,319
33	Interchg Agr Capacity	P10WoN	557	50,286	17,316	32,856	1,447	31,409	113
34	Interchg Agr Energy	E8760	557	13,377	4,239	9,092	393	8,699	46
35	Tot Wis Interchg Purch			63,663	21,556	41,947	1,840	40,107	160
36	**Tot Purchased Power**			592,731	200,883	390,370	17,128	373,242	1,478
	Other Production		500,502,505-507 509-514,517-519,520, 523-525,528-532,535, 539,543-546,548-550 552-554,556,557 575.1-575.8						
37	Capacity Related	D10S		97,403	38,525	58,877	2,697	56,180	0
38	Energy Related	E8760		335,162	106,217	227,784	9,843	217,941	1,161
39	Total Other Produc	22.52%		432,564.270	144,742	286,661	12,539	274,122	1,161
40	**Total Production**			1,641,228	540,822	1,095,633	47,756	1,047,878	4,772
41	**Transmission Exp**	D10S	560-563, 565-568 570-573	272,297	107,701	164,596	7,539	157,057	0

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Northern States Power Company
Electric Utility - Minnesota
2024 Class Cost of Service Study ($000)

Operating & Maint (Pg 2 of 2)

				1=2+3+6	2	3=4+5	4	5	6
	Distribution Expen	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Supervision & Eng'rg	ZDTS	580,590	11,131	7,343	3,324	479	2,845	464
2	Load Dispatching	T20D80	581	1,124	470	649	32	616	5
3	Substations	P61	582,591,592	6,000	2,479	3,487	171	3,316	35
4	Overhead Lines	POL	583,593	56,499	37,471	16,436	2,312	14,124	2,592
5	Underground Lines	PUL	584, 594	21,742	15,971	5,685	947	4,738	85
6	Line Transformers	P68	595	32	23	9	2	7	0
7	Meters	C12WM	586,597,598	1,965	1,552	408	147	261	4
8	Customer Install'n	OXDTS	587	2,726	1,773	814	110	704	138
9	Street Lighting	Dir Assign	585,596	1,797	0	0	0	0	1,797
10	Miscellaneous	OXDTS	588	21,525	14,006	6,432	872	5,560	1,087
11	Rents (Pole Attachmts)	POL	589	3,850	2,553	1,120	158	962	177
12	**Total Distribution**			128,391	83,643	38,365	5,229	33,135	6,383
13	**Customer Accounting**	C11WA	901-905	51,861	43,683	8,008	4,179	3,829	170
14	**Sales, Econ Dvlp & Other**	R01	912	8,862	3,450	5,337	300	5,037	74
	Admin & General								
15	Salaries	LABOR	920	90,148	38,783	50,514	3,055	47,459	851
16	Office Supplies	OXTS	921	63,795	23,889	39,537	1,989	37,548	370
17	Admin Transfer Credit	OXTS	922	(70,614)	(26,442)	(43,763)	(2,201)	(41,562)	(409)
18	Outside Services	LABOR	923	19,787	8,513	11,088	670	10,417	187
19	Property Insurance	NEPIS	924	10,220	4,556	5,563	327	5,236	101
20	Pensions & Benefits	LABOR	926	60,213	25,904	33,740	2,040	31,700	569
21	Injuries & Claims	LABOR	925	16,572	7,130	9,286	562	8,725	157
22	Regulatory Exp	R01; R02	928	6,670	2,597	4,017	226	3,791	56
23	General Advertising	OXTS	930.1	194	73	120	6	114	1
24	Contributions	OXTS		0	0	0	0	0	0
25	Misc General Exp	OXTS	929, 930.2	985	369	610	31	579	6
26	Rents	OXTS	931	51,964	19,458	32,204	1,620	30,584	301
27	Maint of General Plant	OXTS	935	1,158	434	718	36	682	7
28	Total			251,092	105,262	143,634	8,360	135,274	2,196
	Cust Service & Info								
29	Cust Assist Exp - Non-CIP	C11P10	908	1,151	700	438	54	384	13
30	CIP Total	E99XCIP	908	131,762.100	42,756	88,398	3,963	84,434	608
31	Instructional Advertising	C11P10	909	792	482	301	37	264	9
32	Total			133,705	43,938	89,136	4,054	85,082	630
33	Amortizations	LABOR		54,647	23,510	30,621	1,852	28,769	516
34	**Total O&M Expense**			2,542,082	952,010	1,575,331	79,269	1,496,061	14,741

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				1=2+3+6	2	3=4+5	4	5	6
	Book Depreciation								
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		146,286	57,860	88,426	4,050	84,375	0
2	Base Load	E8760		327,930	103,925	222,869	9,630	213,239	1,136
3	Total		403,413	474,216	161,785	311,295	13,680	297,614	1,136
	Transmission								
4	Gen Step Up Base	E8760		2,179	691	1,481	64	1,417	8
5	Gen Step Up Peak	D10S		1,280	506	774	35	738	0
6	Total Gen Step Up			3,459	1,197	2,255	99	2,155	8
7	Bulk Transmission	D10S		80,796	31,957	48,839	2,237	46,602	0
8	Distrib Function	D60Sub		0	0	0	0	0	0
9	Direct Assign	Dir Assign		183	0	183	0	183	0
10	Total		403,413	84,439	33,154	51,277	2,336	48,940	8
	Distribution								
11	Generat Step Up	STRATH		71	24	48	2	45	0
12	Bulk Transmission	D10S		44	17	26	1	25	0
13	Distrib Function	D60Sub		18,921	8,015	10,794	551	10,243	112
14	Direct Assign	Dir Assign		453	0	453	0	453	0
15	Total Substations		403,413	19,489	8,055	11,321	554	10,767	113
16	Overhead Lines	POL		42,722	28,334	12,428	1,748	10,680	1,960
17	Underground	PUL		39,353	28,909	10,290	1,714	8,576	154
18	Line Transformers	P68		11,334	8,104	3,188	569	2,619	42
19	Services	P69		28,519	24,062	4,458	756	3,702	0
20	Meters	C12WM		15,682	12,391	3,258	1,174	2,085	33
21	Street Lighting	P73		4,021	0	0	0	0	4,021
22	Total		403,413	161,120	109,854	44,944	6,515	38,429	6,322
23	**General & Common Plant**	PTD	403,413	180,205	76,540	102,245	5,664	96,580	1,420
24	**Total Book Deprec**		403,404	899,980	381,334	509,760	28,197	481,564	8,885
	Real Estate & Property Tax								
	Production								
25	Peaking Plant	D10S		36,049	14,258	21,790	998	20,792	0
26	Base Load	E8760		67,201	21,297	45,672	1,974	43,698	233
27	Total		408.1	103,250	35,555	67,462	2,972	64,491	233
	Transmission								
28	Gen Step Up Base	E8760		1,808.7993	573	1,229	53	1,176	6
29	Gen Step Up Peak	D10S		483.2034	191	292	13	279	0
30	Total Gen Step Up			2,292.0027	764	1,521	66	1,455	6
31	Bulk Transmission	D10S		52,068.6429	20,595	31,474	1,442	30,032	0
32	Distrib Function	D60Sub		0	0	0	0	0	0
33	Direct Assign	Dir Assign		117	0	117	0	117	0
34	Total		408.1	54,478.102	21,359	33,113	1,508	31,605	6
	Distribution								
35	Generat Step Up	STRATH		45	15	30	1	28	0
36	Bulk Transmission	D10S		28	11	17	1	16	0
37	Distrib Function	D60Sub		12,126	5,136	6,918	353	6,565	72
38	Direct Assign	Dir Assign		296	0	296	0	296	0
39	Total Substations			12,494	5,162	7,260	355	6,905	72
40	Overhead Lines	POL		18,488	12,262	5,378	757	4,622	848
41	Underground	PUL		25,183	18,500	6,585	1,097	5,488	99
42	Line Transformers	P68		5,997	4,288	1,687	301	1,386	22
43	Services	P69		7,084	5,977	1,107	188	920	0
44	Meters	C12WM		4,701	3,714	977	352	625	10
45	Street Lighting	P73		1,001	0	0	0	0	1,001
46	Total		408.1	74,950	49,903	22,995	3,049	19,945	2,052
47	**General & Common Plant**	PTD	408.1	0	0	0	0	0	0
48	**Tot Rl Est & Pr Tax**			232,678	106,817	123,570	7,529	116,041	2,291
49	Gross Earnings Tax	R01; R02		0	0	0	0	0	0
50	Payroll Taxes	LABOR		28,135	12,104	15,765	953	14,812	266
51	**Tot Non-Inc Taxes**			260,813	118,921	139,335	8,482	130,853	2,557

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2024 Class Cost of Service Study ($000)

Provision For Defer Inc Tax

				1=2+3+6	2	3=4+5	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		23,867	9,440	14,427	661	13,766	0
2	Nuclear Fuel	E8760		(368)	(117)	(250)	(11)	(239)	(1)
3	Base Load	E8760		(55,705)	(17,654)	(37,859)	(1,636)	(36,223)	(193)
4	Total		410, 411	(32,207)	(8,330)	(23,682)	(986)	(22,696)	(194)
	Transmission								
5	Gen Step Up Base	E8760		644	204	438	19	419	2
6	Gen Step Up Peak	D10S		153	61	93	4	88	0
7	Total Gen Step Up			797	265	530	23	507	2
8	Bulk Transmission	D10S		10,183	4,028	6,156	282	5,874	0
9	Distrib Function	D60Sub		0	0	0	0	0	0
10	Direct Assign	Dir Assign		19	0	19	0	19	0
11	Total		410, 411	11,000	4,293	6,705	305	6,400	2
	Distribution								
12	Generat Step Up	STRATH		(41)	(13)	(27)	(1)	(26)	(0)
13	Bulk Transmission	D10S		(6)	(2)	(4)	(0)	(3)	0
14	Distrib Function	D60Sub		763	323	435	22	413	5
15	Direct Assign	Dir Assign		(46)	0	(46)	0	(46)	0
16	Total Substations			671	307	359	21	338	4
17	Overhead Lines	POL		3,352	2,223	975	137	838	154
18	Underground	PUL		(1,920)	(1,411)	(502)	(84)	(418)	(8)
19	Line Transformers	P68		(1,826)	(1,306)	(514)	(92)	(422)	(7)
20	Services	P69		695	587	109	18	90	0
21	Meters	C12WM		(63)	(50)	(13)	(5)	(8)	(0)
22	Street Lighting	P73		(479)	0	0	0	0	(479)
23	Total		410, 411	430	351	414	(4)	418	(335)
24	**General & Common Plant**	PTD	410, 411	2,914	1,238	1,654	92	1,562	23
25	**Net Operating Loss (NOL) Carry**	NEPIS		(142,583)	(63,564)	(77,605)	(4,557)	(73,048)	(1,414)
26	**Non - Plant Related**	LABOR	410, 411	11,280	4,853	6,320	382	5,938	107
27	**Tot Prov For Defer**			(149,166)	(61,160)	(86,194)	(4,768)	(81,426)	(1,812)

Inv Tax Credit; Total Oper Exp

	Production								
28	Peaking Plant	D10S		(275)	(109)	(166)	(8)	(159)	0
29	Base Load	E8760		(523)	(166)	(356)	(15)	(340)	(2)
30	Total		411	(799)	(275)	(522)	(23)	(499)	(2)
	Transmission								
31	Gen Step Up Base	E8760		0	0	0	0	0	0
32	Gen Step Up Peak	D10S		0	0	0	0	0	0
33	Total Gen Step Up			0	0	0	0	0	0
34	Bulk Transmission	D10S		(150)	(59)	(91)	(4)	(87)	0
35	Distrib Function	D60Sub		0	0	0	0	0	0
36	Direct Assign	Dir Assign		0	0	0	0	0	0
37	Total		411	(150)	(59)	(91)	(4)	(87)	0
	Distribution								
38	Generat Step Up	STRATH		0	0	0	0	0	0
39	Bulk Transmission	D10S		0	0	0	0	0	0
40	Distrib Function	D60Sub		0	0	0	0	0	0
41	Direct Assign	Dir Assign		0	0	0	0	0	0
42	Total Substations			0	0	0	0	0	0
43	Overhead Lines	POL		(256)	(169)	(74)	(10)	(64)	(12)
44	Underground	PUL		0	0	0	0	0	0
45	Line Transformers	P68		0	0	0	0	0	0
46	Services	P69		0	0	0	0	0	0
47	Meters	C12WM		0	0	0	0	0	0
48	Street Lighting	P73		0	0	0	0	0	0
49	Total		411	(256)	(169)	(74)	(10)	(64)	(12)
50	**General & Common Plant**	PTD	411	(6)	(3)	(4)	(0)	(3)	(0)
51	**Net Inv Tax Credit**			(1,211)	(507)	(691)	(38)	(653)	(14)
28	TBT Misc Net Exp	NEPIS		0	0	0	0	0	0
52	**Total Operating Exp**			**3,552,498**	**1,390,599**	**2,137,541**	**111,143**	**2,026,398**	**24,358**
53A	**Pres Op Inc Before Inc Tax**			**259,202**	**75,123**	**180,340**	**14,871**	**165,469**	**3,739**
53B	**Prop Op Inc Before Inc Tax**			**936,548**	**379,218**	**547,658**	**34,643**	**513,016**	**9,672**

2024 Class Cost of Service Study ($000)

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HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Tax Deprec; Inc Tax & Return

		Alloc	FERC Accounts	1=2+3+6 MN	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5 Demand	6 St Ltg
	Production								
1	Peaking Plant	D10S		264,610	104,661	159,949	7,326	152,623	0
2	Nuclear Fuel	E8760		97,374	30,859	66,177	2,860	63,318	337
3	Base Load	E8760		214,579	68,003	145,833	6,302	139,532	743
4	Total		tax books	576,563	203,523	371,960	16,487	355,473	1,080
	Transmission								
5	Gen Step Up Base	E8760		5,250	1,664	3,568	154	3,414	18
6	Gen Step Up Peak	D10S		1,338	529	809	37	772	0
7	Total Gen Step Up			6,588	2,193	4,377	191	4,185	18
8	Bulk Transmission	D10S		130,793	51,732	79,060	3,621	75,439	0
9	Distrib Function	D60Sub		0	0	0	0	0	0
10	Direct Assign	Dir Assign		275	0	275	0	275	0
11	Total		tax books	137,656	53,925	83,713	3,812	79,900	18
	Distribution								
12	Generat Step Up	STRATH		0	0	0	0	0	0
13	Bulk Transmission	D10S		19	7	11	1	11	0
14	Distrib Function	D60Sub		24,386	10,329	13,912	710	13,202	145
15	Direct Assign	Dir Assign		251	0	251	0	251	0
16	Total Substations			24,656	10,337	14,175	711	13,464	145
17	Overhead Lines	POL		56,494	37,468	16,435	2,312	14,123	2,591
18	Underground	PUL		55,259	40,593	14,449	2,407	12,043	217
19	Line Transformers	P68		16,744	11,973	4,710	841	3,870	61
20	Services	P69		23,084	19,476	3,608	612	2,996	0
21	Meters	C12WM		4,827	3,814	1,003	361	642	10
22	Street Lighting	P73		2,869	0	0	0	0	2,869
23	Total		tax books	183,934	123,660	54,380	7,243	47,137	5,894
24	**General & Common Plant**	PTD	tax books	231,065	98,142	131,101	7,263	123,838	1,821
25	Net Operating Loss (NOL) Carry F	NEPIS		0	0	0	0	0	0
26	**Total Tax Deprec**			1,129,217	479,250	641,154	34,806	606,348	8,813
27	Interest Expense		427,431	231,212.23	103,643	125,344	7,404	117,939	2,226
28	Other Tax Timing Differ	LABOR		8,489	3,652	4,757	288	4,469	80
29	Meals & Enter	LABOR		1,160	499	650	39	611	11
30	Total Tax Deductions			1,370,079	587,044	771,905	42,537	729,367	11,130
	Inc Tax Additions								
31	Book Depreciation			899,979.583	381,334	509,760	28,197	481,564	8,885
32	Deferred Inc Tax & ITC			(150,376.823)	(61,667)	(86,885)	(4,805)	(82,080)	(1,825)
33	Nuclear Fuel Book Burn	E8760		100,112.035	31,727	68,039	2,940	65,099	347
34	Tax Capitalized Leases	PTD		40,732.311	17,301	23,111	1,280	21,830	321
35	Avoided Tax Interest	RTBASE		27,816.324	12,469	15,080	891	14,189	268
36	Total Tax Additions			918,263.430	381,163	529,104	28,503	500,602	7,996
37	**Total Inc Tax Adjustments**			(451,815)	(205,880)	(242,800)	(14,035)	(228,766)	(3,135)
38A	**Pres Taxable Net Income**			(192,614)	(130,757)	(62,460)	836	(63,297)	604
38B	**Prop Taxable Net Income**			484,733	173,338	304,858	20,608	284,250	6,537
39A	Pres Fed & State Inc Tax			(89,624)	(52,941)	(36,527)	(857)	(35,670)	(156)
39B	Prop Fed & State Inc Tax			105,059	34,462	69,048	4,826	64,222	1,549
40A	Pres Preliminary Return	(total); BASE		348,826	128,064	216,867	15,728	201,139	3,895
40B	Prop Preliminary Return	(total); BASE		831,489	344,756	478,611	29,817	448,794	8,123
41	Total AFUDC			38,536	16,472	21,967	1,122	20,844	97
42A	**Present Total Return**			387,362	144,536	238,834	16,850	221,983	3,992
42B	**Proposed Total Return**			870,025	361,228	500,577	30,939	469,638	8,220
43A	**Pres % Return on Rate Base**			3.25%	2.71%	3.70%	4.41%	3.65%	3.48%
43B	**Prop % Return on Rate Base**			7.30%	6.76%	7.75%	8.11%	7.73%	7.16%
44A	**Present Common Return**			156,149	40,894	113,490	9,446	104,044	1,766
44B	**Proposed Common Return**			638,813	257,585	375,234	23,535	351,699	5,994
45A	**Pres % Ret on Common Rt Base**			2.50%	1.46%	3.35%	4.71%	3.26%	2.93%
45B	**Prop % Ret on Common Rt Base**			10.21%	9.18%	11.06%	11.75%	11.02%	9.95%

Northern States Power Company
Electric Utility - Minnesota
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Allow For Funds Used During Constr

		Alloc	FERC Accounts	1=2+3+6 MN	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5 Demand	6 St Ltg
	Production								
1	Peaking Plant	D10S		19,904	7,873	12,032	551	11,480	0
2	Nuclear Fuel	E8760		3,776	1,197	2,566	111	2,455	13
3	Base Load	E8760		(5,602)	(1,775)	(3,807)	(165)	(3,643)	(19)
4	Total		419.1,432	18,078	7,294	10,791	497	10,293	(6)
	Transmission								
5	Gen Step Up Base	E8760		0	0	0	0	0	0
6	Gen Step Up Peak	D10S		0	0	0	0	0	0
7	Total Gen Step Up			0	0	0	0	0	0
8	Bulk Transmission	D10S		9,165	3,625	5,540	254	5,286	0
9	Distrib Function	D60Sub		0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0
11	Total		419.1,432	9,165	3,625	5,540	254	5,286	0
	Distribution								
12	Generat Step Up	STRATH		0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0
14	Distrib Function	D60Sub		1,746	740	996	51	945	10
15	Direct Assign	Dir Assign		5	0	5	0	5	0
16	Total Substations			1,751	740	1,001	51	950	10
17	Overhead Lines	POL		700	464	204	29	175	32
18	Underground	PUL		1,147	843	300	50	250	4
19	Line Transformers	P68		0	0	0	0	0	0
20	Services	P69		521	440	81	14	68	0
21	Meters	C12WM		55	44	11	4	7	0
22	Street Lighting	P73		0	0	0	0	0	0
23	Total		419.1,432	4,175	2,530	1,598	147	1,450	47
24	**General & Common Plant**	PTD	419.1,432	7,118	3,023	4,039	224	3,815	56
25	**Total AFUDC**			38,536	16,472	21,967	1,122	20,844	97

Labor Allocator

		Alloc	FERC Accounts	1=2+3+6 MN	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5 Demand	6 St Ltg
	Production								
26	Other Prod - Cap	D10S		73,127	28,924	44,203	2,025	42,178	0
27	Other Prod - Ene	E8760		136,322	43,202	92,648	4,003	88,644	472
28	Total		500 through 557	209,448	72,126	136,851	6,028	130,823	472
	Transmission								
29	Stepup Subtrans	P5161A		734	245	487	21	466	2
30	Bulk Power Subs	D10S		16,675	6,595	10,079	462	9,618	0
31	Total		560 through 571	17,409	6,840	10,567	483	10,084	2
	Distribution								
32	Superv & Eng	ZDTS	580, 590	8,685	5,730	2,594	374	2,220	362
33	Load Dispatch	D10S	581	102	41	62	3	59	0
34	Substation	P61	582, 592	3,486	1,440	2,025	99	1,926	20
35	Overhead Lines	POL	583, 593	13,869	9,198	4,035	568	3,467	636
36	Underground Lines	PUL	584, 594	10,411	7,648	2,722	453	2,269	41
37	Line Transformer	P68	595	29	21	8	1	7	0
38	Meter	C12WM	586, 597	3,963	3,131	823	297	527	8
39	Cust Installation	ZDTS	587	2,529	1,668	755	109	646	105
40	Street Lighting	P73	585, 596	550	0	0	0	0	550
41	Miscellaneous	OXDTS	588	10,680	6,950	3,192	433	2,759	539
42	Total			54,304	35,826	16,216	2,336	13,880	2,262
43	**Cust Accounting**	C11WA	901,902,903,904,905	13,832	11,650	2,136	1,115	1,021	45
44	**Sales Expense**	C11P10	912	1,741	1,059	662	81	580	20
45	**Admin & General**	LABOR	920,921,922,923,924,	153,210	65,913	85,850	5,191	80,659	1,447
46	**Service & Inform**	C11P10	908, 909	879	535	334	41	293	10
47	**Labor**			450,823	193,949	252,616	15,276	237,340	4,258

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			1=2+3+6	2	3=4+5	4	5	
INTERNAL ALLOCATORS		Intern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	50% Cus, 50% Prod Plt	C11P10	100.00%	60.84%	38.02%	4.68%	33.34%	1.14%
2	Peaking Plant Capacity	D10S	100.00%	39.55%	60.45%	2.77%	57.68%	0.00%
3	57% Dmd; 43% Energy: Sales & E	D57E43	100.00%	31.69%	67.96%	2.94%	65.03%	0.35%
4	40% Dmd; 60% Energy: CIP	D40E60	100.00%	31.69%	67.96%	2.94%	65.03%	0.35%
5	20%D10T; 80%D60Sub	T20D80	100.00%	41.80%	57.73%	2.88%	54.85%	0.47%
6	Labor w/o (or w/) A&G	LABOR	100.00%	43.02%	56.03%	3.39%	52.65%	0.94%
7	Net Plant In Service	NEPIS	100.00%	44.58%	54.43%	3.20%	51.23%	0.99%
8	Dis O&M w/o Sup & Misc	OXDTS	100.00%	65.07%	29.88%	4.05%	25.83%	5.05%
9	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	100.00%	37.45%	61.97%	3.12%	58.86%	0.58%
10	Production Plant	P10	100.00%	33.83%	65.92%	2.89%	63.03%	0.25%
11	Production Plant Wo Nuclear	P10WoN	100.00%	34.44%	65.34%	2.88%	62.46%	0.23%
12	Total P51 & P61A	P5161A	100.00%	33.34%	66.38%	2.90%	63.48%	0.27%
13	Distribution Plant	P60	100.00%	66.58%	30.68%	4.07%	26.61%	2.74%
14	Distr Substn Plant	P61	100.00%	41.32%	58.11%	2.84%	55.26%	0.58%
15	Line Transformer Plant	P68	100.00%	71.50%	28.13%	5.02%	23.11%	0.37%
16	Services Plant	P69	100.00%	84.37%	15.63%	2.65%	12.98%	0.00%
17	Dist Plt Overhead Lines	POL	100.00%	66.32%	29.09%	4.09%	25.00%	4.59%
18	Real Est & Property Tax	PT0	100.00%	45.91%	53.11%	3.24%	49.87%	0.98%
19	Produc, Trans & Distrib	PTD	100.00%	42.47%	56.74%	3.14%	53.59%	0.79%
20	Dist Plt Undground Lines	PUL	100.00%	73.46%	26.15%	4.36%	21.79%	0.39%
21	Rate Base (Non-Column)	RTBASE	100.00%	44.83%	54.21%	3.20%	51.01%	0.96%
22	Stratified Hydro Baseload	STRATH	100.00%	33.09%	66.62%	2.91%	63.72%	0.28%
23	Transmission & Distrib	TD	100.00%	54.47%	44.00%	3.49%	40.51%	1.53%
24	Labor Dis w/o Sup & Eng	ZDTS	100.00%	65.97%	29.86%	4.30%	25.56%	4.16%

			1=2+3+6	2	3=4+5	4	5	6
INTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
25	Labor w/o A&G	LABOR(S)	297,612	128,036	166,765	10,084	156,681	2,811
26	Dis O&M w/o Sup, Cust Install & M	OXDTS	93,009	60,520	27,794	3,768	24,026	4,695
27	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	2,487,931	931,633	1,541,887	77,563	1,464,324	14,410
28	Total P51 & P61A	P5161A	174,182	58,079	115,626	5,054	110,572	476
29	Produc, Trans & Distrib	PTD	21,941,937	9,319,586	12,449,417	689,700	11,759,717	172,933
30	Transmission & Distrib	TD	9,192,228	5,006,848	4,044,611	321,097	3,723,514	140,770
31	Labor Dis w/o Sup & Eng, Cust In	ZDTS	43,090	28,428	12,867	1,854	11,014	1,794

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			1=2+3+6	2	3=4+5	4	5	6
EXTERNAL ALLOCATORS		Extern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Customers - Ave Monthly	C11	100.00%	87.86%	10.11%	6.47%	3.65%	2.03%
2	Cust Acctg Wtg Factor	C11WA	100.00%	84.23%	15.44%	8.06%	7.38%	0.33%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	79.01%	20.78%	7.48%	13.29%	0.21%
4	Sec & Pri Customers	C61PS	100.00%	89.28%	10.29%	6.58%	3.72%	0.43%
5	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	100.00%	95.04%	4.62%	3.95%	0.67%	0.34%
6	C62Sec, w/o Ltg & C/I Undergrou	C62NL	100.00%	94.83%	5.17%	3.31%	1.85%	0.00%
7	Secondary Customers	C62Sec	100.00%	89.31%	10.26%	6.58%	3.68%	0.43%
8	Summer Peak Resp KW	D10S	100.00%	39.55%	60.45%	2.77%	57.68%	0.00%
9	Transmission Demand %	D10T	100.00%	38.73%	60.94%	2.85%	58.09%	0.33%
10	Winter Peak Resp KW	D10W	100.00%	37.53%	61.66%	2.97%	58.69%	0.81%
11	Alternative Production Allocator	1CP	100.00%	39.55%	60.45%	2.77%	57.68%	0.00%
12	Sec, Pri & TT, Class Coin kW @ :	D60Sub	100.00%	42.36%	57.05%	2.91%	54.14%	0.59%
13	Sec & Pri, Cl Coin kW (no Min Sy	D61PS	100.00%	37.77%	61.88%	2.44%	59.45%	0.34%
14	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	100.00%	75.58%	23.92%	2.75%	21.17%	0.50%
15	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	100.00%	74.87%	25.13%	2.05%	23.08%	0.00%
16	Sec, Class Coin kW (w/o Min Sys	D62SecL	100.00%	50.55%	49.19%	3.07%	46.13%	0.26%
17	Direct Assign Street Lighting	DASL	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%
18	On + Off Sales MWH	E8760	100.00%	31.69%	67.96%	2.94%	65.03%	0.35%
19	Street Lighting (Dir Assign)	P73	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%
20	MWh Sales Excl CIP Exempt	E99XCIP	100.00%	32.45%	67.09%	3.01%	64.081%	0.46%
21	Present Rev	R01	100.0000%	38.9341%	60.2304%	3.3882%	56.8422%	0.8355%
22	Late Fee Revenue Allocator	LateFee	100.00%	84.95%	14.99%	3.01%	11.98%	0.06%

			1=2+3+6	2	3=4+5	4	5	6
EXTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
23	Customers - B Basis	C10	1,363,310	1,217,095	140,329	89,656	50,674	5,886
24	Cust - Ave Monthly (C10-Area Lt)	C11	1,389,660	1,220,945	140,527	89,854	50,674	28,188
25	Mo Cus Wtd By Cus Acct	C11WA	1,449,527	1,220,945	223,830	116,810	107,021	4,752
26	Cust Acctg Wtg Factor	C11WAF	18.64	1.00	17.64	1.30	16.34	N/A
27	Cust-Ave Mo (C11 w/ Dir Assign :	C12	1,364,342	1,220,945	140,527	89,854	50,674	2,869
28	Mo Cus Wtd By Mtr Invest	C12WM	149,707,167	118,285,720	31,105,384	11,205,511	19,899,873	316,063
29	Meter Invest / Cust Factor	C12WMF	10,636	97	10,429	125	10,304	110
30	Sec & Pri Customers	C61PS	1,363,288	1,217,095	140,307	89,656	50,652	5,886
31	% Served by Primary Single Phase		0.0%	72.72%	0.00%	41.04%	0.00%	53.62%
32	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	931,261	885,051	43,054	36,798	6,256	3,156
33	C62Sec, w/o Ltg & C/I Undergrou	C62NL	1,283,386	1,217,095	66,292	42,508	23,784	0
34	Secondary Customers	C62Sec	1,362,800	1,217,095	139,820	89,656	50,164	5,886
35	Summer Peak Resp KW	D10S	33,113	13,097	20,016	917	19,099	0
36	Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	3,873,077	6,093,900	284,950	5,808,950	33,024
37	Winter Peak Resp KW	D10W	3,947	1,481	2,434	117	2,316	32
38	Alternative Production Allocator	1CP	33,113	13,097	20,016	917	19,099	0
39	Sec, Pri & TT, Class Coin kW @ :	D60Sub	6,076,291	2,573,772	3,466,447	176,924	3,289,523	36,072
40	Sec & Pri, Class Coin kW (w/o Mi	D61PS	5,407,775	2,042,778	3,346,490	131,742	3,214,748	18,507
41	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	1,965,516	1,485,474	470,119	54,072	416,047	9,923
42	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	11,147,420	8,346,037	2,801,383	228,808	2,572,575	0
43	Sec, Class Coin kW (w/o Min Sys	D62SecL	10,000,000	5,054,963	4,919,245	306,506	4,612,739	25,792
44	Annual Billing kW	D99	47,640.460	0	47,640	0	47,640	0
45	Summer Billing kW	D99S	17,268.243	0	17,268	0	17,268	0
46	Winter Billing kW	D99W	30,372.217	0	30,372	0	30,372	0
47	Non-Coinc Pk Second	DN-Sec	14,273,116	8,346,037	5,908,572	482,593	5,425,978	18,507
48	MWh Sales	E99	28,062,414	8,661,624	19,277,580	803,030	18,474,550	123,211
49	MWh Sales Excl CIP Exempt	E99XCIP	26,692,558	8,661,624	17,907,723	802,917	17,104,806	123,211

Tab No.	CCOSS Spreadsheet Tab Label	Spreadsheet Tab Description
1	CCOSS Summary	Shows a summary of CCOSS results; specifically Unadjusted Revenue Requirement, Adjusted Revenue Requirements and Revenue Deficiency are shown by Customer Class.
2	Err_Chk	Conducts error checking to insure costs and revenues are appropriately allocated to Cost Classification, Function, Subfunction and Customer Classes. Also insures the class subtotals are correct.
3	RR-TOT	Shows detailed revenue requirement calculations for all functions and cost classifications combined.
4	RR-CUS	Shows detailed revenue requirement calculations for costs that have been classified as Customer-Related. It includes the customer-related portion of primary and secondary distribution lines/transformers, service line costs, metering, meter reading, billing, customer service costs and costs of back office support. RR-Cus = RR-Svc_Drop + RR-En_Svc
5	RR-DMD	Shows detailed revenue requirement calculations for costs that have been classified as Demand-Related.
6	RR-ENE	Shows detailed revenue requirement calculations for costs that have been classified as Energy-Related. RR-ENE = RR-On + RR-Off
7	RR-Genco	Shows detailed revenue requirement calculations for costs that have been functionalized as being generation related. This includes all energy-related costs and all fixed production costs. RR-Genco = RR-ENE + RR-G_Dmd
8	RR-G_Dmd	Shows detailed revenue requirement calculations for all generation costs except those that are classified as Energy-Related. RR-G_Dmd = RR-Base + RR_Summ + RR_Wint
9	RR-Base	Shows detailed revenue requirement calculations for the fixed cost of generation plant investment and purchased capacity costs which have been stratified as Energy-Related.
10	RR-Summ	Shows detailed revenue requirement calculations for the fixed cost of generation plant investment and purchased capacity costs which have been stratified as Capacity-Related and are associated with the summer system peak load requirements.
11	RR-Wint	Shows detailed revenue requirement calculations for the fixed cost of generation plant investment and purchased capacity costs which have been stratified as Capacity-Related and are associated with the winter system peak load requirements.
12	RR-On	Shows detailed revenue requirement calculations for costs of fuel and purchases of energy for on-peal hours.
13	RR-Off	Shows detailed revenue requirement calculations for costs of fuel and purchases of energy for off-peal hours.
14	RR-Transco	Shows detailed revenue requirement calculations for the transmission function. It includes costs of transmission lines used to transport power from its origin generation stations or delivery points to the high voltage side of the distribution substations.
15	RR-Disco	Shows detailed revenue requirement calculations for the Distribution function. It includes costs of distribution substations and the capacity-related portion of primary and secondary distribution lines and transformers. RR-Disco = RR-Psub + RR-Prim + RR_Sec
16	RR-Psub	Shows detailed revenue requirement calculations for Distribution substations.
17	RR-Prim	Shows detailed revenue requirement calculations for the capacity-related portion of primary voltage conductors, transformers and related facilities.
18	RR-Sec	Shows detailed revenue requirement calculations for the capacity-related portion of secondary voltage conductors, transformers and related facilities.
19	RR-Svc_Drop	Shows detailed revenue requirement calculations for the customer-related portion of primary and secondary distribution lines/transformers, service line costs and metering.
20	RR_En_Svc	Shows detailed revenue requirement calculations for costs of meter reading, billing, customer service and costs of back office support.
21	JCOSS-Complete Revenue Requirement	Shows overall JCOSS cost of service results. Also shows a line-item comparison of selected revenue and cost items between the JCOSS and CCOSS models
22	JCOSS-Basic Inputs	Provides basic financial inputs from the Jurisdictional Cost of Service Study. Inputs include state and federal tax rates and capital structure inputs. Calculations are also included to insure JCOSS and CCOSS revenue requirement and deficiency results tie-out.
23	JCOSS-Detailed Inputs	Provides detailed JCOSS line item FERC code level inputs to the CCOSS model. All detailed rate base and expense related line items are provided in this tab.
24	JCOSS-Financial Details	Provides the derivation of line item details including base level data and all adjustments applied to derive the final JCOSS detailed inputs
25	JCOSS-Labels	Shows JCOSS line-item labels used in the Revenue Analysis RIS System
26	JCOSS-O&M for Labor	Has JCOSS O&M data for calculating the LABOR internal allocation factor that is used for allocating several cost items to customer class

Tab No.	CCOSS Spreadsheet Tab Label	Spreadsheet Tab Description
27	JCOSS-O&M Tags	Shows JCOSS line-item labels used in the Revenue Analysis RIS System that are used when calculating the LABOR internal allocation factor
28	JCOSS-Plant Stratified	Shows the results of the plant stratification analysis. Based on the Plant Stratification results, baseload versus peaking ratios are applied to various cost items that stratified
29	Alloc-Input Data	Provides external allocator data for input to the CCOSS model. Data is provided for all external allocators including production and transmission allocators, distribution capacity allocators and customer allocators.
30	Alloc-Prod Trans	Provides allocator calculations for all fixed production and transmission cost allocators. Note calculation of the D10S allocator is based on class hourly loads that are coincident with the forecasted MISO 2022 peak hour for Local Resource Zone 1.
31	Alloc-Dist Cap	Provides allocator calculations for all distribution costs that are capacity-related.
32	Alloc-Cust	Provides allocator calculations for all allocators that are used to allocate customer-related costs.
33	Alloc-E8760	Has the calculations for the E8760 energy allocation factor.
34	InputData-NSP Syst Hourly Loads	Has the TY2022 forecasted hourly loads for the NSP System. Also calculates the NSP System Load Factor
35	InputData-NSP Syst Hourly Loads Sorted	Has the TY2022 forecasted hourly loads for the NSP System do deterime what class hourly loads should be induded for calculating the D10S capacity allocatio factor
36	InputData-8760 Loads	Has TY2022 Minnesota forecasted hourly loads by customer class. Hourly loads are shown with and without load management. This tab also shows monthly system coincident and class coincident peaks by customer class. Summaries are shown with and without load management.
37	InputData-E8760	Has the hourly load data and hourly marginal energy costs for calculating the E8760 allocator. The hourly loads used in the calcultion of the E8760 allocator assume no load management
38	InputData-Cust Max kW	Based on a query of the customer billing system has the sum of individual customer maximum actual demands by customer class for demand billed customers. Loss factors are applied to these quantities. For the customer classes that are not demand billed, the data is provided by the Load Research Dept. These quanitites are used in calculating certain distribution capacity allocators.
39	InputData-Cust Fcst	Has the results of the 2022 customer forecast by customer class. These results were used in calculation allocation factors for customer-related costs.
40	InputData-kWh Sales Fcst	Has the results of the 2022 kWh sales forecast by customer class.
41	InputData-kWh Fcst CIP Exmpt	Has the sales forecast for CIP exempt customers. When allocating CIP costs these sales are excluded when calculating the CIP cost allocation factor.
42	InputData-Summ Wint	Has the NSP System monthly peaks that are used to are used to split Production Capacity costs into summer and winter seasons.
43	InputData-OthProdOM	Has the split of Other Production O&M costs into energy-related and capacity-related components using the "Location" method.
44	InputData-PlantStrat2021	Has the plant stratification analysis results. These peaking versus baseload results were applied as shown on the "JCOSS-Plant Stratified" and "InputData-OthProdOM" tabs.
45	InputData-MeterCost	Has average metering costs by customer class. Metering costs include the cost of meters, current transformers and voltage transformers. These costs were used in calculating the meter cost allocation factor.
46	InputData-Dist1Ph3Ph	Shows the percent of customers that are served off 3 phase primary distribution lines versus 1 phase distribution lines.
47	InputData-OHUGSvc	Shows the results of the analysis that shows the percent of C&I customers that are served by an overhead versus underground service. C&I customers that are served by an underground service own the service and shouldn't be allocated these costs.
48	InputData-OHLtg	Shows the results of an analysis that quantifies the amount of pole p1ant investement that should be directly assigned to the lighting class.
49	InputData-PSHLMeters	Based on a query of the customer billing system, shows the number of street lighting meters that is used in the allocation of metering costs.
50	InputData-CustAcctgWt	Relative weighting by customer class for costs of meter reading, billing and collections and uncollectible accounts.
51	InputData-LateFees	Based on budgeted late fees for C&I versus Residential customers and a query of 2014 late fee revenues by customer class, provides an allocation factor for late fee revenues.
52	InputData-Trans Dist Direct kW	Based on the customers served by direct assignment distribution substations and transmission radials has customer maximum demands that should be excluded from the D60Sub allocator for customers in these classes are not double charged for distribution substation costs
53	InputData-Dist Cap Vs Cust	Based on the results of the Minimum System and Zero Intercept studies, shows how distribution plant investment should be split into capacity and customer-related components
54	InputData-2022 Present and Proposed	Has present and proposed revenues by customer class with and without load management discounts. Also has the amount of the economic development discounts by customer class.

Results of Xcel Energy Minimum Distribution System & Zero Intercept Studies

1. Overview

An important step in the Class Cost of Service Study (CCOSS) process is to classify costs according to one of the following billing components based on the nature of the cost:

1. Demand – Costs that are driven by customers' maximum kilowatt (kW) demand.
2. Energy – Costs that are driven by customers' energy or kilowatt-hours (kWh) requirements.
3. Customer – Costs that are related to the number of customers served.

For Distribution Plant Investment, costs are classified as being capacity or customer-related. Page 87 of the NARUC Electric Utility Cost Allocation Manual and Table 1 below shows how FERC classifies distribution plant by function and sub-function.

Table 1
FERC Classification of Distribution Plant Investment

	Cost Classification	
Function/Sub-Function	**Demand**	**Customer**
Distribution Substations	X	
Primary Transformers	X	
Primary Lines	X	X
Secondary Lines	X	X
Secondary Transformers	X	X
Service Drops		X

As shown in the table above, primary lines, secondary lines and secondary transformers are classified as both "demand" and "customer" related costs. Costs of these sub-functions are driven by **both** the number of customers on the distribution system and the capacity requirements they place on the system.

The Minimum System and Zero Intercept methods are two widely used methods for determining the percent of distribution plant investment that is customer-related and allocated to class with a customer based allocation factor, versus the percent of costs that are capacity-related and allocated to class with a demand based allocator. These methods are described on pages 86-96 of the NARUC Electric Utility Cost Allocation Manual.

The Company has used the Minimum System method to do this classification for distribution plant investment in its rate cases since the 1990s. As part of its order from the Company's 2013 rate case, the Commission ordered the Company to update its minimum system study, and attempt to conduct a zero intercept study providing it can obtain the necessary data. This exhibit describes the steps the Company has taken to fulfill this requirement.

2. Steps for Completing a Minimum System Study

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 that are 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 plat it 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 balance being the capacity-related portion.

The assumed minimum property unit configurations used in the minimum system study are shown in Company witness Ms. Kelly A. Bloch's testimony.

3. Steps for Completing a Zero Intercept Study

The steps for completing a zero or minimum intercept are described on pages 92-94 of the NARUC manual. A zero intercept study requires considerable 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 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.

After the above data is acquired, the following analysis 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.

4. Minimum System and Zero Intercept Data Sources

The data sources used to complete both studies are described in detail in Ms. Bloch's direct testimony. In short, data on the types, configurations, sizes and quantities of distribution equipment were obtained by querying the Company's Geographic Information System (GIS). Data on the installed unit costs for each equipment configuration were obtained by analyzing the costs distribution work orders that were completed from 2007-2018. The goal in this data gathering step was to obtain installed costs for equipment configuration that comprise 90% of the population for a given property unit (i.e. underground primary conductor).

5. Analysis Results

The data and results of the minimum system and zero intercept studies are shown in Attachments A to P of Schedule 11.

Attachments A to F show the inventory of the different equipment configurations for each property unit.

Attachment G shows the inventory of primary voltage distribution transformers. As shown in Table 1 above, there is no customer component to this property unit. Attachment G also shows the installed cost per unit and total replacement cost for primary voltage transformers so that transformer plant investment can be separated into primary and secondary voltages.

Attachments H through M show the graphical results of the zero intercept linear regression analysis for each property unit.

Attachment N shows the detailed minimum system and zero intercept calculations.

- Column 1: Lists the property unit.
- Column 2: For primary conductor, indicates if it's 1 phase or 3 phase.
- Column 3: Lists the specific configuration of the equipment.
- Column 4: Lists the inventory of the equipment configuration.
- Column 5: Shows the percent of total equipment total inventory that the specific configuration makes up.
- Column 6: Shows the cumulative percent of inventory that the configuration included in the study make up. As shown in Column 6, the Distribution Engineering area provided cost data for equipment configurations that make up 90% of the total inventory for a given property unit.
- Column 7: Shows the load carrying capacity of the given equipment configuration.
- Column 8: Shows the per unit installed cost as determined by the Distribution Engineering area.
- Column 9: Calculates the total cost of each equipment configuration by multiplying its equipment inventory in Column 4 by the per unit installed cost in Column 8. This result is summed across all equipment configurations to provide total installed costs for a given property unit.
- Column 10: Shows the cost per unit that was determined using the zero intercept method. This was determined by conducting a linear regression analysis using load carrying capacity (in Column 7) as the independent variable, with cost per unit (in Column 8) as the dependent variable.

- Column 11: Calculates total cost of each equipment configuration assuming the zero intercept cost is the cost per unit for all equipment configurations. The equipment inventory in Column 4 is multiplied by the zero intercept cost in Column 10. This result is summed across all equipment configurations to provide total cost for a given property unit, assuming the zero intercept cost is the cost for all equipment configurations. This total for a given property unit divided by the same total in Column 9 is the percent of costs that should be classified as customer-related using the zero intercept approach.
- Column 12: Shows the per unit installed cost of the minimum sized equipment configuration.
- Column 13: Calculates total cost of each equipment configuration assuming the cost of minimum system equipment configuration is the cost per unit for all equipment configurations. The equipment inventory in Column 4 is multiplied by the cost of the minimum system unit in Column 12. This result is summed across all equipment configurations to provide total cost for a given property unit assuming the cost of the minimum system unit is the cost for all equipment configurations. This total for a given property unit divided by the same total in Column 9 is the percent of costs that should be classified as customer-related using the minimum system approach.

Table 2 below shows the percent of costs that would be classified as customer related using the minimum system method compared to the zero intercept method. As shown in Table 2, for 4 of the 6 property units the zero intercept method provided a lower customer component, while 2 of the 6 have a lower customer component using the minimum system method.

Table 2
Percent of Distribution Plant Investment Classified as Customer-Related
Zero Intercept Method vs. the Minimum System Method

Property Unit	% of Costs Classified as Customer-Related	
	Zero Intercept Method	**Minimum System Method**
Overhead Primary	35.3%	63.7
Overhead Secondary	78.6%	99.2%
Overhead Transformers	73.5%	77.4%
Underground Primary	53.0%	62.3%
Underground Secondary	59.6%	100%
Underground Transformers	87.0%	51.6%

6. Application of Minimum System and Zero Intercept Results to Distribution Plant Investment

For a given property unit the Company used a “hybrid” of the two methods by applying the result that provided the lowest customer component as shown in Table 3 below.

Table 3
Customer vs. Capacity Classification Applied to Distribution Plant Investment

Property Unit	% Classified as Customer-Related	% Classified as Capacity-Related
Overhead Primary (used Zero Intercept result)	35.3%	64.7%
Overhead Secondary (used Zero Intercept result)	78.6%	21.4%
Underground Primary (used Zero Intercept result)	53.0%	47.0%
Underground Secondary (used Zero Intercept result)	59.6%	40.4%
Weighted Average for Overhead and Underground Transformers (used Zero Intercept for OH Transformers; used Minimum System for UG Transformers)	66.3%	33.7%

Attachment O of Schedule 11 shows how the above results from the minimum system and zero intercept analyses are used to provide the needed cost separations.

The first step is to multiply the total inventory of each property unit (shown in Column 1) by the overall cost per unit (shown in Column 2) to provide the total replacement cost (shown in Column 3). The total replacement costs for each property unit are shown in percentages in Column 4.

These percentages are then applied to the Total Test Year Plant in Service as provided from the Jurisdictional Cost of Service Study (JCOSS) to separate costs into sub-function. The Total Test Year Plant in Service from the JCOSS is shown in Attachment O on line 11, column 5 for Overhead Distribution Plant; on line 22, column 5 for Underground Distribution Plant; and on line 27, column 5 for transformers. (Note that the cost of Overhead Distribution Plant that is directly assigned to the Lighting class was quantified as shown on Table 12 on Page 32). For Overhead Distribution Line, the result as shown in Column 5 is a separation of Overhead Plant in Service costs into the following sub-functions:

- Overhead Primary Single Phase Lines (line 3)
- Overhead Primary Multi Phase Lines (line 6)
- Overhead Secondary Lines (line 9)
- Lighting (line 10)

For Underground Lines, there was no direct assignment to the Lighting class. The result as shown in Column 5 is a separation of Underground Plant in Service costs into the following sub-functions:

- Underground Primary Single Phase Lines (line 14)
- Underground Primary Multi Phase Lines (line 17)
- Underground Secondary Lines (line 20)

For Transformers, the result shown in Column 5 is a separation of Plant in Service costs into the following sub-functions:

- Primary Voltage Transformers (line 23)
- Secondary Voltage Transformers (line 26)

The final step as shown in Column 7 of Attachment O, was to apply the associated Customer & Capacity percentages as shown in Column 6 of Attachment O to the corresponding Plant in Service costs as shown in Column 5. The final result in Column 7 is a separation of distribution plant costs into sub-function and cost classification. These are the inputs to the CCOSS model for the 2021 test year as shown in Schedule 4, page 4, column 1, lines 19 – 42.

7. Distribution Service Drops

Although FERC (as shown in Table 1) and many utilities classify distribution services as only being customer-related, the Company has split these costs into capacity and customer-related components. The Company does not have detailed property records on the configuration or footage of distribution service drops. As such, it was not possible to conduct a detailed minimum system or zero intercept studies as described above. As a substitute a simplified minimum system analysis was conducted as shown in Attachment P.

Column 2 of Attachment P lists the minimum conductor configuration used by the Company in Overhead and Underground applications.

In column 3 we assumed a minimum footage per service of 50 feet.

In order to the get an estimated cost per foot for each conductor configuration, staff in the Distribution Design ran a number of service installation work orders through the Company's distribution design software. The resulting unit costs are shown in column 4.

The Total Installed Costs for minimum service drop configuration as shown in column 6 is obtained by multiplying the Minimum Service Footage (column 3) by the Unit Cost per Foot (column 4) by the number of customers with overhead or underground services (column 5). The total minimum installed cost (column 6 total) is divided by total plant investment for distribution services (column 7). This is percent of distribution service costs that was classified as customer-related as shown in column 8.

8. Load carrying Capacity of Minimum System Design

The Company used the same 1.5 kW per customer for the load carrying capacity of the minimum system design. This is the same assumption that was made in the last rate case. This adjustment was applied to the distribution capacity cost allocation factors.

Inventory of Underground Primary by Conductor Configuration

Phase	Configuration Details Underground Primary	Footage	% of 1 Phase Footage	Cumulative % of 1 Phase Footage	% of All UG Primary	Cumulative % of All UG Primary
1 Phase	1/0 AL 1ph	16,001,972	51.54%	51.54%	28.98%	28.98%
	2 AL 1ph	14,328,983	46.16%	97.70%	25.95%	54.93%
	1 AL 1ph	263,202	0.85%	98.55%	0.48%	55.40%
	1/0 Unknown 1ph	236,582	0.76%	99.31%	0.43%	55.83%
	Unknown AL 1ph	78,811	0.25%	99.56%	0.14%	55.97%
	Unknown Unknown 1ph	47,326	0.15%	99.72%	0.09%	56.06%
	2 Unknown 1ph	34,983	0.11%	99.83%	0.06%	56.12%
	1/0 CU 1ph	17,418	0.06%	99.88%	0.03%	56.15%
	2/0 AL 1ph	9,262	0.03%	99.91%	0.02%	56.17%
	2 CU 1ph	6,086	0.02%	99.93%	0.01%	56.18%
	Unknown CU 1ph	4,504	0.01%	99.95%	0.01%	56.19%
	4/0 AL 1ph	4,020	0.01%	99.96%	0.01%	56.20%
	1/0 N/A 1ph	2,616	0.01%	99.97%	0.00%	56.20%
	Footage of 15 Remaining 1 Phase Underground Primary Conductor Configurations	9,451	0.03%	100.00%	0.02%	56.22%
	Total 1 Phase	**31,045,217**	**100.00%**		**56.22%**	

Phase	Config Details Underground Primary	Footage	% of 3 Phase Footage	Cumulative % of 3 Phase Footage	% of All UG Primary	Cumulative % of All UG Primary
3 Phase	1/0 AL 3ph	13,798,626	57.07%	57.07%	24.99%	24.99%
	750 AL 3ph	4,716,848	19.51%	76.58%	8.54%	33.53%
	2 AL 3ph	1,079,318	4.46%	81.05%	1.95%	35.48%
	600 CU 3ph	881,596	3.65%	84.69%	1.60%	37.08%
	500 CU 3ph	745,916	3.09%	87.78%	1.35%	38.43%
	1000 AL 3ph	541,370	2.24%	90.02%	0.98%	39.41%
	500 AL 3ph	465,879	1.93%	91.94%	0.84%	40.25%
	750 CU 3ph	416,228	1.72%	93.67%	0.75%	41.01%
	1/0 Unknown 3ph	319,734	1.32%	94.99%	0.58%	41.59%
	1/0 CU 3ph	285,399	1.18%	96.17%	0.52%	42.10%
	Unknown Unknown 3ph	174,882	0.72%	96.89%	0.32%	42.42%
	4/0 CU 3ph	150,149	0.62%	97.51%	0.27%	42.69%
	500 Unknown 3ph	134,458	0.56%	98.07%	0.24%	42.94%
	1 AL 3ph	133,781	0.55%	98.62%	0.24%	43.18%
	350 CU 3ph	122,355	0.51%	99.13%	0.22%	43.40%
	400 CU 3ph	61,020	0.25%	99.38%	0.11%	43.51%
	750 Unknown 3ph	27,563	0.11%	99.50%	0.05%	43.56%
	Unknown AL 3ph	22,964	0.09%	99.59%	0.04%	43.60%
	2 Unknown 3ph	22,566	0.09%	99.68%	0.04%	43.64%
	4/0 Unknown 3ph	20,395	0.08%	99.77%	0.04%	43.68%
	600 Unknown 3ph	13,643	0.06%	99.82%	0.02%	43.70%
	350 AL 3ph	6,241	0.03%	99.85%	0.01%	43.72%
	Footage of 18 Remaining 3 Phase Underground Primary Conductor Configurations	36,272	0.15%	100.00%	0.07%	43.78%
	Total 3 Phase	**24,177,202**	**100.00%**		**43.78%**	
	Total 1 and 3 Phase	**55,222,420**			**100.00%**	

Inventory of Underground Secondary by Conductor Configuration

Configurateion Details Underground Secondary	Total Footage	% of UG Secondary	Cumulative % UG Secondary
6 AL Duplex	10,661,412	37.98%	37.98%
4/0 AL Triplex	8,422,109	30.01%	67.99%
2/0 AL Triplex	2,703,807	9.63%	77.62%
1/0 AL Triplex	1,572,271	5.60%	83.22%
6 CU Open Wire	1,230,243	4.38%	87.61%
350 AL Triplex	574,237	2.05%	89.65%
2 AL Triplex	300,574	1.07%	90.72%
6 CU Triplex	284,059	1.01%	91.73%
8 CU Open Wire	272,950	0.97%	92.71%
4 CU Open Wire	225,485	0.80%	93.51%
6 AL Triplex	224,454	0.80%	94.31%
8 CU Triplex	179,091	0.64%	94.95%
4 CU Triplex	137,219	0.49%	95.44%
Unknown Unknown Unknown	134,065	0.48%	95.91%
4 CU Duplex	77,150	0.27%	96.19%
4 CU N/A	64,053	0.23%	96.42%
2 Unknown Triplex	59,504	0.21%	96.63%
4 AL Triplex	54,038	0.19%	96.82%
2 Unknown Open Wire	53,905	0.19%	97.01%
6 CU N/A	53,212	0.19%	97.20%
2 AL Unknown	49,334	0.18%	97.38%
6 AL Unknown	46,776	0.17%	97.55%
4/0 AL Unknown	42,607	0.15%	97.70%
4/0 AL Quadraplex	39,730	0.14%	97.84%
2 Unknown Duplex	33,624	0.12%	97.96%
2 AL Duplex	30,790	0.11%	98.07%
8 AL Triplex	28,714	0.10%	98.17%
8 CU Duplex	27,997	0.10%	98.27%
6 CU Quadraplex	27,589	0.10%	98.37%
6 CU Unknown	20,379	0.07%	98.44%
6 CU Duplex	19,604	0.07%	98.51%
0 0 Unknown	19,429	0.07%	98.58%
0 0 Triplex	18,943	0.07%	98.65%
4/0 AL Duplex	18,612	0.07%	98.71%
Unknown Unknown Triplex	18,102	0.06%	98.78%
500 CU Quadraplex	17,845	0.06%	98.84%
0 0 Duplex	17,325	0.06%	98.90%
8 CU N/A	15,044	0.05%	98.96%
Unknown Unknown Duplex	13,483	0.05%	99.01%
6 AL Open Wire	12,567	0.04%	99.05%
Footage of 109 Remaining Underground Secondary Conductor Configurations	266,465	0.95%	100.00%
	28,068,796	100.00%	

Inventory of Underground Transformers by Transformer Configuration

Configuration Details 1 Phase Underground Transformers	Number of Transformers	1 Phase %	Cumulative Percent of 1 Phase Transformers	% of All Underground Transformers	Cumulative Percent of All Transformers
1 Phase Wye 50 kVA	27,634	45.47%	45.47%	32.31%	32.31%
1 Phase Wye 25 kVA	18,283	30.08%	75.56%	21.38%	53.69%
1 Phase Wye 37.5 kVA	9,017	14.84%	90.39%	10.54%	64.23%
1 Phase Wye 15 kVA	2,399	3.95%	94.34%	2.81%	67.04%
1 Phase Wye 100 kVA	1,317	2.17%	96.51%	1.54%	68.58%
1 Phase Wye 75 kVA	1,264	2.08%	98.59%	1.48%	70.06%
1 Phase Wye 10 kVA	304	0.50%	99.09%	0.36%	70.41%
1 Phase Wye 167 kVA	206	0.34%	99.43%	0.24%	70.65%
1 Phase Wye 50.0 kVA	163	0.27%	99.69%	0.19%	70.84%
1 Phase Wye 0 kVA	102	0.17%	99.86%	0.12%	70.96%
1 Phase Wye 25.0 kVA	33	0.05%	99.92%	0.04%	71.00%
1 Phase Wye 250 kVA	15	0.02%	99.94%	0.02%	71.02%
1 Phase Wye Unknown kVA	6	0.01%	99.95%	0.01%	71.03%
1 Phase Wye 112 kVA	4	0.01%	99.96%	0.00%	71.03%
1 Phase Wye 15.0 kVA	3	0.00%	99.96%	0.00%	71.03%
1 Phase Wye 150 kVA	3	0.00%	99.97%	0.00%	71.04%
1 Phase Wye 35 kVA	3	0.00%	99.97%	0.00%	71.04%
1 Phase Wye 20 kVA	2	0.00%	99.98%	0.00%	71.04%
1 Phase Wye 7 kVA	2	0.00%	99.98%	0.00%	71.05%
1 Phase Wye 75.0 kVA	2	0.00%	99.98%	0.00%	71.05%
1 Phase Wye 87.5 kVA	2	0.00%	99.99%	0.00%	71.05%
1 Phase Delta 50 kVA	1	0.00%	99.99%	0.00%	71.05%
1 Phase Wye 10.0 kVA	1	0.00%	99.99%	0.00%	71.05%
1 Phase Wye 100.0 kVA	1	0.00%	99.99%	0.00%	71.05%
1 Phase Wye 167.0 kVA	1	0.00%	99.99%	0.00%	71.06%
1 Phase Wye 225 kVA	1	0.00%	99.99%	0.00%	71.06%
1 Phase Wye 3 kVA	1	0.00%	99.99%	0.00%	71.06%
1 Phase Wye 333 kVA	1	0.00%	100.00%	0.00%	71.06%
1 Phase Wye 45 kVA	1	0.00%	100.00%	0.00%	71.06%
1 Phase Wye 5 kVA	1	0.00%	100.00%	0.00%	71.06%
1 Phase Wye 750 kVA	1	0.00%	100.00%	0.00%	71.06%
Number of Transformers for 18 Remaining Single Phase Transformer Configurations	52	0	0.08%	0.06%	
Total 1 Phase Transformers	60,774	1	100.00%	71.06%	

Configuration Details 2 Phase Underground Transformers	Number of Transformers	2 Phase %	Cumulative Percent of 2 Phase Transformers	% of All UG Transformers	Cumulative Percent of All Transformers
2 Phase Wye/Delta 75 kVA	280	31.22%	31.22%	0.33%	71.39%
2 Phase Wye/Delta 125 kVA	174	19.40%	50.61%	0.20%	71.59%
2 Phase Wye/Delta 204.5 kVA	110	12.26%	62.88%	0.13%	71.72%
2 Phase Wye/Delta 300 kVA	61	6.80%	69.68%	0.07%	71.79%
2 Phase Wye/Delta 50 kVA	59	6.58%	76.25%	0.07%	71.86%
2 Phase Wye/Delta 100 kVA	38	4.24%	80.49%	0.04%	71.90%
2 Phase Wye/Delta 62.5 kVA	30	3.34%	83.84%	0.04%	71.94%
2 Phase Wye/Delta 30 kVA	21	2.34%	86.18%	0.02%	71.96%
2 Phase Wye/Delta 150 kVA	20	2.23%	88.41%	0.02%	71.99%
2 Phase Wye/Delta 87.5 kVA	13	1.45%	89.86%	0.02%	72.00%
Number of Transformers for 27 Remaining 2 Phase Transformer Configurations	91	10.14%	100.00%	0.11%	72.11%
Total 2 Phase Transformers	897	100.00%	100.00%	1.05%	

Inventory of Underground Transformers by Transformer Configuration

Configuration Details 3 Phase Underground Transformers	Number of Transformers	3 Phase %	Cumulative Percent of 3 Phase Transformers	% of All UG Transformers	Cumulative Percent of All Transformers
3 Phase Wye/Wye 150 kVA	3,764	15.78%	15.78%	4.40%	76.51%
3 Phase Wye/Wye 300 kVA	3,671	15.39%	31.17%	4.29%	80.80%
3 Phase Wye/Wye 75 kVA	3,535	14.82%	45.99%	4.13%	84.94%
3 Phase Wye/Wye 500 kVA	3,161	13.25%	59.25%	3.70%	88.63%
3 Phase Wye/Wye 112 kVA	2,030	8.51%	67.76%	2.37%	91.01%
3 Phase Wye/Wye 225 kVA	1,829	7.67%	75.43%	2.14%	93.14%
3 Phase Wye/Wye 750 kVA	1,812	7.60%	83.02%	2.12%	95.26%
3 Phase Wye/Wye 1000 kVA	1,361	5.71%	88.73%	1.59%	96.85%
3 Phase Wye/Wye 1500 kVA	1,145	4.80%	93.53%	1.34%	98.19%
3 Phase Wye/Wye 45 kVA	524	2.20%	95.73%	0.61%	98.81%
3 Phase Wye/Wye 2000 kVA	488	2.05%	97.77%	0.57%	99.38%
3 Phase Wye/Wye 2500 kVA	122	0.51%	98.29%	0.14%	99.52%
3 Phase Wye/Delta 300 kVA	26	0.11%	98.39%	0.03%	99.55%
3 Phase Wye/Delta 500 kVA	23	0.10%	98.49%	0.03%	99.58%
3 Phase Wye/Delta 150 kVA	18	0.08%	98.57%	0.02%	99.60%
3 Phase Wye/Wye 0 kVA	17	0.07%	98.64%	0.02%	99.62%
3 Phase Wye/Delta 225 kVA	16	0.07%	98.70%	0.02%	99.64%
3 Phase Wye/Wye 450 kVA	15	0.06%	98.77%	0.02%	99.65%
3 Phase Delta/Wye 500 kVA	14	0.06%	98.83%	0.02%	99.67%
3 Phase Open Wye/Open Delta 75 kVA	14	0.06%	98.88%	0.02%	99.69%
3 Phase Wye/Delta 75 kVA	14	0.06%	98.94%	0.02%	99.70%
3 Phase Wye/Wye 75.0 kVA	14	0.06%	99.00%	0.02%	99.72%
3 Phase Delta/Wye 300 kVA	12	0.05%	99.05%	0.01%	99.73%
3 Phase Wye/Wye 150.0 kVA	11	0.05%	99.10%	0.01%	99.75%
3 Phase Wye/Wye 750.0 kVA	11	0.05%	99.14%	0.01%	99.76%
3 Phase Wye/Wye 300.0 kVA	10	0.04%	99.19%	0.01%	99.77%
3 Phase Delta/Wye 1000 kVA	9	0.04%	99.22%	0.01%	99.78%
3 Phase Wye/Wye 50 kVA	9	0.04%	99.26%	0.01%	99.79%
3 Phase Wye/Wye 500.0 kVA	9	0.04%	99.30%	0.01%	99.80%
3 Phase Wye/Wye Unknown kVA	9	0.04%	99.34%	0.01%	99.81%
3 Phase Wye/Delta 112 kVA	8	0.03%	99.37%	0.01%	99.82%
3 Phase Delta/Wye 150 kVA	7	0.03%	99.40%	0.01%	99.83%
3 Phase Open Wye/Open Delta 125 kVA	7	0.03%	99.43%	0.01%	99.84%
3 Phase Wye/Wye 30 kVA	7	0.03%	99.46%	0.01%	99.85%
3 Phase Delta/Delta 300 kVA	6	0.03%	99.48%	0.01%	99.85%
3 Phase Delta/Wye 112 kVA	6	0.03%	99.51%	0.01%	99.86%
3 Phase Wye/Wye 100 kVA	6	0.03%	99.53%	0.01%	99.87%
3 Phase Wye/Wye 112.0 kVA	5	0.02%	99.56%	0.01%	99.87%
3 Phase Wye/Wye 15 kVA	5	0.02%	99.58%	0.01%	99.88%
3 Phase Wye/Wye 225.0 kVA	5	0.02%	99.60%	0.01%	99.89%
3 Phase Delta/Delta 150 kVA	4	0.02%	99.61%	0.00%	99.89%
3 Phase Delta/Wye 1500 kVA	4	0.02%	99.63%	0.00%	99.89%
3 Phase Delta/Wye 750 kVA	4	0.02%	99.65%	0.00%	99.90%
3 Phase Wye/Wye 333 kVA	4	0.02%	99.66%	0.00%	99.90%
3 Phase Delta/Delta 500 kVA	3	0.01%	99.68%	0.00%	99.91%
3 Phase Delta/Wye 225 kVA	3	0.01%	99.69%	0.00%	99.91%
3 Phase Wye/Delta 750 kVA	3	0.01%	99.70%	0.00%	99.91%
3 Phase Wye/Wye 1000.0 kVA	3	0.01%	99.71%	0.00%	99.92%
3 Phase Wye/Wye 25 kVA	3	0.01%	99.73%	0.00%	99.92%
3 Phase Wye/Wye 5000 kVA	3	0.01%	99.74%	0.00%	99.93%
3 Phase Delta/Delta 225 kVA	2	0.01%	99.75%	0.00%	99.93%
3 Phase Delta/Delta 750 kVA	2	0.01%	99.76%	0.00%	99.93%
3 Phase Delta/Wye 2000 kVA	2	0.01%	99.77%	0.00%	99.93%
3 Phase Open Wye/Open Delta 100 kVA	2	0.01%	99.77%	0.00%	99.93%
3 Phase Open Wye/Open Delta 150 kVA	2	0.01%	99.78%	0.00%	99.94%
3 Phase Open Wye/Open Delta 204.5 kVA	2	0.01%	99.79%	0.00%	99.94%

3 Phase Open Wye/Open Delta 50 kVA	2	0.01%	99.80%	0.00%	99.94%
3 Phase Open Wye/Open Delta 87.5 kVA	2	0.01%	99.81%	0.00%	99.94%
3 Phase Wye/Delta 1000 kVA	2	0.01%	99.82%	0.00%	99.95%
3 Phase Wye/Delta 2500 kVA	2	0.01%	99.82%	0.00%	99.95%
3 Phase Wye/Wye 115 kVA	2	0.01%	99.83%	0.00%	99.95%
3 Phase Wye/Wye 125 kVA	2	0.01%	99.84%	0.00%	99.95%
3 Phase Wye/Wye 1500.0 kVA	2	0.01%	99.85%	0.00%	99.96%
3 Phase Wye/Wye 167 kVA	2	0.01%	99.86%	0.00%	99.96%
3 Phase Delta/Delta 1000 kVA	1	0.00%	99.86%	0.00%	99.96%
3 Phase Delta/Delta 112 kVA	1	0.00%	99.87%	0.00%	99.96%
3 Phase Delta/Delta 15 kVA	1	0.00%	99.87%	0.00%	99.96%
3 Phase Delta/Delta 667 kVA	1	0.00%	99.87%	0.00%	99.96%
3 Phase Delta/Delta 75 kVA	1	0.00%	99.88%	0.00%	99.96%
3 Phase Delta/Wye 242 kVA	1	0.00%	99.88%	0.00%	99.96%
3 Phase Delta/Wye 450 kVA	1	0.00%	99.89%	0.00%	99.97%
3 Phase Delta/Wye 75 kVA	1	0.00%	99.89%	0.00%	99.97%
3 Phase Open Delta/Open Delta 75 kVA	1	0.00%	99.90%	0.00%	99.97%
3 Phase Open Wye/Open Delta 115 kVA	1	0.00%	99.90%	0.00%	99.97%
3 Phase Open Wye/Open Delta 200 kVA	1	0.00%	99.90%	0.00%	99.97%
3 Phase Open Wye/Open Delta 30 kVA	1	0.00%	99.91%	0.00%	99.97%
3 Phase Open Wye/Open Delta 40 kVA	1	0.00%	99.91%	0.00%	99.97%
3 Phase Open Wye/Open Delta 52.5 kVA	1	0.00%	99.92%	0.00%	99.97%
3 Phase Open Wye/Open Delta 62.5 kVA	1	0.00%	99.92%	0.00%	99.98%
3 Phase Wye/Delta 100 kVA	1	0.00%	99.92%	0.00%	99.98%
3 Phase Wye/Delta 1500 kVA	1	0.00%	99.93%	0.00%	
3 Phase Wye/Delta 30 kVA	1	0.00%	99.93%	0.00%	
3 Phase Wye/Delta 317 kVA	1	0.00%	99.94%	0.00%	
3 Phase Wye/Delta 367 kVA	1	0.00%	99.94%	0.00%	
3 Phase Wye/Delta 45 kVA	1	0.00%	99.95%	0.00%	
3 Phase Wye/Delta 50 kVA	1	0.00%	99.95%	0.00%	
3 Phase Wye/Delta 584 kVA	1	0.00%	99.95%	0.00%	
3 Phase Wye/Delta 833 kVA	1	0.00%	99.96%	0.00%	
3 Phase Wye/Wye 0.0 kVA	1	0.00%	99.96%	0.00%	
3 Phase Wye/Wye 105 kVA	1	0.00%	99.97%	0.00%	
3 Phase Wye/Wye 1250 kVA	1	0.00%	99.97%	0.00%	
3 Phase Wye/Wye 1667 kVA	1	0.00%	99.97%	0.00%	
3 Phase Wye/Wye 250 kVA	1	0.00%	99.98%	0.00%	
3 Phase Wye/Wye 35 kVA	1	0.00%	99.98%	0.00%	
3 Phase Wye/Wye 37.5 kVA	1	0.00%	99.99%	0.00%	
3 Phase Wye/Wye 45.0 kVA	1	0.00%	99.99%	0.00%	
3 Phase Wye/Wye 833 kVA	1	0.00%	100.00%	0.00%	
3 Phase Wye/Wye 900 kVA	1	0.00%	100.00%	0.00%	
Number of Transformers for 86 Remaining 3 Phase Transformer Configurations	409	1.71%	100.00%	0.48%	100.18%
Total 3 Phase Transformers	23,851	100.00%	100.00%	27.89%	
Total All Underground Transformers	**85,522**	3		100.00%	

Phase	Configuration Details Overhead Primary	Footage	% of 1 Phase Footage	Cumulative % of 1 Phase Footage	% of All OH Primary	Cumulative % of All OH Primary
1 Phase	4 ACSR 1ph	10,779,829	26.53%	26.53%	15.27%	15.27%
	2 ACSR 1ph	9,980,490	24.56%	51.10%	14.13%	29.40%
	6A CUWD 1ph	7,738,000	19.05%	70.14%	10.96%	40.36%
	6 CU 1ph	7,002,819	17.24%	87.38%	9.92%	50.27%
	3/10 CU 1ph	1,602,784	3.94%	91.32%	2.27%	52.54%
	Unknown Unknown 1ph	795,265	1.96%	93.28%	1.13%	53.67%
	4 CU 1ph	771,130	1.90%	95.18%	1.09%	54.76%
	2/0 ACSR 1ph	238,640	0.59%	95.77%	0.34%	55.10%
	3/8 CU 1ph	215,729	0.53%	96.30%	0.31%	55.41%
	6 CUWD 1ph	177,038	0.44%	96.73%	0.25%	55.66%
	8A CUWD 1ph	171,485	0.42%	97.15%	0.24%	55.90%
	2 CU 1ph	145,690	0.36%	97.51%	0.21%	56.11%
	1/0 ACSR 1ph	137,690	0.34%	97.85%	0.19%	56.30%
	Unknown CU 1ph	133,267	0.33%	98.18%	0.19%	56.49%
	130 Steel 1ph	81,915	0.20%	98.38%	0.12%	56.61%
	4A CUWD 1ph	74,567	0.18%	98.56%	0.11%	56.71%
	1/0 CU 1ph	67,793	0.17%	98.73%	0.10%	56.81%
	336 ACSR 1ph	58,453	0.14%	98.88%	0.08%	56.89%
	336 AL 1ph	52,357	0.13%	99.00%	0.07%	56.96%
	2/0 CU 1ph	40,322	0.10%	99.10%	0.06%	57.02%
	Footage of 62 Remaining Single Phase Overhead Primary Conductor Configurations	364,257	0.90%	100.00%	0.52%	57.54%
	Total 1 Phase	40,629,520	100.00%		57.54%	

Phase	Config Details OH Primary	Footage	% of 3 Phase Footage	Cumulative % of 3 Phase Footage	% of All OH Primary	Cumulative % of All OH Primary
3 Phase	336 AL 3ph	6,544,945	21.83%	21.83%	9.27%	66.81%
	2 ACSR 3ph	5,900,093	19.68%	41.50%	8.36%	75.16%
	336 ACSR 3ph	4,863,151	16.22%	57.72%	6.89%	82.05%
	2/0 ACSR 3ph	2,366,505	7.89%	65.61%	3.35%	85.40%
	4 ACSR 3ph	1,862,263	6.21%	71.82%	2.64%	88.04%
	6 CU 3ph	1,325,050	4.42%	76.24%	1.88%	89.91%
	4/0 CU 3ph	817,258	2.73%	78.97%	1.16%	91.07%
	1/0 ACSR 3ph	803,837	2.68%	81.65%	1.14%	92.21%
	6A CUWD 3ph	774,047	2.58%	84.23%	1.10%	93.30%
	Unknown Unknown 3ph	501,274	1.67%	85.90%	0.71%	94.01%
	4/0 ACSR 3ph	471,435	1.57%	87.48%	0.67%	94.68%
	556 AL 3ph	444,492	1.48%	88.96%	0.63%	95.31%
	4 CU 3ph	403,363	1.35%	90.30%	0.57%	95.88%
	556 ACSR 3ph	343,150	1.14%	91.45%	0.49%	96.37%
	3/8 CU 3ph	326,532	1.09%	92.54%	0.46%	96.83%
	3/10 CU 3ph	293,867	0.98%	93.52%	0.42%	97.25%
	336 AAC 3ph	284,217	0.95%	94.46%	0.40%	97.65%
	3/6 CU 3ph	234,864	0.78%	95.25%	0.33%	97.98%
	1/0 CU 3ph	228,648	0.76%	96.01%	0.32%	98.31%
	556 AAC 3ph	200,338	0.67%	96.68%	0.28%	98.59%
	2/0 CU 3ph	154,841	0.52%	97.19%	0.22%	98.81%
	2 CU 3ph	153,258	0.51%	97.71%	0.22%	99.03%
	336 CU 3ph	122,761	0.41%	98.11%	0.17%	99.20%
	2/0 AL 3ph	73,048	0.24%	98.36%	0.10%	99.30%
	Footage of 69 Remaining 3 Phase Overhead Primary Conductor Configurations	492,188	1.64%	100.00%	0.70%	100.00%
	Total 3 Phase	29,985,424	100.00%	42.46%	42.46%	
	Total All OH Primary	70,614,944				

Configuration Details Overhead Secondary	Total Footage	% of Total Overhead Secondary	Cumulative % Overhead Secondary
2 ACSR Open Wire	20,659,710	15.10%	15.10%
1/0 ACSR Open Wire	18,464,472	13.50%	28.60%
4 CU Open Wire	15,421,282	11.27%	39.88%
2 CU Open Wire	15,133,733	11.06%	50.94%
6 CU Open Wire	10,042,139	7.34%	58.29%
4 ACSR Open Wire	9,593,567	7.01%	65.30%
1/0 AL Triplex	7,529,615	5.51%	70.81%
6A CUWD Open Wire	6,529,682	4.77%	75.58%
1/0 AL Triplex, Lashed	6,462,163	4.72%	80.30%
6 ACSR Duplex	4,816,255	3.52%	83.83%
2 AL Triplex	2,563,679	1.87%	85.70%
1/0 CU Open Wire	2,553,956	1.87%	87.57%
3/10 CU Open Wire	1,561,406	1.14%	88.71%
6 AL Duplex	1,363,325	1.00%	89.71%
1/0 AL Open Wire	1,266,940	0.93%	90.63%
3/8 CU Open Wire	985,355	0.72%	91.35%
Unknown CU Open Wire	873,047	0.64%	91.99%
2 ACSR N/A	826,590	0.60%	92.60%
2/0 ACSR Open Wire	794,643	0.58%	93.18%
2 AL Open Wire	770,419	0.56%	93.74%
6 AL Triplex	684,735	0.50%	94.24%
1/0 ACSR Quadraplex	513,263	0.38%	94.62%
2 ACSR Neutral	485,021	0.35%	94.97%
2/0 ACSR Neutral	469,747	0.34%	95.31%
2 ACSR Triplex	424,986	0.31%	95.62%
2 ACSR Triplex, Lashed	347,685	0.25%	95.88%
1/0 ACSR Triplex, Lashed	309,720	0.23%	96.10%
3/6 CU Open Wire	240,780	0.18%	96.28%
4 ACSR Triplex	213,504	0.16%	96.44%
4/0 ACSR Quadraplex	203,353	0.15%	96.59%
4/0 AL Triplex	196,947	0.14%	96.73%
4/0 CU Open Wire	189,871	0.14%	96.87%
2/0 CU Open Wire	186,312	0.14%	97.00%
4 AL Open Wire	175,335	0.13%	97.13%
8A CUWD Open Wire	165,719	0.12%	97.25%
4 Unknown Open Wire	160,896	0.12%	97.37%
4A CUWD Open Wire	155,350	0.11%	97.49%
4 ACSR Duplex	125,641	0.09%	97.58%
0 0 Open Wire	120,451	0.09%	97.67%
1/0 ACSR Triplex	119,327	0.09%	97.75%
Footage of 361 Remaining Overhead Secondary Conductor Configurations	3,074,068	2.25%	100.00%
Total OH Secondary	136,774,689	100.00%	

Inventory of Overhead Transformers by Transformer Configuration

Config Details 1 Phase Overhead Transformers	Number of Transformers	1 Phase %	1 Phase Cumulative %	% of All Overhead Transformers	Cumulative Percent of All OH Transformers
1 Phase Wye 25 kVA	33,645	33.05%	33.05%	29.37%	29.37%
1 Phase Wye 10 kVA	18,868	18.53%	51.58%	16.47%	45.84%
1 Phase Wye 15 kVA	17,020	16.72%	68.30%	14.86%	60.70%
1 Phase Wye 37.5 kVA	16,272	15.98%	84.29%	14.20%	74.90%
1 Phase Wye 50 kVA	13,415	13.18%	97.46%	11.71%	86.61%
1 Phase Wye 75 kVA	806	0.79%	98.26%	0.70%	87.31%
1 Phase Wye 100 kVA	607	0.60%	98.85%	0.53%	87.84%
1 Phase Wye 5 kVA	412	0.40%	99.26%	0.36%	88.20%
1 Phase Wye 3 kVA	113	0.11%	99.37%	0.10%	88.30%
1 Phase Wye 0 kVA	108	0.11%	99.47%	0.09%	88.40%
1 Phase Wye 0.5 kVA	78	0.08%	99.55%	0.07%	88.46%
1 Phase Wye 25.0 kVA	66	0.06%	99.62%	0.06%	88.52%
Number of Transformers for 30 Remaining 1 Phase Transformer Configurations	391	0.38%	100.00%	0.34%	88.86%
Total 1 Phase Transformers	101,801	100.00%		88.86%	

Config Details 2 Phase Overhead Transformers	Number of Transformers	2 Phase %	2 Phase Cumulative %	% of All Overhead Transformers	Cumulative Percent of All OH Transformers
2 Phase Wye/Delta 40 kVA	5	16.13%	16.13%	0.00%	88.87%
2 Phase Wye/Delta 50 kVA	4	12.90%	29.03%	0.00%	88.87%
2 Phase Wye/Delta 75 kVA	4	12.90%	41.94%	0.00%	88.87%
2 Phase Wye/Delta 0 kVA	3	9.68%	51.61%	0.00%	88.88%
2 Phase Wye/Delta 30 kVA	3	9.68%	61.29%	0.00%	88.88%
2 Phase Wye/Delta 125 kVA	2	6.45%	67.74%	0.00%	88.88%
2 Phase Wye/Delta 25 kVA	2	6.45%	74.19%	0.00%	88.88%
2 Phase Wye/Delta 65 kVA	2	6.45%	80.65%	0.00%	88.89%
2 Phase Wye/Delta 100 kVA	1	3.23%	83.87%	0.00%	88.89%
2 Phase Wye/Delta 137.5 kVA	1	3.23%	87.10%	0.00%	88.89%
2 Phase Wye/Delta 150 kVA	1	3.23%	90.32%	0.00%	88.89%
2 Phase Wye/Delta 47.5 kVA	1	3.23%	93.55%	0.00%	88.89%
2 Phase Wye/Delta 62.5 kVA	1	3.23%	96.77%	0.00%	88.89%
2 Phase Wye/Delta 87.5 kVA	1	3.23%	100.00%	0.00%	88.89%
Number of Transformers for 6 Remaining 2 Phase Transformer Configurations	6	19.35%	100.00%	0.01%	88.89%
Total 2 Phase Transformers	31	100.00%		0.03%	

Config Details 3 Phase OH Transformers	Number of Transformers	3 Phase %	3 Phase Cumulative %	% of All OH Transformers	Cumulative Percent of All OH Transformers
3 Phase Wye/Wye 75 kVA	1,300	10.21%	10.21%	1.13%	90.03%
3 Phase Wye/Wye 150 kVA	1,034	8.12%	8.12%	0.90%	90.93%
3 Phase Wye/Wye 45 kVA	767	6.03%	6.03%	0.67%	91.60%
3 Phase Open Wye/Open Delta 75 kVA	733	5.76%	5.76%	0.64%	92.24%
3 Phase Wye/Wye 112 kVA	594	4.67%	4.67%	0.52%	92.76%
3 Phase Wye/Wye 300 kVA	506	3.98%	3.98%	0.44%	93.20%
3 Phase Open Wye/Open Delta 40 kVA	474	3.72%	3.72%	0.41%	93.61%
3 Phase Open Wye/Open Delta 35 kVA	405	3.18%	3.18%	0.35%	93.96%
3 Phase Open Wye/Open Delta 100 kVA	341	2.68%	2.68%	0.30%	94.26%
3 Phase Open Wye/Open Delta 62.5 kVA	333	2.62%	2.62%	0.29%	94.55%
3 Phase Open Wye/Open Delta 52.5 kVA	315	2.48%	2.48%	0.27%	94.83%
3 Phase Open Wye/Open Delta 65 kVA	314	2.47%	2.47%	0.27%	95.10%
3 Phase Wye/Wye 225 kVA	308	2.42%	2.42%	0.27%	95.37%
3 Phase Open Wye/Open Delta 20 kVA	307	2.41%	2.41%	0.27%	95.64%
3 Phase Open Wye/Open Delta 47.5 kVA	249	1.96%	1.96%	0.22%	95.86%
Number of Transformers for 168 Remaining 3 Phase Transformer Configurations	4,747	37.30%	39.26%	4.14%	100.00%
Total 3 Phase Transformers	12,727	100.00%		11.11%	
Total OH Transformers	114,559			100.00%	

Northern States Power Company

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Exhibit___(MAP-1), Schedule 10
Attachment G

Inventory of Primary Voltage Step-Down Transformers by Transformer Configuration

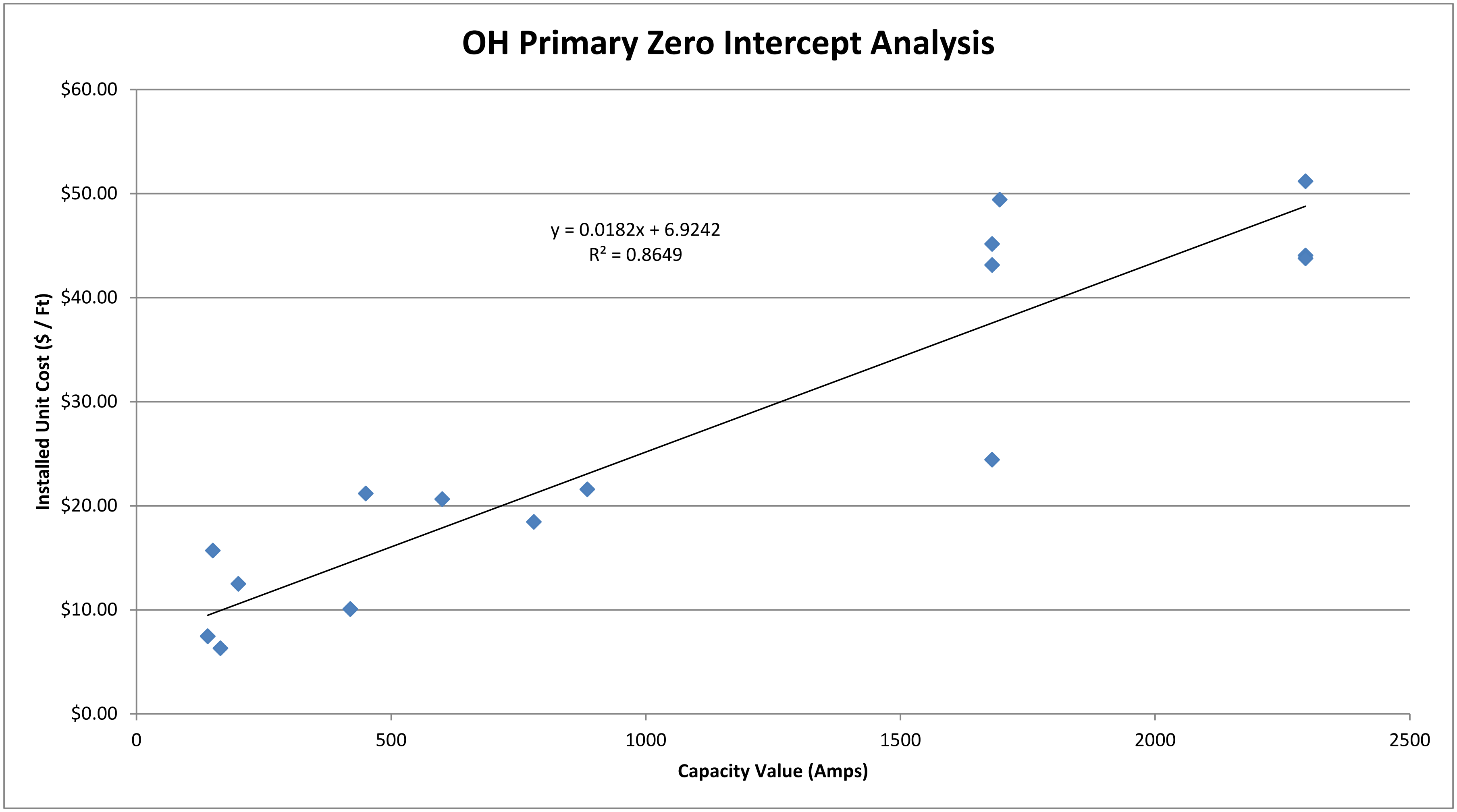
Overhead 1 Phase	Number OH 1 Phase	% of OH 1 Phase	Cumulative % of OH 1 Phase	% of All OH Step-Down Transformers	Load Carrying Capacity (kVA)	Installed Unit Cost	Total Replacement Costs
OH 1 phase 34.5/13.8 kV 500 kVA	170	17.14%	17.14%	12.36%	500	$44,094	$7,495,948
OH 1 phase 34.5/12.47 kV 500 kVA	98	9.88%	27.02%	7.13%	500	$44,095	$4,321,333
OH 1 phase 34.5/12.47 kV 50 kVA	81	8.17%	35.18%	5.89%	50	$10,067	$815,400
OH 1 phase 19.92/7.2 kV 167 kVA	66	6.65%	41.83%	4.80%	167	$22,743	$1,501,029
OH 1 phase 19.92/7.97 kV 50 kVA	53	5.34%	47.18%	3.85%	50	$10,067	$533,533
OH 1 phase 34.5/13.8 kV 250 kVA	62	6.25%	53.43%	4.51%	250	$31,030	$1,923,866
OH 1 phase 19.92/7.2 kV 100 kVA	46	4.64%	58.06%	3.35%	100	$20,005	$920,219
OH 1 phase 34.5/12.47 kV 333 kVA	57	5.75%	63.81%	4.15%	333	$37,814	$2,155,414
OH 1 phase 34.5/12.47 kV 250 kVA	46	4.64%	68.45%	3.35%	250	$31,029	$1,427,314
OH 1 phase 34.5/13.8 kV 333 kVA	46	4.64%	73.08%	3.35%	333	$37,814	$1,739,457
Number of Transformers and Cost of Transformers for 49 Remaining 1 Phase OH Transformer Configurations	**267**	**26.92%**		**18.15%**		$55,293.65	$14,763,405
Total OH 1 Phase	**992**	**100.00%**		**72.15%**		$37,900.12	$37,596,919

Overhead 2 Phase	Number OH 2 Phase	% of OH 2 Phase	Cumulative % of OH 2 Phase	% of All OH Step-Down Transformers	Load Carrying Capacity (kVA)	Installed Unit Cost	Total Replacement Costs
OH 2 phase 34.5/13.8 kV 1000 kVA	7	12.28%	12.28%	0.51%	1000	$66,139	$462,975
OH 2 phase 13.8/4.16 kV 500 kVA	4	7.02%	19.30%	0.29%	500	$28,550	$114,200
OH 2 phase 34.5/12.47 kV 1000 kVA	4	7.02%	26.32%	0.29%	1000	$66,139	$264,557
OH 2 phase 34.5/12.47 kV 500 kVA	4	7.02%	33.33%	0.29%	500	$46,543	$186,171
OH 2 phase 34.5/13.8 kV 200 kVA	4	7.02%	40.35%	0.29%	200	$24,850	$99,400
Number of Transformers and Cost of Transformers for 22 Remaining 2 Phase OH Transformer Configurations	**34**	**59.65%**		**2.47%**		$34,935	$1,187,796
Total OH 2 Phase	**57**	**100.00%**		**4.15%**		$40,616	$2,315,100

Overhead 3 Phase	Number OH 3 Phase	% of OH 3 Phase	Cumulative % of OH 3 Phase	% of All OH Step-Down Transformers	Load Carrying Capacity (kVA)	Installed Unit Cost	Total Replacement Costs
OH 3 phase 34.5/13.8 kV 1500 kVA	29	8.90%	8.90%	2.11%	1500	$81,703	$2,369,385
OH 3 phase 13.8/4.16 kV 1000 kVA	25	7.67%	16.56%	1.82%	1000	$56,982	$1,424,559
OH 3 phase 34.5/12.47 kV 1500 kVA	18	5.52%	22.09%	1.31%	1500	$81,706	$1,470,706
OH 3 phase 13.8/4.16 kV 500 kVA	14	4.29%	26.38%	1.02%	500	$33,865	$474,106
OH 3 phase 34.5/12.47 kV 1000 kVA	12	3.68%	30.06%	0.87%	1000	$70,068	$840,812
OH 3 phase 34.5/13.8 kV 500 kVA	11	3.37%	33.44%	0.80%	500	$42,141	$463,553
OH 3 phase 13.8/12.47 kV 1500 kVA	10	3.07%	36.50%	0.73%	1500	$93,865	$938,647
OH 3 phase 13.8/12.47 kV 5000 kVA	10	3.07%	39.57%	0.73%	5000	$305,750	$3,057,500
OH 3 phase 13.8/4.16 kV 1500 kVA	10	3.07%	42.64%	0.73%	1500	$66,715	$667,147
Number of Transformers and Cost of Transformers for 60 Remaining 3 Phase OH Transformer Configurations	**187**	**57.36%**		**13.60%**		$55,413	$10,362,271
Total OH 3 Phase	**326**	**100.00%**		**23.71%**		$67,695	**$22,068,685**
Total OH Step-Down Transformers	**1,375**					$45,077	$61,980,704

Underground 1 Phase	Number UG 1 Phase	% of UG 1 Phase	Cumulative % of UG 1 Phase	% of All UG Step-Down Transformers	Load Carrying Capacity (kVA)	Installed Unit Cost	Total Replacement Costs
UG 1 phase 19.92/7.2 kV 167 kVA	2	15.38%	15.38%	2.08%	167	$7,967	$15,933
UG 1 phase 19.92/7.97 kV 250 kVA	2	15.38%	30.77%	2.08%	250	$11,106	$22,211
UG 1 phase 19.92/7.97 kV 500 kVA	2	15.38%	46.15%	2.08%	500	$22,211	$44,422
Number of Transformers and Cost of Transformers for 7 Remaining 1 Phase UG Transformer Configurations	**7**	**53.85%**		**7.29%**		$12,338	$86,369
Total UG 1 Phase	**13**	**100.00%**		**13.54%**		$12,995	**$168,936**

Underground 3 Phase	Number UG 3 Phase	% of UG 3 Phase	Cumulative % of UG 3 Phase	% of All UG Step-Down Transformers	Load Carrying Capacity (kVA)	Installed Unit Cost	Total Replacement Costs
UG 3 phase 34.5/13.8 kV 5000 kVA	31	37.35%	37.35%	32.29%	5000	$194,366	$6,025,331
UG 3 phase 34.5/13.8 kV 3750 kVA	16	19.28%	56.63%	16.67%	3750	$381,179	$6,098,869
UG 3 phase 34.5/12.47 kV 5000 kVA	11	13.25%	69.88%	11.46%	5000	$194,366	$2,138,021
UG 3 phase 34.5/4.16 kV 11250 kVA	4	4.82%	74.70%	4.17%	11250	$1,143,538	$4,574,152
Number of Transformers and Cost of Transformers for 16 Remaining 3 Phase UG Transformer Configurations	**21**	**25.30%**		**21.88%**		$220,386	$4,628,103
Total UG 3 Phase	**83**	**100.00%**		**86.46%**		$282,705	**$23,464,476**
Total UG Step-Down Transformers	**96**						**$23,633,412**
All OH & UG Primary Step-Down Transfo	**1,471**					$58,201	**$85,614,116**


OH Primary Zero Intercept Analysis
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$50.00
$40.00
$30.00
$20.00
$10.00
$0.00
Installed Unit Cost ($ / Ft)
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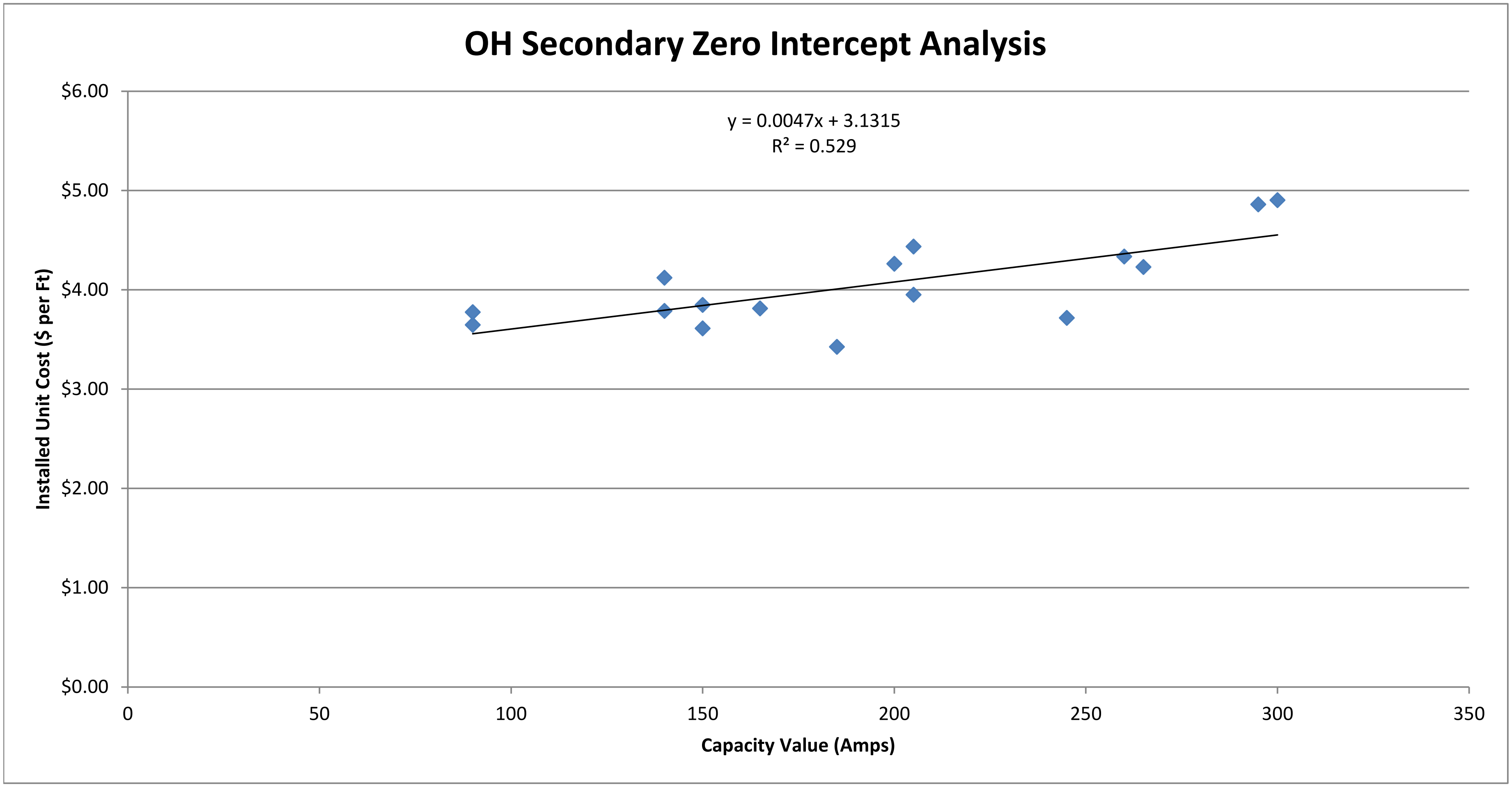
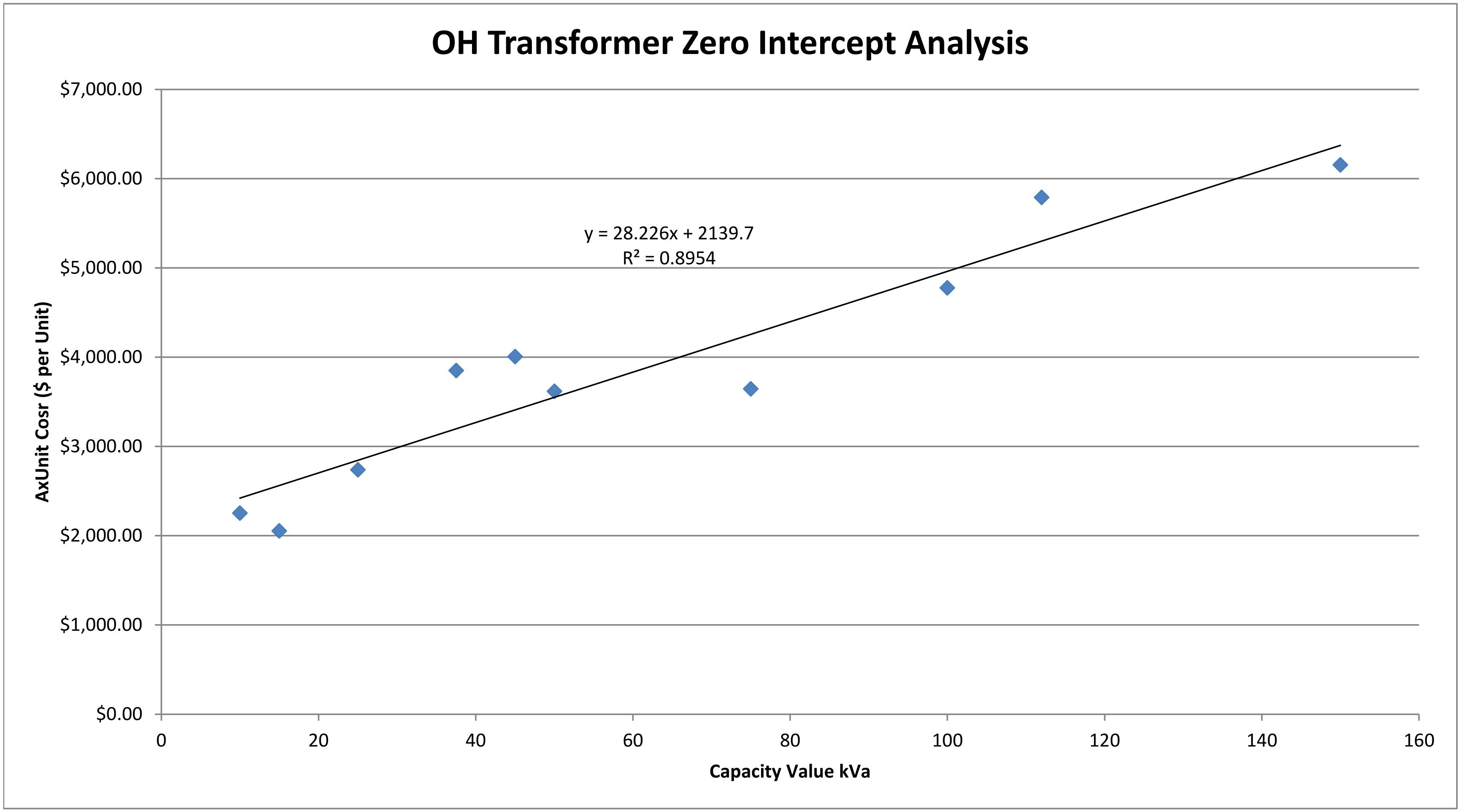
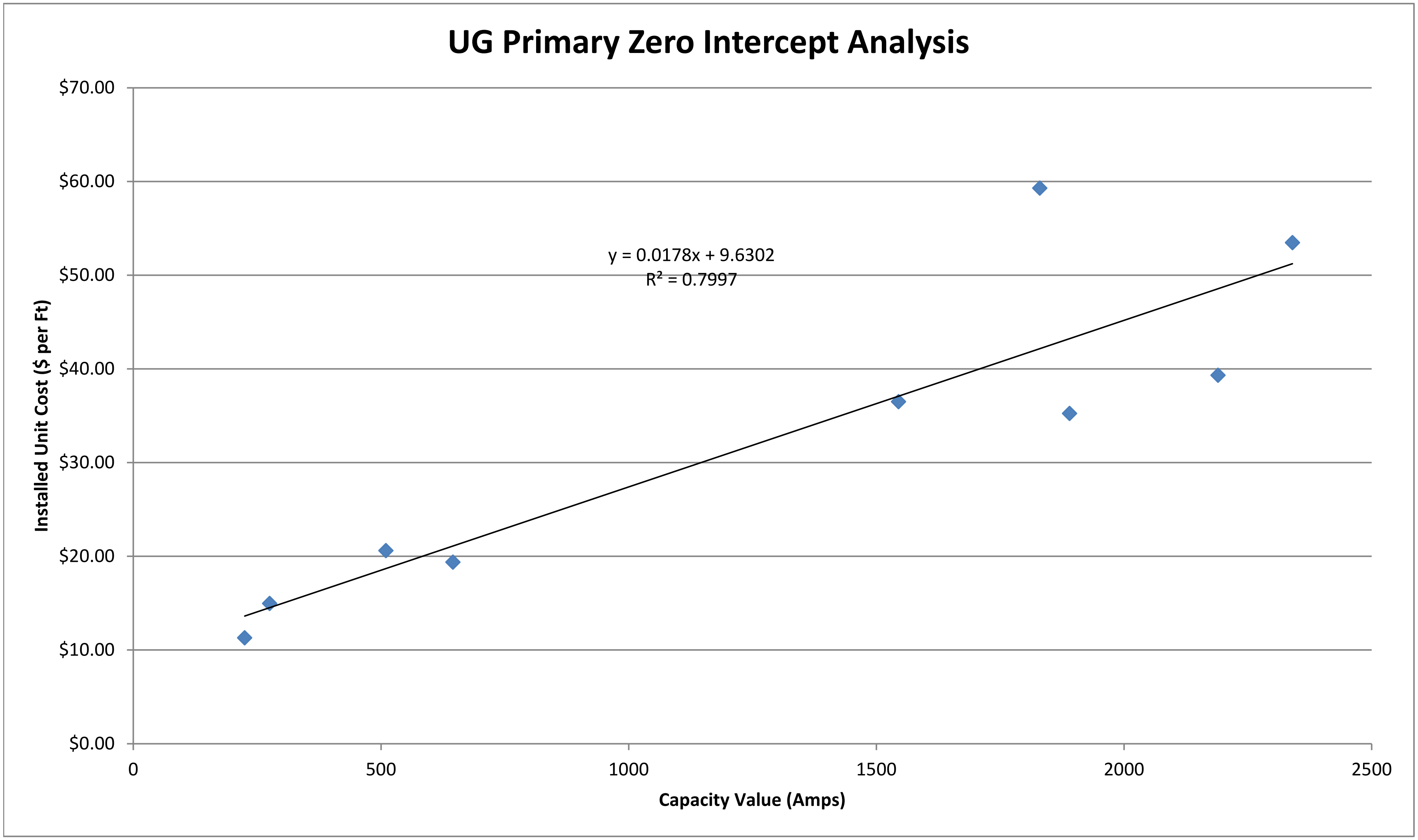
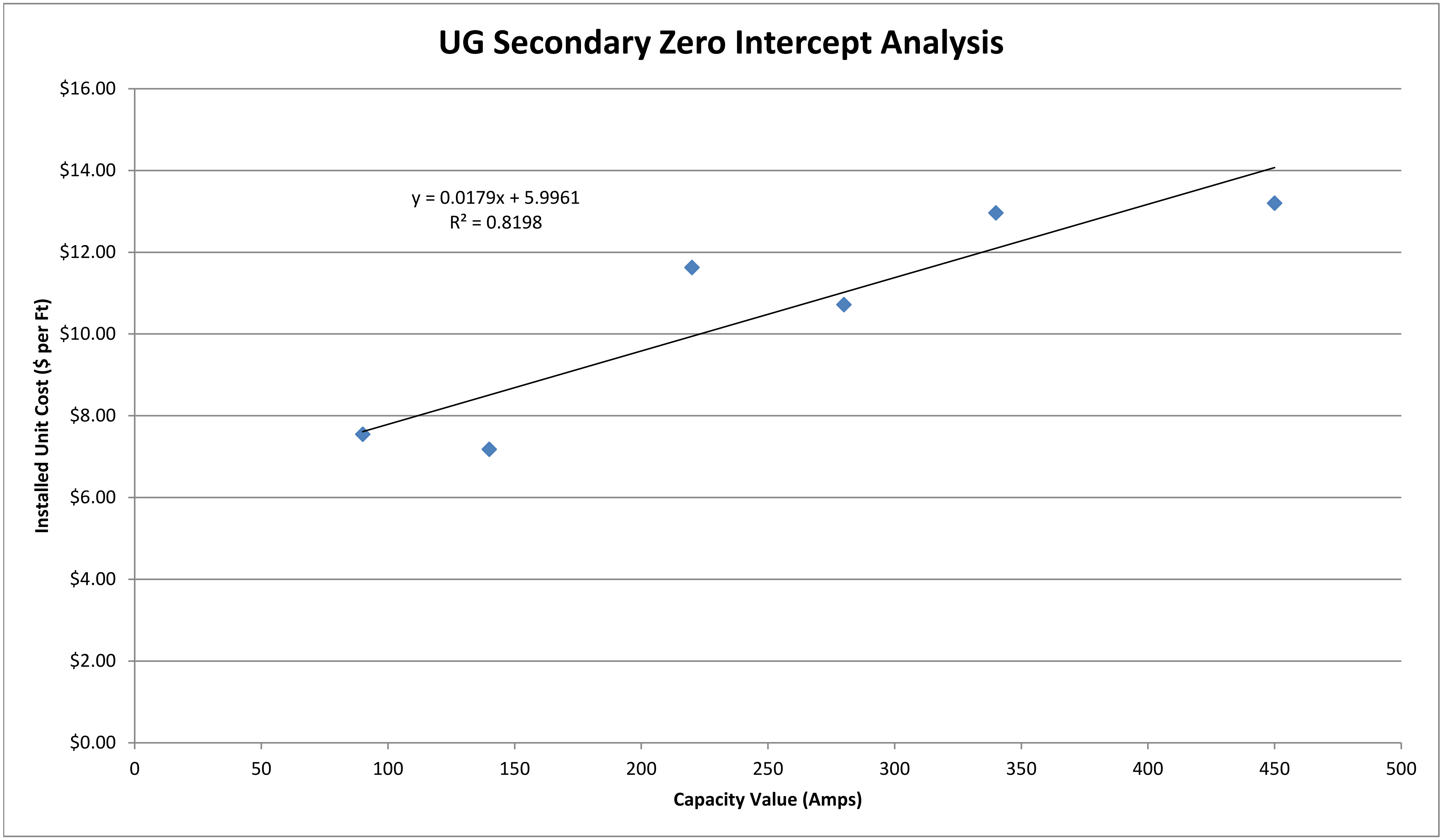
R² = 0.8649
0
500
1000
1500
2000
2500
Capacity Value (Amps)

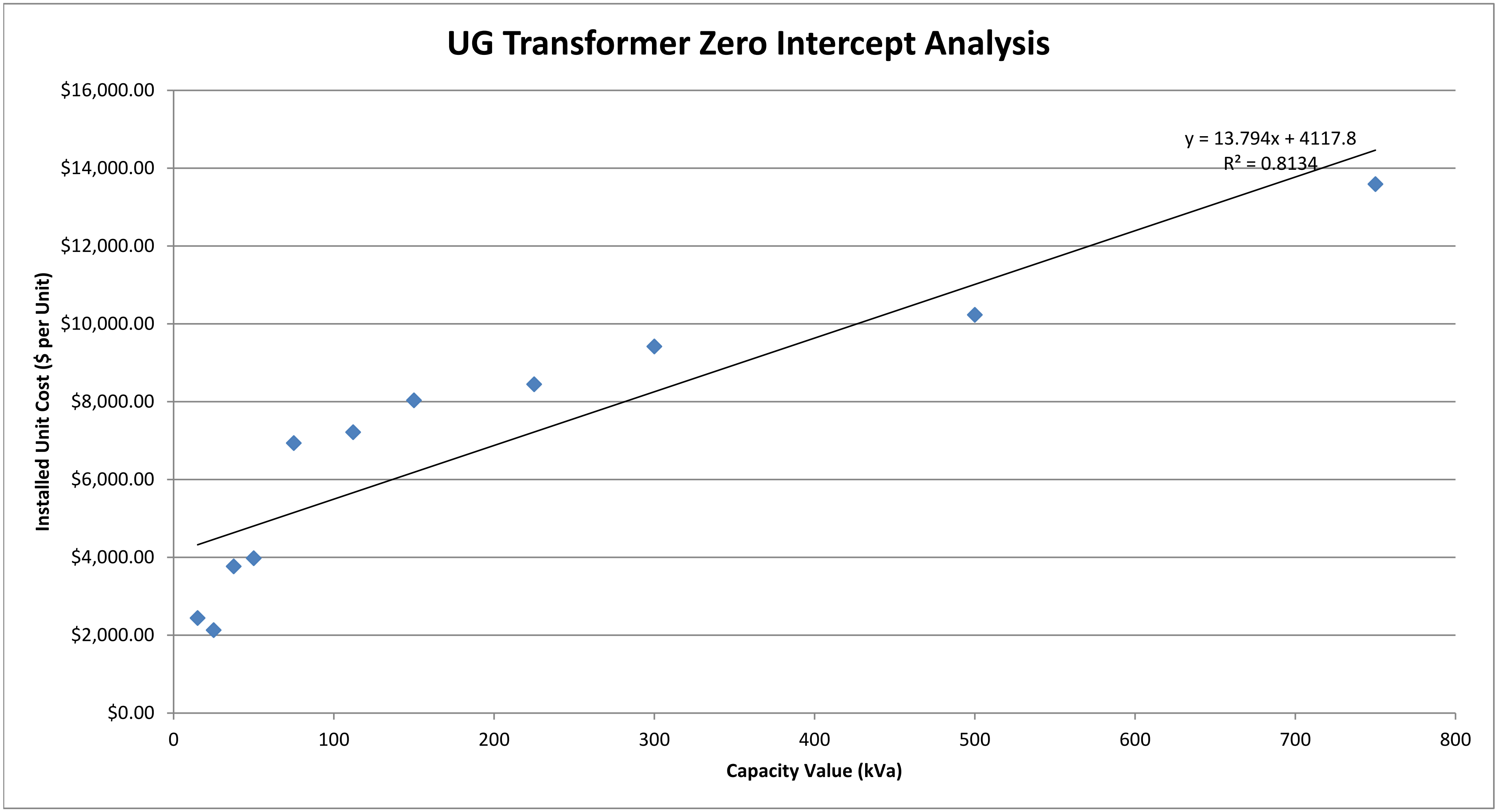

OH Secondary Zero Intercept Analysis
y = 0.0047x + 3.1315
R² = 0.529
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
Installed Unit Cost ($ per Ft)
0
50
100
150
200
250
300
350
Capacity Value (Amps)


OH Transformer Zero Intercept Analysis
y = 28.226x + 2139.7
R² = 0.8954
AxUnit Cosr ($ per Unit)
$7,000.00
$6,000.00
$5,000.00
$4,000.00
$3,000.00
$2,000.00
$1,000.00
$0.00
0
20
40
60
80
100
120
140
160
Capacity Value kVa


UG Primary Zero Intercept Analysis
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$0.00
Installed Unit Cost ($ per Ft)
y = 0.0178x + 9.6302
R² = 0.7997
0
500
1000
1500
2000
2500
Capacity Value (Amps)

Northern States Power Company
Underground Secondary Zero Intercept Analysis




UG Transformer Zero Intercept Analysis
$16,000.00
$14,000.00
$12,000.00
$10,000.00
$8,000.00
$6,000.00
$4,000.00
$2,000.00
$0.00
Installed Unit Cost ($ per Unit)
y = 13.794x + 4117.8
R² = 0.8134
0
100
200
300
400
500
600
700
800
Capacity Value (kVa)

Northern States Poser Company

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Exhibit___(MAP-1), Schedule 10
Attachment N

Minimum System / Zero Intercept Distribution System Cost Analysis

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9] = [4] x [8]	[10]	[11] = [4] x [10]	[12]	[13] = [4] x [12]
Line	**Property Unit**	**Phase**	**Config Details**	**Conductor Footage/Number Transformers**	**% of Total Population Footage/ Transformers**	**Cumulative % of Total Population Footage/ Transformers**	**Load Carrying Capacity (A, or kVA)**	**Installed Unit Cost**	**Total Cost**	**Y Intercept Minimum Cost per Unit**	**Total Cost Using Y Intercept Unit Cost**	**Minimum System Cost per Unit**	**Total Cost Using Minimum System Cost per Unit**
1	OH Primary	1 ph	4 ACSR 1ph	10,779,829	15.3%	15.3%	150	$15.68	$169,056,584	$6.92	$74,596,418	$12.49	$134,647,411
2	OH Primary	1 ph	2 ACSR 1ph	9,980,490	14.1%	29.4%	200	$12.49	$124,663,116	$6.92	$69,064,988	$12.49	$124,663,116
3	OH Primary	1 ph	6A CUWD 1ph	7,738,000	11.0%	40.4%	140	$7.45	$57,634,222	$6.92	$53,546,957	$12.49	$96,652,887
4	OH Primary	1 ph	6 CU 1ph	7,002,819	9.9%	50.3%	140	$7.45	$52,171,003	$6.92	$48,459,509	$12.49	$87,469,983
5	OH Primary	1 ph	3/10 CU 1ph	1,602,784	2.3%	52.5%	165	$6.28	$10,072,983	$6.92	$11,091,269	$12.49	$20,019,870
6		**Total 1 Phase Primary in Sample**		37,103,922				**$11.15**	$413,597,907		$256,759,141		$463,453,267
7	OH Primary	3 ph	336 AL 3ph	6,544,945	9.3%	61.8%	1680	$43.13	$282,304,381	$6.92	$45,291,021	$12.49	$81,750,826
8	OH Primary	3 ph	2 ACSR 3ph	5,900,093	8.4%	70.2%	600	$20.63	$121,747,785	$6.92	$40,828,642	$12.49	$73,696,179
9	OH Primary	3 ph	336 ACSR 3ph	4,863,151	6.9%	77.1%	1695	$49.41	$240,279,084	$6.92	$33,653,007	$12.49	$60,744,073
10	OH Primary	3 ph	2/0 ACSR 3ph	2,366,505	3.4%	80.4%	885	$21.57	$51,053,227	$6.92	$16,376,214	$12.49	$29,559,260
11	OH Primary	3 ph	4 ACSR 3ph	1,862,263	2.6%	83.0%	450	$21.17	$39,424,099	$6.92	$12,886,857	$12.49	$23,260,929
12	OH Primary	3 ph	6 CU 3ph	1,325,050	1.9%	84.9%	420	$10.06	$13,330,000	$6.92	$9,169,344	$12.49	$16,550,774
13	OH Primary	3 ph	6A CUWD 3ph	774,047	1.1%	86.0%	420	$10.06	$7,785,340	$6.92	$5,356,406	$12.49	$9,668,376
14	OH Primary	3 ph	1/0 ACSR 3ph	803,837	1.1%	87.2%	780	$18.44	$14,825,621	$6.92	$5,562,551	$12.49	$10,040,470
15	OH Primary	3 ph	4/0 CU 3ph	817,258	1.2%	88.3%	1680	$24.41	$19,945,516	$6.92	$5,655,426	$12.49	$10,208,111
16	OH Primary	3 ph	556 AL 3ph	444,492	0.6%	88.9%	2295	$43.77	$19,457,033	$6.92	$3,075,883	$12.49	$5,552,005
17	OH Primary	3 ph	556 ACSR 3ph	343,150	0.5%	89.4%	2295	$44.06	$15,118,255	$6.92	$2,374,595	$12.49	$4,286,171
18	OH Primary	3 ph	336 AAC 3ph	284,217	0.4%	89.8%	1680	$45.14					
19	OH Primary	3 ph	556 AAC 3ph	200,338	0.3%	90.1%	2295	$51.19					
20	OH Primary	**Total 3 Phase Primary in Sample**		26,529,345				**$31.11**	$825,270,341		$180,229,947		$325,317,174
19	OH Primary	**Total 1 Ph & 3 Ph OH Primary in Sample**		63,633,268				**$19.47**	$1,238,868,249		$436,989,088		$788,770,441
20										**% Customer Related Costs Using Zero Intercept =**	**35.27%**	**% Customer Related Costs Using Minimum System =**	**63.67%**

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9] = [4] x [8]	[10]	[11] = [4] x [10]	[12]	[13] = [4] x [12]
Line	**Property Unit**	**Phase**	**Config Details**	**Conductor Footage/Number Transformers**	**% of Total Population Footage/ Transformers**	**Cumulative % of Total Population Footage/ Transformers**	**Load Carrying Capacity (A, or kVA)**	**Installed Unit Cost**	**Total Cost**	**Y Intercept Minimum Cost per Unit**	**Total Cost Using Y Intercept Unit Cost**	**Minimum System Cost per Unit**	**Total Cost Using Minimum System Cost per Unit**
21	OH Secondary		2 ACSR Open Wire	20,659,710	15.1%	15.1%	200	$4.26	$88,059,428	$3.13	$64,664,893	$3.95	$81,590,435
22	OH Secondary		4 ACSR Open Wire	9,593,567	7.0%	22.1%	150	$3.61	$34,654,866	$3.13	$30,027,866	$3.95	$37,887,431
23	OH Secondary		1/0 ACSR Open Wire	18,464,472	13.5%	35.6%	260	$4.34	$80,052,652	$3.13	$57,793,798	$3.95	$72,920,884
24	OH Secondary		6 CU Open Wire	10,042,139	7.3%	43.0%	140	$4.12	$41,399,445	$3.13	$31,431,894	$3.95	$39,658,952
25	OH Secondary		6A CUWD Open Wire	6,529,682	4.8%	47.7%	140	$3.79	$24,729,601	$3.13	$20,437,903	$3.95	$25,787,369
26	OH Secondary		4 CU Open Wire	15,421,282	11.3%	59.0%	185	$3.43	$52,841,488	$3.13	$48,268,613	$3.95	$60,902,554
27	OH Secondary		2 CU Open Wire	15,133,733	11.1%	70.1%	245	$3.72	$56,266,499	$3.13	$47,368,586	$3.95	$59,766,952
28	OH Secondary		1/0 AL Triplex	7,529,615	5.5%	75.6%	205	$3.95	$29,736,358	$3.13	$23,567,694	$3.95	$29,736,358
29	OH Secondary		6 ACSR Duplex	4,816,255	3.5%	79.1%	90	$3.65	$17,566,983	$3.13	$15,074,878	$3.95	$19,020,612
30	OH Secondary		1/0 AL Triplex, Lashed	6,462,163	4.7%	83.8%	205	$4.44	$28,667,046	$3.13	$20,226,571	$3.95	$25,520,721
31	OH Secondary		3/10 CU Open Wire	1,561,406	1.1%	85.0%	165	$3.81	$5,954,036	$3.13	$4,887,200	$3.95	$6,166,387
32	OH Secondary		1/0 CU Open Wire	2,553,956	1.9%	86.8%	300	$4.90	$12,520,647	$3.13	$7,993,883	$3.95	$10,086,221
33	OH Secondary		2 AL Triplex	2,563,679	1.9%	88.7%	150	$3.85	$9,866,366	$3.13	$8,024,316	$3.95	$10,124,619
34	OH Secondary		2/0 ACSR Open Wire	794,643	0.6%	89.3%	295	$4.86	$3,861,966	$3.13	$2,487,233	$3.95	$3,138,247
35	OH Secondary		6 AL Duplex	1,363,325	1.0%	90.3%	90	$3.77	$5,145,197	$3.13	$4,267,207	$3.95	$5,384,116
36	OH Secondary		1/0 AL Open Wire	1,266,940	0.9%	91.2%	265	$4.23	$5,357,966	$3.13	$3,965,521	$3.95	$5,003,466
37		**Total OH Secondary in Sample**		124,756,567				**$3.98**	$496,680,543		$390,488,056		$492,695,327
38										**% Customer Related Costs Using Zero Intercept =**	**78.62%**	**% Customer Related Costs Using Minimum System =**	**99.20%**

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9] = [4] x [8]	[10]	[11] = [4] x [10]	[12]	[13] = [4] x [12]
Line	**Property Unit**	**Phase**	**Config Details**	**Conductor Footage/Number Transformers**	**% of Total Population Footage/ Transformers**	**Cumulative % of Total Population Footage/ Transformers**	**Load Carrying Capacity (A, or kVA)**	**Installed Unit Cost**	**Total Cost**	**Y Intercept Minimum Cost per Unit**	**Total Cost Using Y Intercept Unit Cost**	**Minimum System Cost per Unit**	**Total Cost Using Minimum System Cost per Unit**
39	OH Transformers		1 Phase Wye 25 kVA	33,645	29.4%	29.4%	25	$2,737	$92,087,348	$2,140	$72,000,300	$2,253	$75,802,185
40	OH Transformers		1 Phase Wye 10 kVA	18,868	16.5%	45.8%	10	$2,253	$42,503,217	$2,140	$40,377,520	$2,253	$42,509,604
41	OH Transformers		1 Phase Wye 37.5 kVA	16,272	14.2%	60.0%	37.5	$3,851	$62,671,592	$2,140	$34,822,080	$2,253	$36,660,816
42	OH Transformers		1 Phase Wye 15 kVA	17,020	14.9%	74.9%	15	$2,052	$34,930,407	$2,140	$36,422,800	$2,253	$38,346,060
43	OH Transformers		1 Phase Wye 50 kVA	13,415	11.7%	86.6%	50	$3,617	$48,518,100	$2,140	$28,708,100	$2,253	$30,223,995
44	OH Transformers		3 Phase Wye/Wye 75 kVA	1,300	1.1%	87.7%	75	$3,645	$4,738,163	$2,140	$2,782,000	$2,253	$2,928,900
45	OH Transformers		3 Phase Wye/Wye 150 kVA	1,034	0.9%	88.6%	150	$6,155	$6,364,154	$2,140	$2,212,760	$2,253	$2,329,602
46	OH Transformers		3 Phase Wye/Wye 112 kVA	594	0.5%	89.2%	112	$5,789	$3,438,656	$2,140	$1,271,160	$2,253	$1,338,282
47	OH Transformers		3 Phase Wye/Wye 45 kVA	767	0.7%	89.8%	45	$4,008	$3,073,902	$2,140	$1,641,380	$2,253	$1,728,051
48	OH Transformers		1 Phase Wye 100 kVA	607	0.5%	90.4%	100	$4,776	$2,899,329	$2,140	$1,298,980	$2,253	$1,367,571
49			**Total OH Transformers in Sample**	103,522				**$2,909.77**	**$301,224,867**		**$221,537,080**		**$233,235,066**
50										**% Customer Related Costs Using Zero Intercept =**	**73.55%**	**% Customer Related Costs Using Minimum System =**	**77.43%**
51	UG Primary	1 ph	1/0 AL 1ph	16,001,972	29.0%	29.0%	275	$14.98	$239,683,496	$9.63	$154,098,992	$11.32	$181,080,066
52	UG Primary	1 ph	2 AL 1ph	14,328,983	25.9%	54.9%	225	$11.32	$162,148,341	$9.63	$137,988,109	$11.32	$162,148,341
53			**Total 1 Phase Primary in Sample**	30,330,955				**$13.25**	**$401,831,837**		**$292,087,100**		**$343,228,408**
54													
55	UG Primary	3 ph	1/0 AL 3ph	13,798,626	25.0%	79.9%	645	$19.40	$267,672,674	$9.63	$132,880,769	$11.32	$156,146,761
56	UG Primary	3 ph	750 AL 3ph	4,716,848	8.5%	88.5%	1890	$35.25	$166,287,861	$9.63	$45,423,243	$11.32	$53,376,364
57	UG Primary	3 ph	2 AL 3ph	1,079,318	2.0%	90.4%	510	$20.62	$22,255,542	$9.63	$10,393,834	$11.32	$12,213,683
58	UG Primary	3 ph	1000 AL 3ph	541,370	1.0%	91.4%	2190	$39.34	$21,295,087	$9.63	$5,213,389	$11.32	$6,126,197
59	UG Primary	3 ph	500 AL 3ph	465,879	0.8%	92.2%	1545	$36.51	$17,009,235	$9.63	$4,486,413	$11.32	$5,271,936
60	UG Primary	3 ph	500 CU 3ph	745,916	1.4%	93.6%	1830	$59.31	$44,239,878	$9.63	$7,183,168	$11.32	$8,440,863
61	UG Primary	3 ph	750 CU 3ph	416,228	0.8%	94.3%	2340	$53.50	$22,269,593	$9.63	$4,008,273	$11.32	$4,710,078
62			**Total 3 Phase Primary in Sample**	21,298,305				**$25.54**	**$544,020,635**		**$209,589,088**		**$246,285,881**
63													
64			**Total 1 Ph & 3 Ph UG Primary in Sample**	51,629,260					**$945,852,472**		**$501,676,188**		**$589,514,289**
65										**% Customer Related Costs Using Zero Intercept =**	**53.04%**	**% Customer Related Costs Using Minimum System =**	**62.33%**

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9] = [4] x [8]	[10]	[11] = [4] x [10]	[12]	[13] = [4] x [12]
Line	**Property Unit**	**Phase**	**Config Details**	**Conductor Footage/Number Transformers**	**% of Total Population Footage/ Transformers**	**Cumulative % of Total Population Footage/ Transformers**	**Load Carrying Capacity (A, or kVA)**	**Installed Unit Cost**	**Total Cost**	**Y Intercept Minimum Cost per Unit**	**Total Cost Using Y Intercept Unit Cost**	**Minimum System Cost per Unit**	**Total Cost Using Minimum System Cost per Unit**
66	UG Secondary		6 AL Duplex	10,661,412	38.0%	38.0%	90	$7.55	$80,507,317	$6.00	$63,968,471	$11.63	$123,971,012
67	UG Secondary		4/0 AL Triplex	8,422,109	30.0%	68.0%	340	$12.97	$109,209,956	$6.00	$50,532,652	$11.63	$97,932,371
68	UG Secondary		2/0 AL Triplex	2,703,807	9.6%	77.6%	280	$10.72	$28,993,248	$6.00	$16,222,844	$11.63	$31,439,901
69	UG Secondary		1/0 AL Triplex	1,572,271	5.6%	83.2%	220	$11.63	$18,282,381	$6.00	$9,433,624	$11.63	$18,282,381
70	UG Secondary		6 CU Open Wire	1,230,243	4.4%	87.6%	140	$7.18	$8,837,212	$6.00	$7,381,458	$11.63	$14,305,278
71	UG Secondary		350 AL Triplex	574,237	2.0%	89.7%	450	$13.20	$7,580,359	$6.00	$3,445,419	$11.63	$6,677,229
72		**Total UG Secondary in Sample**		25,164,078				**$10.07**	**$253,410,473**		**$150,984,467**		**$292,608,172**
73										**% Customer Related Costs Using Zero Intercept =**	**59.58%**	**% Customer Related Costs Using Minimum System =**	**100.00%**
74	UG Transformers		1 Phase Wye 50 kVA	27,634	32.3%	32.3%	50	$3,977	$109,901,575	$4,118	$113,796,812	$2,440	$67,437,807
75	UG Transformers		1 Phase Wye 25 kVA	18,283	21.4%	53.7%	25	$2,129	$38,929,413	$4,118	$75,289,394	$2,440	$44,617,696
76	UG Transformers		1 Phase Wye 37.5 kVA	9,017	10.5%	64.2%	37.5	$3,770	$33,989,685	$4,118	$37,132,006	$2,440	$22,005,019
77	UG Transformers		3 Phase Wye/Wye 150 kVA	3,764	4.4%	68.6%	150	$8,036	$30,248,403	$4,118	$15,500,152	$2,440	$9,185,637
78	UG Transformers		3 Phase Wye/Wye 300 kVA	3,671	4.3%	72.9%	300	$9,417	$34,568,758	$4,118	$15,117,178	$2,440	$8,958,681
79	UG Transformers		3 Phase Wye/Wye 75 kVA	3,535	4.1%	77.1%	75	$6,936	$24,516,999	$4,118	$14,557,130	$2,440	$8,626,788
80	UG Transformers		3 Phase Wye/Wye 500 kVA	3,161	3.7%	80.8%	500	$10,233	$32,345,801	$4,118	$13,016,998	$2,440	$7,714,081
81	UG Transformers		1 Phase Wye 15 kVA	2,399	2.8%	83.6%	15	$2,440	$5,854,502	$4,118	$9,879,082	$2,440	$5,854,502
82	UG Transformers		3 Phase Wye/Wye 112 kVA	2,030	2.4%	85.9%	112	$7,217	$14,649,674	$4,118	$8,359,540	$2,440	$4,953,997
83	UG Transformers		3 Phase Wye/Wye 225 kVA	1,829	2.1%	88.1%	225	$8,446	$15,448,447	$4,118	$7,531,822	$2,440	$4,463,478
84	UG Transformers		3 Phase Wye/Wye 750 kVA	1,812	2.1%	90.2%	750	$13,586	$24,618,211	$4,118	$7,461,816	$2,440	$4,421,991
85		**Total UG Transformers in Sample**		77,135				**$4,732.89**	**$365,071,467**		**$317,641,930**		**$188,239,676**
86													
										% Customer Related Costs Using Zero Intercept =	**87.01%**	**% Customer Related Costs Using Minimum System =**	**51.56%**
87		**Total OH and UG Transforners in Sample**		180,657				**$3,688**	**$666,296,334**		**$539,179,010**		**$421,474,742**
88										**% Customer Related Costs Using Zero Intercept =**	**80.92%**	**% Customer Related Costs Using Minimum System =**	**63.26%**

		[1]	[2]	[3] = [1] x [2]	[4] = % of Line 11	[5] = [Col 5 Line 11 - Line 10] x [4]	[6] = (Customer % from Attachment N)	[7]	[8]
Line	**Overhead Distribution Plant**	**Total Footage**	**Average Cost per Foot**	**Total Replacement Cost ($000)**	**% of Total Replacement Cost**	**Test Year Plant in Service ($000)**	**% Customer or Capacity Related**	**Final Test Year Plant in Service ($000)**	**% of Total Overhead Dist Costs**
1	OH Primary Single Phase Capacity						64.73%	$153,065	14.43%
2	OH Primary Single Phase Customer						35.27%	$83,414	7.87%
3	Total OH Primary Single Phase	40,629,520	$11.15	$452,898	23.46%	$236,478	100.00%	$236,478	
4	OH Primary Multi Phase Capacity						64.73%	$315,250	29.73%
5	OH Primary Multi Phase Customer						35.27%	$171,797	16.20%
6	Total OH Primary Multi Phase	29,985,424	$31.11	$932,781	48.33%	$487,047	100.00%	$487,047	
7	OH Secondary Capacity						21.38%	$60,789	5.73%
8	OH Secondary Customer						78.62%	$223,533	21.08%
9	Total OH Secondary	136,774,689	$3.98	$544,527	28.21%	$284,322	100.00%	$284,322	
10	Street Lighting (see Line 9 of Schedule XX)					$52,663		$52,663	4.97%
11	Total Overhead (see Schedule X, Page 4, Column 1, Line XX)			$1,930,206	100.00%	$1,060,509		$1,060,509	100.00%

		[1]	[2]	[3] = [1] x [2]	[4] = % of Line 22	[5] = [Col 5 Line 22 - Line 21] x [4]	[6] = (Customer % from Attachment N)	[7]	[8]
	Underground Distribution Plant	**Total Footage**	**Average Cost per Foot**	**Total Replacement Cost ($000)**	**% of Total Replacement Cost**	**Test Year Plant in Service ($000)**	**% Customer or Capacity Related**	**Final Test Year Plant in Service ($000)**	**% of Total Underground Distr Costs**
12	UG Primary Single Phase Capacity						37.67%	$187,315	11.81%
13	UG Primary Single Phase Customer						62.33%	$309,888	19.55%
14	Total UG Primary Single Phase	31,045,217	$13.25	$411,295	31.36%	$497,203	100.00%	$497,203	
15	UG Primary Multi Phase Capacity						37.67%	$281,253	17.74%
16	UG Primary Multi Phase Customer						62.33%	$465,295	29.35%
17	Total UG Primary Multi Phase	24,177,202	$25.54	$617,556	47.09%	$746,548	100.00%	$746,548	
18	UG Secondary Capacity						40.42%	$138,113	8.71%
19	UG Secondary Customer						59.58%	$203,590	12.84%
20	Total UG Secondary	28,068,796	$10.07	$282,662	21.55%	$341,703	100.00%	$341,703	
21	Street Lighting					$0		$0	0.00%
22	Total Underground			$1,311,513		$1,585,454		$1,585,454	100.00%

		[1]	[2]	[3] = [1] x [2]	[4] = % of Line 27	[5] = [Col 5 Line 27] x [4]	[6] = (Customer % from Attachment N)	[7]	[8]
	Transformers	**Number of Transformers**	**Average Cost Per Transformer**	**Total Replacement Cost ($000)**	**% of Total Replacement Cost**	**Test Year Plant in Service ($000)**	**% Customer or Capacity Related**	**Final Test Year Plant in Service ($000)**	**% of Total Transformer Costs**
23	Primary	1,471	$58,201	$85,614	16.85%	$51,498	100% Capacity	$51,498	16.85%
24	Secondary Capacity						35.84%	$91,091	29.80%
25	Secondary Customer						64.16%	$163,064	53.35%
26	Total Secondary	114,562	$3,688	$422,526	83.15%	$254,155	100.00%	$254,155	83.15%
27	Total Transformers			$508,140		$305,653		$305,653	100.00%

	[1]	[2]	[3]	[4]	[5]	[6] = [3] x [4] x [5] / 1000	[7]	[8] = [6] / [7]	[9] = 1 - [8]
	Services	**Minimum Conductor Configuration**	**Minimum Footage per Service**	**Installed Cost per Foot**	**Number of Customers**	**Total Minimum Installed Cost ($000)**	**Test Year Plant Investment Distribution Services ($000)**	**Customer Component Distribution Services**	**Capacity Component Distribution Services**
1	OH Services	2 ACSR Triplex	50	$4.03	808,967	$163,007			
2	UG Services	1/0 Triplex	50	$2.81	454,000	$63,787			
3	Total Services				1,262,967	$226,794	$364,895	62.15%	37.85%

Northern States Power Company

Test Year Ending December 31, 2022
Primary Distribution Cost Allocator Calculations

					Customer Class				
Line	**Primary Distribution Cost**	**Allocator Derivation**	**Allocator Label**	**MN**	**Resid**	**Commercial Non Demand**	**C&I Demand Secondary**	**C&I Demand Primary**	**Ltg**
1	Customer Portion of **Multi-Phase** Primary Lines	Number of Customers	C61PS	1,341,763	1,197,510	88,539	49,521	485	5,708
2	Capacity Portion of **Multi-Phase** Primary Lines	Class Coincident Peak Demands	D61PS	5,609,175	2,070,452	142,337	2,720,832	657,005	18,548
3	% of Customers Served by Primary **Single Phase** Lines				**72.7%**	**41.0%**	**12.3%**	**15.6%**	**53.6%**
4	Customer Portion of **Single-Phase** Primary Lines	line 1 x line 3	C61PS1Ph	916,386	870,809	36,340	6,100	76	3,061
5	Capacity Portion of Single-Phase Primary Lines	line 2 x line 3	D61PS1Ph	2,011,456	1,505,599	58,421	335,171	102,321	9,945
6	Customer Portion of **Multi-Phase** Primary Lines	Cost Allocator %	C61PS	100.0%	89.2%	6.6%	3.7%	0.0%	0.4%
7	Capacity Portion of **Multi-Phase** Primary Lines	Cost Allocator %	D61PS	100.0%	36.9%	2.5%	48.5%	11.7%	0.3%
8	Customer Portion of **Single-Phase** Primary Lines	Cost Allocator %	C61PS1Ph	100.0%	95.0%	4.0%	0.7%	0.0%	0.3%
9	Capacity Portion of **Single-Phase** Primary Lines	Cost Allocator %	D61PS1Ph	100.0%	74.9%	2.9%	16.7%	5.1%	0.5%

	2022	2023	2024	2025	2026
Renewable*Connect Month-to-Month	$1,340,911	$1,340,911	$1,340,911	$1,340,911	$1,340,911
Renewable*Connect Pilot	$1,298,374	$1,328,121	$1,361,368	$1,392,865	$1,426,111
Renewable*Connect Standard	$985,057	$1,008,355	$1,031,637	$1,054,613	$1,079,887
Renewable*Connect High Off-Peak	$1,364,194	$1,395,989	$1,428,149	$1,460,886	$1,493,623
Total Capacity Credit	$4,988,536	$5,073,375	$5,162,065	$5,249,275	$5,340,533

Renewable*Connect Month-to-Month Capacity Credit

		2022	2023	2024	2025	2026
[1]	Renewable*Connect Month-to-Month Sales (kWh)	478,896,835	478,896,835	478,896,835	478,896,835	478,896,835
[2]	Capacity Credit $ per kWh	$0.00280	$0.00280	$0.00280	$0.00280	$0.00280
[5]	**Total Renewable*Connect Capacity Credit (Line 1 * Line 2)**	**$1,340,911**	**$1,340,911**	**$1,340,911**	**$1,340,911**	**$1,340,911**

Renewable*Connect Pilot Capacity Credit

		2022	2023	2024	2025	2026
[1]	Renewable*Connect Pilot Sales (kWh)	164,583,000	164,583,000	164,583,000	164,583,000	164,583,000
[2]	Renewable*Connect Government Pilot Sales (kWh)	10,400,000	10,400,000	10,400,000	10,400,000	10,400,000
[3]	Total Renewable*Connect Pilot Sales (kWh) (Line 1 + Line 2)	174,983,000	174,983,000	174,983,000	174,983,000	174,983,000
[4]	Capacity Credit $ per kWh	0.00742	0.00759	0.00778	0.00796	0.00815
[5]	**Total Renewable*Connect Capacity Credit (Line 3 * Line 4)**	**$1,298,374**	**$1,328,121**	**$1,361,368**	**$1,392,865**	**$1,426,111**

		2022	2023	2024	2025	2026
[1]	Renewable*Connect - Standard Sales (kWh)	228,551,553	229,258,359	229,763,220	229,763,220	229,763,220
[2]	Capacity Credit $ per kWh	$0.00431	$0.00440	$0.00449	$0.00459	$0.00470
[3]	**Renewable*Connect Capacity Credit (Line 1 * Line 2)**	**$985,057**	**$1,008,355**	**$1,031,637**	**$1,054,613**	**$1,079,887**

Renewable*Connect - High Off-Peak Capacity Credit

		2022	2023	2024	2025	2026
[1]	Renewable*Connect - High Off-Peak Sales (kWh)	407,222,181	408,382,815	409,211,840	409,211,840	409,211,840
[2]	Capacity Credit $ per kWh	$0.00335	$0.00342	$0.00349	$0.00357	$0.00365
[3]	**Total Renewable*Connect Capacity Credit (Line 1 * Line 2)**	**$1,364,194**	**$1,395,989**	**$1,428,149**	**$1,460,886**	**$1,493,623**

CIP Program Rider--Conservation Cost Recovery Charge (CCRC) and Conservation Adjustment Factor (CAF) Calculations

TY22 -2022 Approved CIP Budget[1]	
Business	$ 55,467,796
Residential	$ 29,667,583
Low-Income	$ 2,943,296
Planning	$ 11,912,594
Research, Evaluations, & Pilots	$ 6,516,523
Regulatory Assessments	$ 1,974,981
EUI	$ 0
Alternative Filings	$ 20,002,690
2022 Approved CIP Budget	**$ 128,485,463**
TY22 kWh	
TY 2022 MN kWh Sales	27,377,491,263
TY 2022 CIP Exempt Cust Sales (Est.)	1,200,196,568
Net CIP Sales	26,177,294,695

CCRC = TY22 CIP Expense / TY2022 kWh Sales **0.4908** **¢ per kWh**

	Current	TY 2022	Difference
CCRC (cents/kWh)	**0.3133** [2]	**0.4908** [3]	0.1775
CIP Adjustment Factor (cents/kWh)	**0.3521** [4]	**0.1746** [5]	-0.1775
Total (cents/kWh)	0.6654	0.6654	0

[1] The 2022 CIP Budget was approved in the Deputy Commissioner's Decision of November 25, 2020. Budget changes in subsequent compliance filings and program modifications are not included.

[2] The 0.3133 cents/kWh CCRC approved by MPUC on June 12, 2017 in Docket No. E002/GR-15-826.

[3] The 0.4908 cents/kWh CCRC for TY 2022 determined above.

[4] The 0.3521 cents/kWh CIP Adjustment Factor for 2021/2022 was approved by MPUC on September 7, 2021 in Docket No. E002/M-21-226 and updated in a September 17, 2021 Compliance Filing.

[5] The 0.1746 cents/kWh CIP Adjust Factor for TY 2022 determined as shown above: (0.3521 CIP Adjust minus 0.1775 Difference in CCRC).

Excess Footage and Winter Construction Revenue Impact

Tariff	Description	Present Price	Proposed Price	2020 Units	Present $	Proposed $	Difference
5.1	**Standard Installation and Extension Rules**						
	Excess service charge - Services	$7.90	$12.50	39,979	$315,834	$499,738	$183,903
	Excess service charge - Excess single phase primary	$8.00	$13.00	-	$0	$0	$0
	Excess service charge - Excess three phase primary	$13.90	$21.00	-	$0	$0	$0
5.1.A.2.	**Winter Construction**						
	Per Thaw Unit	$600.00	$685.00	984	$590,400	$674,040	$83,640
	Per Trench Foot	$3.80	$8.90	122,398	$465,112	$1,089,342	$624,230
			REVENUE IMPACT		**$1,371,347**	**$2,263,120**	**$891,773.20**

Section 6.5.1.A1.	
Excess Footage Charge	**Current Electric tariff per circuit foot**
Services	$7.90
Excess single phase primary or secondary extension	$8.00
Excess three phase primary or secondary extension	$13.90

Task	SAP	Overhead	Total Costs
Services	$ 8.81	42.78%	$12.58
Excess single phase primary or secondary extension	$ 9.27	42.78%	$13.24
Excess three phase primary or secondary extension	$ 14.57	42.78%	$20.80

TARIFF	Current Electric tariff per circuit foot	Proposed Tariff Charge per circuit foot
Services	$7.90	**$12.50**
Excess single phase primary or secondary extension	$8.00	**$13.00**
Excess three phase primary or secondary extension	$13.90	**$21.00**

Equipment Specifications

Assumptions - based off 100 ft service
Single Phase secondary = 4/0 alum tri w/ installation
Single Phase primary = #2 alum 1/0 primary w/ installation
3 Phase primary or secondary = 1/0 alum 3/0 primary w/ installation
Engineering and Supervision Overhead: average rate 42.78%

2020 Winter Construction Thaw Unit Costs

Before January 1st (typically burns for 2 days)
A thaw unit requires 3 - 20 lb propane tanks to run for 2 days (20 lb tank = 5 gallons)

Process	Crew or Vehicles	Time to Do	Cost per Hour	Cost	Cost per Gallon	Gallons Used	Propane Cost	Totals
Set thaw unit	Two man crew	1	$93.59	$93.59				
Re-tank thaw unit	Two man crew	0	$93.59	$0.00				
Remove thaw unit	Two man crew	0.5	$93.59	$46.80				
Total Labor				$140.39				
Labor Loading @ 76.87%				$107.91				
Labor w/ Loading				$248.30				$248.30
Vehicle & Equipment	truck and trailer	1.5	13.11	$19.67				$19.67
Propane Cost					2.02	15	$30.30	$30.30
Costs (before E&S)				$298.26				$298.26
E&S Cost @ 42.78%				$127.60				$127.60
Total Cost				$425.86				$425.86

After January 1st (typically burns for 3 days)

Process	Crew or Vehicles	Time to Do	Cost per Hour	Cost	Cost per Gallon	Gallons Used	Propane Cost	Totals
Set thaw unit	Two man crew	1	$93.59	$93.59				
Re-tank thaw unit	Two man crew	1	$93.59	$93.59				
Remove thaw unit	Two man crew	0.5	$93.59	$46.80				
Total Labor				$233.98				
Labor Loading @ 76.87%				$179.86				
Labor w/ Loading				$413.83				$413.83
Vehicle & Equipment	truck and trailer	2.5	13.11	$32.78				$32.78
					2.02	22.5	$45.45	$45.45
Propane Cost								
Costs (before E&S)				$492.06				$492.06
E&S Cost @ 42.78%				$210.50				$210.50
Total Cost				$702.56				$702.56

* Please note, 90% of all thaw units are set after January 1st.

Before and after January Costs	Percentage	
$425.86	10%	$42.59
$702.56	90%	$632.30
		$674.89
Billing Labor		$10.00
Producing Bill		$0.11
Postage		$0.40
Total Cost of a Thaw Unit		**$685.39**

2020 Winter Construction Per foot Charge

Winter Construction billed for in Winter of 2019

Average Cost per Foot Winter 2019 Services =	$28.07
Average Cost per Foot Non-Winter Months Services =	$19.16
Difference for Winter Construction	**$8.91**

2020 Updates to Charges

Tariff							
Current Electric Charges			Updated Costs		Proposed Tarif Charge		
Service Extension	$600.00	per thaw unit	$685.39	per thaw unit	Thawing	$685.00	per thaw unit
	$3.80	plus per trench foot	$8.91	plus per trench foot	Secondary distribution extension	$8.90	per foot

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		kWh Sales					Incremental Energy Costs ($ per kWh)				
		Summer		Winter			Summer		Winter		
		1	2	3	4	5 = 1 + 2 + 3 + 4	6	7	8	9	10
Year	Peak Load (kW)	On Peak	Off Peak	On Peak	Off Peak	Total kWh Usage	On Peak	Off Peak	On Peak	Off Peak	Total Incremental Energy Costs
	[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS										
1											
2											
3											
4											
5											

HIGHLY CONFIDENTIAL TRADE SECRET ENDS]

	11	12	13	14	15	16 = 10 + 12 + 13 + 14 + 15	17	18	19	20	21	22 = 21 - 16
Year	Peak Load (kW)	Total Incremental Capacity Costs	Juris. Cost Allocation Increase to MN	MISO Costs	Total Incremental Transmission Costs	Total Incremental Costs	Rate Forecast ($ per kWh)	Revenues Before Discount	Rate Forecast under Discount ($ per kWh)	Total Discount	Revenues Remaining After Discount	Contribution to Margin
	[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS											
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Northern States Power Company
CRR - Incremental Cost Analysis

		kWh Sales					Incremental Energy Costs ($ per kWh)				
		Summer		Winter			Summer		Winter		
		1	2	3	4	5 = 1 + 2 +3 +4	6	7	8	9	10
Year	Peak Load (kW)	On Peak	Off Peak	On Peak	Off Peak	Total kWh Usage	On Peak	Off Peak	On Peak	Off Peak	Total Incremental Energy Costs
	[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS										
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