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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-20-723
Exhibit___(MAP-1)

Class Cost of Service Study and Selected Rate Design

November 2, 2020

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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 nearly 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 2021, 2022, and 2023 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:

- Section II discusses the compliance items related to the CCOSS and where these compliance items are addressed;

[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 III presents the Company's proposed 2021, 2022, and 2023 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;
- Provide a description of each allocation method and reasons why each method is appropriate;
- Provide data linkages in the CCOSS model and more data transparency in the model; and
- Provide 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.

[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) 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 IN THE 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. Steven V. Huso.

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

A. Yes. As discussed by Mr. Huso, 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 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

[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).

(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. 2021 CCOSS Results

Q. PLEASE SUMMARIZE THE RESULTS OF THE 2021 CCOSS.

A. Table 2 below provides a summary of the 2021 test year CCOSS (the 2021 CCOSS) results at the class level, showing the resulting class cost responsibilities (as opposed to revenue responsibilities that are addressed by Mr. Huso). Table 2 replicates Exhibit___(MAP-1), Schedule 3. However, for comparison purposes, Schedule 3 also provides the class revenue allocation proposed by Mr. Huso. The detailed 2021 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 2021 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)	3,648,234	1,400,135	108,228	1,927,750	32,111
[2]	Incr. Misc. Chrgs. & Late Pay (CCOSS page 7, line 21 to line 23)	1,468	1,277	46	144	1
[3]	Unadjusted Operating Revenues (line 1 + line 2)	3,469,702	1,401,412	108,274	1,927,903	32,113
[4]	Present Rates (CCOSS page 2, line 2)	3,063,950	1,217,322	103,012	1,716,271	27,346
[5]	Unadjusted Deficiency (line 3 - line 4)	405,752	184,090	5,262	211,632	4,767
[6]	Deficiency / Present Rates (line 5 / line 4)	13.2%	15.1%	5.1%	12.3%	17.4%
[7]	**Ratio: Class % / Total %**	**1.00**	**1.14**	**0.39**	**0.93**	**1.32**

COST RESPONSIBILITIES FOR RATE DISCOUNTS

		Total	Resid.	Non-Demand	Demand	Street Ltg
		[PROTECTED DATA 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)					
						PROTECTED DATA ENDS]
[12]	Revenue Requirement Change (lines 10 & 11 - lines 8 & 9)	0	(2,848)	835	2007	6

ADJUSTED COST RESPONSIBILITIES

		Total	Resid.	Non-Demand	Demand	Street Ltg.
[13]	Adjusted Rate Revenue Reqt (line 1 + line 12)	3,468,234	1,397,287	109,064	1,929,766	32,117
[14]	Incr. Misc. Chrgs. & Late Pay (CCOSS page 7, line 21 to line 23)	1,468	1,277	47	144	7
[15]	Adjusted Operating Revenues (line 13 + line 14)	3,469,702	1,398,564	109,110	1,929,910	32,1144
[16]	Present Rates (line 4)	3,063,950	1,217,322	103,012	1,716,271	27,345
[17]	Adjusted Deficiency (line 15 - line 16)	405,752	181,242	6,098	213,639	4,773
[18]	Deficiency / Present Rates (line 17 / line 16)	13.2%	14.9%	5.9%	12.4%	17.5%
[19]	**Ratio: Class % / Total %**	**1.00**	**1.12**	**0.45**	**0.94**	**1.322**

Q. IN TABLE 2, YOU SHOW "ADJUSTED" AND "UNADJUSTED" COST RESPONSIBILITIES. PLEASE SUMMARIZE 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 2021 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 2021 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. IN THE COMPANY'S LAST RATE CASE (DOCKET NO. E002/GR-15-826), THE STREET LIGHTING CLASS SHOWED A DEFICIENCY THAT WAS MUCH LARGER THAN HAD BEEN SEEN IN PRIOR RATE CASES, WHAT WAS THE REASON FOR THE LARGE INCREASE IN THE DEFICIENCY?

A. When the Company filed Direct Testimony its last rate case, the Street Lighting class had showed a deficiency of 17.5 percent compared to a deficiency of 1.8 percent with the compliance CCOSS in its prior rate case (Docket No. E002/GR-13-868). This was due to the fact that the compliance CCOSS did not take into account the results of the Company's 2012 Transmission, Distribution, and General Depreciation Study (Docket No. E,G002/D-12-858).[4]

[4] *In the Matter of Northern States Power Company's Five-Year Transmission, Distribution, and General Depreciation Study*, Docket No. E, G002/D-12-858, FIVE-YEAR TRANSMISSION, DISTRIBUTION, AND GENERAL DEPRECIATION STUDY(July 31, 2012).

This filing approved a redistribution of depreciation reserve between utility accounts within each functional class. This was done to equitably spread the depreciation reserve between all utility accounts in a functional class. While this redistribution did not change the total reserve within each functional class, it moved reserve from accounts within that functional class. The result of this redistribution for Electric Distribution Street Lighting was to transfer $23.4 million in depreciation reserve from Electric Distribution Street Lighting to other Electric Distribution accounts. This redistribution as approved by the Commission can be seen in Attachment H in the above referenced 2012 filing.

The result was a large increase in the return on rate base directly attributable to the lighting class. It should be noted that since the Company's 2013 rate case (Docket No. E002/GR-13-868), there has been no change to the cost allocation methods or methods used for directly assigning costs to the lighting class.

Q. DID THE RATE INCREASE APPROVED IN THE LAST RATE CASE (DOCKET NO. E002/GR-15-826) COMPENSATE FOR THIS LARGE DEFICIENCY?

A. No. Although the Company was not required to file a compliance CCOSS in the last rate case, the deficiency for the Street Lighting class remained at 11.3 percent after the ordered increase in Street Lighting rates. As a result, row 18 of Table 2 above shows that the deficiency for the Street Lighting class increased to 17.5 percent for the 2021 test year.

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.[5] The column labeled "FERC Accounts" specifies the FERC codes that are being allocated.[6] 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. 2022 and 2023 CCOSS Results

Q. IN ADDITION TO THE 2021 CCOSS, THE COMPANY HAS ALSO INCLUDED 2022 AND 2023 CCOSSS IN THIS FILING. COULD YOU EXPLAIN HOW THE 2021 CCOSS COMPARES TO THE 2022 AND 2023 CCOSSS?

A. The 2022 and 2023 CCOSSs use the same approach for allocators as the 2021 CCOSS, and they include increases in the revenue deficiency of $98.5 million and $93.1 million that reflect the respective 2022 and 2023 revenue requirement increases. Company witness Mr. Benjamin C. Halama discusses the 2022 and

[5] More detail on each allocator is provided in Appendices 2 and 3 of Schedule 2 (Guide to the Class Cost of Service Study).
[6] 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).

2023 plan year increases in his Direct Testimony. Tables 3 and 4 below provides a summary of the 2022 and 2023 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 2022 and 2023 CCOSS summaries and the class revenue allocations proposed by Mr. Huso. The detailed 2022 CCOSS output is included in Schedule 6. The detailed 2023 CCOSS output is included in Exhibit___(MAP-1), Schedule 8.

Table 3

Summary of 2022 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)	3,555,766	1,435,881	111,340	1,975,206	33,339
[21]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,655	1,435	52	177	1
[22]	Adjusted Operating Revenues (line 13 + line 14)	3,557,431	1,437,316	111,392	1,975,383	33,341
[23]	Present Rates (line 4)	3,053,147	1,197,981	103,959	1,723,881	27,326
[24]	Adjusted Deficiency (line 15 - line 16)	504,284	239,336	7,432	251,501	6,015
[25]	Deficiency / Present Rates (line 17 / line 16)	16.5%	20.0%	7.1%	14.6%	22.0%
[26]	**Ratio: Class % / Total %**	**1.00**	**1.21**	**0.43**	**0.88**	**1.33**

Table 4

Summary of 2023 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)	3,626,179	1,455,899	113,261	2,022,409	34,611
[28]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,854	1,588	58	206	2
[29]	Adjusted Operating Revenues (line 13 + line 14)	3,628,033	1,457,487	113,319	2,022,615	34,612
[30]	Present Rates (line 4)	3,303,677	1,184,879	103,902	1,714,543	27,353
[31]	Adjusted Deficiency (line 15 - line 16)	597,356	272,609	9,416	308,071	7,260
[32]	Deficiency / Pres Rates (line 17 / line 16)	19.7%	23.0%	9.1%	18.0%	26.5%
[33]	**Ratio: Class % / Total %**	**1.00**	**1.17**	**0.46**	**0.91**	**1.35**

Q. WHAT IS THE PURPOSE OF THE 2022 AND 2023 CCOSSS?

A. First, Mr. Huso uses the 2022 CCOSS to help design 2022 rates. Second, as mentioned above, we are required to provide a 2022 and 2023 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 2021 CCOSS, AND THE 2022 AND 2023 CCOSSS?

A. No. The relevant rate design question is whether the additional 2022 and 2023 plan year costs materially impact the relative inter-class cost responsibilities.

Tables 2, 3, and 4 above, show the 2022 and 2023 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 2021 CCOSS. Lines 20 through 26 of Table 3 and Lines 27 through 33 of Table 4 show the same data for the 2022 and 2023 CCOSSs. In particular, it is helpful to compare Line 19 for the 2021 CCOSS to the corresponding Line 26 for the 2021 CCOSS and Line 33 of the 2023 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 57 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	$942	$942 / $942	100.0%	0.0%
Nuclear	$4,952	$942 / $4,952	19.0%	81.0%
Fossil	$2,387	$942 / $2,387	39.5%	60.5%
Combined Cycle	$1,429	$942 / $1,429	65.9%	34.1%
Hydro	$5,557	$942 / $5,557	17.0%	83.0%
Wind	$14,024	$942/$14,024	6.7%	93.3%

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 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."

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 2021 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. 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 2021 test year.

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 upcoming June 2021-May 2022 planning year is 97.12 percent.

Q. WITHOUT A MISO PUBLISHED PEAK HOUR FOR THE 2021 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 11 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 11 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 (2013, 2014 and 2019) the MISO peak coincided with NSP's third, fourth, and sixth highest peak hours, respectively.

Table 7

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

For 2009 - 2019

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

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

A. Based on 11 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 2021 TEST YEAR, WHAT ARE THE FORECASTED SIX HIGHEST NSP SYSTEM PEAK HOURS?

A. The Company sorted the forecast 2021 NSP System 8,760 loads by load level and the six highest loads for the 2021 test year are shown in Table 8 below:

Table 8

Ranking of Highest NSP System Six Highest 2021 MW Load Levels

Test Year 2021 Forecast

NSP System Load Level Ranking	NSP System Load Forecast (MW)	Time Interval
1	8,794	07/22/2021 4:00 PM
2	8,728	07/22/2021 3:00 PM
3	8,699	07/22/2021 5:00 PM
4	8,572	07/22/2021 2:00 PM
5	8,536	07/21/2021 4:00 PM
6	8,465	07/21/2021 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 2021 Forecast

Date & Hour	Residential	Commercial Non Demand	C&I Demand	Lighting	Total
07/22/2021 04:00 PM	2,709	159	3,477	0	6,344
07/22/2021 03:00 PM	2,560	174	3,558	0	6,210
07/22/2021 05:00 PM	2,751	140	3,257	0	6,148
07/22/2021 02:00 PM	2,402	181	3,567	0	6,150
07/21/2021 04:00 PM	2,433	150	3,152	0	5,736
07/21/2021 03:00 PM	2,274	167	3,281	0	5,723
6 hour Total	15,128	972	20,292	0	32,834
D10S Allocator	38.55%	3.41%	58.04%	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 2014 through 2018 historical load shapes to create the initial 2021 load shape. Next, we forecast 2021 weather values (THI, CDD, HDD), which are used to forecast the 2021 typical meteorological year (TMY) weather normalized (WN) class load shape templates. Next, we used specialized software that removes the magnitude of loads by turning the WN 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 2021 WN load shape. This analysis is repeated for the 2022 and 2023 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	3.363
C&I Demand Primary Voltage	36.053
C&I Demand Transmission Transformed Voltage	313.398
C&I Demand Transmission Voltage	16.087
Total	386.901

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 2021 test year are $5.5 million and make up only 1.2 percent of total Other Production O&M costs. The remaining $441.7 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?

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

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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).

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 $9.7 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 2021 test year Other Production O&M costs.

Table 11

Classification of Other Production O&M Costs

NSPM-Minnesota Electric Jurisdiction

($ Thousands)

Expense Category	2021 Other Production O&M ($000)	Percent Energy	Percent Capacity	Energy-Related Portion	Capacity-Related Portion
Variable (Chemicals & Water Use)	$5,458.2	100.0%	0.0%	$5,458.2	$0.0
Fossil	$40,498.9	60.53%	39.47%	$24,514.4	$15,984.5
Combustion Turbine	$2,445.8	0.0%	100.0%	$0.0	$2,445.8
Nuclear	$291,329.2	80.97%	19.03%	$235,892.1	$55,437.1
Combined Cycle	$15,091.6	34.07%	65.93%	$5,142.1	$9,949.5
Hydro	$2,326.0	83.04%	16.96%	$1,931.6	$394.4
Wind	$66,347.7	93.28%	6.72%	$61,889.7	$4,457.9
Total Generation-Specific Other Production O&M	423,497.3	79.06%	20.94%	$334,828.1	$88,669.1
Corporate Other Production O&M not Assigned to Generation Type	$14,011.6	79.06%	20.94%	$11,077.9	$2,933.7
Regional Market Expense (FERC Codes 575.1 – 575.8)	$9,656.3	79.06%	20.94%	$7,634.5	$2,021.8
Total Other Production O&M	$447,165.2	79.06%	20.94%	$353,540.6	$93,624.6

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 Company has directly assigned all of the costs in FERC account 373 to the Street Lighting class and a portion of the costs is 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 2021 test year FERC Account 373 costs to the Street Lighting class in the 2021 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.

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[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).

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

A. Yes. The 2021 CCOSS includes $476.7 million Plant in Service for FERC account 364. Analysis of the FERC account detail shows that 77.7 percent of this account is the cost of the 432,869 wooden poles. Company-owned street lights are attached to 91,441 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 $46.5 million in 2021 test year FERC Account 364 costs to the Street Lighting class in the 2021 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	$472,655
2	Wood Pole Cost as a Percent of FERC 364	77.7%
3	FERC Acct 364 Pole Cost (line 1 x line 2)	$367,253
4	MN Company-Owned Street Lights on Wooden Poles	91,441
5	Total MN Wood Poles	432,869
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)	$77,580
8	Percent of Lighting Poles that only Serve Lighting	60%
9	FERC Acct 364 Direct Assignment to Lighting (line 7 x line 8)	$46,548

Q. IN TOTAL, HOW MUCH PLANT INVESTMENT IS DIRECTLY ASSIGNED TO THE STREET LIGHTING CLASS IN THE 2021 CCOSS?

A. In total, $118.0 million of distribution plant investment is directly assigned to the Street Lighting class in the 2021 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 insure 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 2021 Plant In Service ($000)	Demand Component	Customer Component
Distribution Substations	$696,372	X	
Primary Voltage Transformers	$44,785	X	
Overhead & Underground Primary Distribution Lines	$2,097,779	X	X
Overhead & Underground Secondary Distribution Lines	$340,312	X	X
Overhead & Underground Secondary Voltage Transformers	$413,286	X	X
Service Drops	$300,504	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 do 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 is 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 or Minimum Intercept are described on pages 92-94 of the NARUC manual. A Zero Intercept Study requires considerably more data and analysis than a Minimum System Study. A Zero Intercept Study requires the following data:

- A listing of all the configurations of equipment installed for the following distribution property units:
  - Overhead Primary Conductor;
  - Overhead Secondary Conductor;
  - Overhead Transformers;
  - Underground Primary Conductor;
  - Underground Secondary Conductor;
  - Underground Transformers; 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 of 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

Property Unit	**% of Costs Classified as Customer-Related**	
	Zero Intercept Method	**Minimum System Method**
Overhead Primary	34.9%	51.4%
Overhead Secondary	78.3%	89.6%
Overhead Transformers	72.7%	79.5%
Underground Primary	58.1%	53.2%
Underground Secondary	73.8%	100%
Underground Transformers	87.3%	51.5%

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)	34.9%	65.1%
Overhead Secondary (used Zero Intercept result)	78.3%	21.7%
Underground Primary (used Minimum System result)	53.2%	46.8%
Underground Secondary (used Zero Intercept result)	73.8%	26.2%
Weighted Average for Overhead and Underground Transformers (used Zero Intercept for OH Transformers; used Minimum System for UG Transformers)	63.7%	36.3%

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 2021 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 2021 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. ($000)**	**% Defic.**
1	Residential	181,242	14.9%	186,076	15.3%	194,241	16.0%	109,700	9.0%
2	Non-Demand	6,098	5.9%	6,502	6.3%	7,179	7.0%	114	0.1%
3	Demand	213,639	12.4%	208,539	12.2%	199,685	11.6%	291,411	17.0%
4	Street Ltg	4,773	17.5%	4,635	16.9%	4,647	17.0%	4,527	16.6%
5	Total	405,752	13.2%	405,752	13.2%	405,752	13.2%	405,752	13.2%
6	Cost Based Residential Customer Chg ($ per Resid customer per month)	$17.95		$18.76		$20.03		$6.23	

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 insure 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	73.1%	40.5%	12.3%	61.2%
Multi-Phase	26.9%	59.5%	87.7%	38.8%
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. Windsource and Renewable*Connect Riders – Capacity Credit

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

A. The capacity credit is a partial offset (credit) to the Windsource and Renewable*Connect purchased energy costs. It is intended to reflect the capacity value that Windsource and Renewable*Connect energy generation brings to the system power-supply portfolio. The amount of this "capacity-credit-based" transfer of costs from the Windsource 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 2021 – 2023 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. WHAT CHANGES ARE BEING PROPOSED FOR THE WINDSOURCE CAPACITY CREDIT RATE?

A. The Company is proposing a change to the Windsource capacity credit to update the combustion turbine value and MISO wind capacity factors. We adjusted the levelized cost of a combustion turbine to be consistent with the level filed in the Company's most recent Integrated Resource Plan in Docket No. E002/RP-19-368. We also reflect the MISO Planning Year 2018-2019

Wind Capacity Credit of 15.2 percent. After the Commission Order in this case, the Company would reflect the new capacity credit rate in the Company's next Windsource compliance filing.

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 period. The calculation is shown on Exhibit___(MAP-1), Schedule 12, pages 2-6 and results in $2,118,642 being transferred to base rates in the 2021 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 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 to increase in the CCRC from the current 0.3133¢ per kWh to 0.4798¢ per kWh to reflect 2021 test year CIP costs of $125,604,411. The Company is also proposing a corresponding decrease in the CAF from the current level of 0.1848¢ per kWh to 0.0183¢ 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 TARIFFS?

A. The following are the areas in the General Rules and Regulations 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 to 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 to my testimony. It is also shown on page 7, row 21 of Schedules 4, 6, and 8 to my testimony. The proposed increase in these charges reduces the proposed increase in retail revenues by Mr. Huso.

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 35 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

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	$942	$942 / $942	100.0%	0.0%
Nuclear	$4,952	$942 / $4,952	19.0%	81.0%
Fossil	$2,387	$942 / $2,387	39.5%	60.5%
Combined Cycle	$1,429	$942 / $1,429	65.9%	34.1%
Hydro	$5,557	$942 / $5,557	17.0%	83.0%
Wind	$14,024	$942 / $14,024	6.7%	93.3%

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.

Equipment Type	**% of Costs Classified as "Customer" Related**	
	Minimum/Zero Intercept Method	**Minimum Distribution System Method**
Overhead Lines Primary	34.9%	51.4%
Overhead Lines Secondary	78.3%	89.6%
Overhead Transformers	72.7%	79.5%
Underground Lines Primary	58.1%	53.2%
Underground Lines Secondary	73.8%	100%
Underground Transformers	87.3%	51.5%

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)	34.9%	65.1%
Overhead Lines Secondary (used Zero Intercept Result)	78.3%	21.7%
Underground Lines Primary (used Minimum System Result)	53.2%	46.8%
Underground Lines Secondary (used Zero Intercept Result)	73.8%	26.2%
Weighted Average for Overhead & Underground Transformers (used Zero Intercept for OH Transformers; used Minimum System for UG Transformers)	63.7%	36.3%

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**
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Rate Base Detail	4	Original Plant in Service	1-50
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		Present and Proposed Taxable Net Income	38A 38B
		Present and Proposed State and Federal Income Taxes	39A 39B
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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			• 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	> 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	- 2020 Customer forecast for TY2021	Forecasted annual bills / 12	Connection charge revenue is not 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	- 2020 Customer forecast for TY2021 and - 2020 customer accounting weighting factors	C11 X C11WAF	On page 103, the NARUC manual 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	- 2019 meter, CT and VT model inventory by customer class - 2020 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 2020 forecast for TY2021 - 2020 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 <u>primary</u> distribution line costs	Average monthly customers that are served by single phase primary distribution facilities	- Customer forecast for TY2021 and 2020 - 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.

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 TY2021 - 2020 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 TY2021 - 2020 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 2014-2018 synched to the 2020 kWh Sales Forecast for TY2021	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 2020 test year. Loads in the top 6 hours are used because based on 11 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 2014-2018 synched to the 2020 kWh Sales Forecast for TY2021		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.

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 2014-2018 synched to the 2020 kWh Sales Forecast for TY2021 - 2020 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 2014-2018 synched to the 2020 kWh Sales Forecast for TY2021 - 2020 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 2018 billing data for demand billed customers - 2020 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	- TY2021 load research class coincident demands - 2020 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 2014-2018 synched to the 2020 kWh Sales Forecast for TY2021 - Hourly marginal energy costs for the 2020 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	TY2021 sales forecast by customer class Less the TY2021 sales forecast for CIP exempt customers	2020 kWh Sales Forecast for TY2021		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.

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.

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

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.

Guide to the Class Cost of Service Study
CCOSS RELATED ANALYSIS

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 2021-2023 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 (2014-2018). The resulting load shapes for each class are synced up to the 2020 forecasts for the 2021-2023 Test Years. 2. Hourly system marginal energy costs are based on the 2021-2023 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 2020 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 2020 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 2021-2023 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 2018.
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 2019 inventory of meter models, CT models and VT models for each customer. Meter, CT and VT replacement costs are for 2019.
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.	2021-2023 budget detail of Other Production O&M expenses and 2020 Plant Stratification Analysis.

Guide to the Class Cost of Service Study
CCOSS RELATED ANALYSIS

Analysis	**Analysis Description**	**Data Sources and Associated Vintage**
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.	• TY2021 plant investment in FERC code 364 (overhead distribution poles). • The total number of overhead distribution poles based on 2013 data. • The number of street lights in overhead distribution area in 2019. • 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 on pages 45-46 of Michael Peppin's Direct Testimony.	2019 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.	2014 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 2021-2023 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.

Northern States Power Company
Electric Utility - Minnesota
Summary of 2021 Class Cost of Service Study ($000)

Docket No. E002/GR-20-723
Exhibit___(MAP-1), Schedule 3

UNADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	3,468,234	1,400,135	108,228	1,927,759	32,111
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,468	1,277	46	144	1
[3]	Unadjusted Operating Revenues (line 1 + line 2)	3,469,702	1,401,412	108,274	1,927,903	32,113
[4]	Present Rates (CCOSS page 2, line 2)	3,063,950	1,217,322	103,012	1,716,271	27,345
[5]	Unadjusted Deficiency (line 3 - line 4)	405,752	184,090	5,262	211,632	4,767
[6]	Defic / Pres (line 5 / line 4)	13.2%	15.1%	5.1%	12.3%	17.4%
[7]	**Ratio: Class % / Total %**	**1.00**	**1.14**	**0.39**	**0.93**	**1.32**

COST RESPONSIBILITIES FOR RATE DISCOUNTS

		Total	Residential	Non-Demand	Demand	Street Ltg
		[PROTECTED DATA 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 Dvlpmt Disc Cost Allocation (CCOSS page 2, line 8)					
						PROTECTED DATA ENDS]
[12]	Revenue Requirement Change (lines 10 & 11 - lines 8 & 9)	0	(2,848)	835	2,007	6

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[13]	Adjusted Rate Revenue Reqt (line 1 + line 12)	3,468,234	1,397,287	109,064	1,929,766	32,117
[14]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,468	1,277	46	144	1
[15]	Adjusted Operating Revenues (line 13 + line 14)	3,469,702	1,398,564	109,110	1,929,910	32,118
[16]	Present Rates (line 4)	3,063,950	1,217,322	103,012	1,716,271	27,345
[17]	Adjusted Deficiency (line 15 - line 16)	405,752	181,242	6,098	213,639	4,773
[18]	**Defic / Pres Rates (line 17 / line 16)**	**13.2%**	**14.9%**	**5.9%**	**12.4%**	**17.5%**
[19]	**Ratio: Class % / Total %**	**1.00**	**1.12**	**0.45**	**0.94**	**1.32**

PROPOSED REVENUE RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[20]	Proposed Rates (CCOSS page 3, line 3)	3,468,233	1,387,616	112,834	1,936,248	31,535
[21]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,468	1,277	46	144	1
[22]	Proposed Operating Revenues (line 20 + line 21)	3,469,701	1,388,893	112,880	1,936,392	31,536
[23]	Proposed Increase (line 22 - line 16)	405,751	171,571	9,868	220,121	4,191
[24]	Difference / Pres (line 23 / line 16)	13.2%	14.1%	9.6%	12.8%	15.3%
[25]	**Ratio: Class % / Total %**	**1.00**	**1.06**	**0.72**	**0.97**	**1.16**

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

Rate Base

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Plant In Service	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Production		12,031,701	4,114,850	7,883,088	347,364	7,535,725	5,493,586	1,441,614	568,265	32,259	33,763
2	Transmission		3,445,539	1,420,644	2,024,576	92,096	1,932,480	1,442,954	365,353	110,360	13,813	319
3	Distribution		4,087,440	2,701,286	1,252,579	160,968	1,091,611	897,865	192,638	1,084	24	133,576
4	General		1,826,313	768,882	1,041,780	56,048	985,732	731,322	186,658	63,449	4,303	15,650
5	Common		0	0	0	0	0	0	0	0	0	0
6	Total Plant In Service		21,390,993	9,005,662	12,202,023	656,476	11,545,547	8,565,727	2,186,263	743,158	50,399	183,308
7	Production		6,728,023	2,297,771	4,411,250	194,337	4,216,913	3,073,641	806,750	318,452	18,071	19,002
8	Transmission		775,371	320,390	454,946	20,680	434,266	324,022	81,968	24,612	3,664	35
9	Distribution		1,496,030	1,017,963	447,642	60,843	386,800	320,590	65,515	680	15	30,424
10	General		901,213	379,413	514,077	27,658	486,420	360,878	92,108	31,310	2,123	7,723
11	Common		0	0	0	0	0	0	0	0	0	0
12	Total Depreciation Reserve		9,900,637	4,015,536	5,827,916	303,517	5,524,399	4,079,132	1,046,341	375,053	23,873	57,185
13	**Net Plant In Service**		11,490,356	4,990,126	6,374,107	352,959	6,021,148	4,486,596	1,139,921	368,105	26,526	126,123
14	Deducts: Accum Defer Inc Tax		2,245,198	975,486	1,246,612	68,769	1,177,843	878,849	222,878	70,736	5,380	23,100
15	Constr Work In Progress		394,160	161,617	230,016	12,099	217,917	161,175	41,624	14,261	857	2,527
16	Fuel Inventory		84,026	27,109	56,620	2,473	54,146	39,213	10,377	4,314	241	298
17	Materials & Supplies		152,207	55,345	96,194	4,470	91,724	67,158	17,504	6,669	395	667
18	Prepayments		113,849	49,443	63,156	3,497	59,659	44,454	11,295	3,647	263	1,250
19	Non-Plant & Work Cash		(38,823)	(22,827)	(15,560)	(1,198)	(14,363)	(11,303)	(2,620)	(349)	(90)	(436)
20	Total Additions		705,418	270,687	430,426	21,342	409,083	300,697	78,179	28,542	1,666	4,306
21	**Rate Base**		9,950,576	4,285,326	5,557,921	305,532	5,252,388	3,908,444	995,222	325,911	22,812	107,329

Income Statement

			MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
22A	**Tot Oper Rev - Pres**		3,610,268	1,418,068	2,163,395	118,654	2,044,741	1,537,343	361,896	136,383	9,120	28,805
22B	**Tot Oper Rev - Prop**		4,016,019	1,589,640	2,393,384	128,522	2,264,863	1,702,266	402,175	150,377	10,045	32,996
23	Oper & Maint		2,407,999	915,523	1,476,703	74,441	1,402,261	1,032,186	266,147	98,149	5,779	15,774
24	Book Depr + IRS Int		737,364	305,813	423,508	22,592	400,916	296,960	75,902	26,350	1,704	8,043
25	Payroll, Rl Est & Prop Tax		219,745	97,942	119,466	6,888	112,578	84,111	21,236	6,751	481	2,337
26	Deferred Inc Tax & Net ITC		(84,474)	(45,577)	(36,962)	(2,722)	(34,241)	(26,486)	(6,322)	(1,304)	(129)	(1,935)
27A	Present Income Tax		(84,104)	(27,672)	(56,705)	(362)	(56,343)	(32,727)	(18,244)	(5,276)	(96)	273
27B	Proposed Income Tax		32,517	21,641	9,398	2,474	6,924	14,675	(6,667)	(1,255)	170	1,478
28	Allow Funds Dur Const		28,498	11,753	16,566	891	15,676	11,642	2,989	984	60	179
29A	**Present Return**		442,237	183,793	253,953	18,707	235,246	194,941	26,166	12,699	1,440	4,492
29B	**Proposed Return**		731,367	306,051	417,838	25,739	392,100	312,462	54,868	22,670	2,100	7,478
30A	**Pres Ret on Rt Base**		4.44%	4.29%	4.57%	6.12%	4.48%	4.99%	2.63%	3.90%	6.31%	4.18%
30B	**Prop Ret on Rt Base**		**7.35%**	7.14%	7.52%	8.42%	7.47%	7.99%	5.51%	6.96%	9.21%	6.97%
31A	**Pres Ret on Common**		4.67%	4.38%	4.91%	7.87%	4.74%	5.71%	1.22%	3.63%	8.24%	4.18%
31B	**Prop Ret on Common**		**10.21%**	9.81%	10.53%	12.26%	10.43%	11.44%	6.71%	9.46%	13.74%	9.48%

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

PRES vs Equal Rev Reqts

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**UnAdj Equal Rev Reqt @ 7.35%**		**3,468,234**	**1,400,135**	**2,035,987**	**108,228**	**1,927,759**	**1,425,700**	**365,170**	**128,785**	**8,104**	**32,111**
2	**Present Revenue**		**3,063,950**	**1,217,322**	**1,819,283**	**103,012**	**1,716,271**	**1,296,255**	**299,251**	**112,992**	**7,772**	**27,345**
3	**UnAdj Revenue Deficiency**		**404,284**	**182,813**	**216,704**	**5,216**	**211,488**	**129,445**	**65,919**	**15,793**	**332**	**4,766**
4	**UnAdj Deficiency / Present**		**13.19%**	**15.02%**	**11.91%**	**5.06%**	**12.32%**	**9.99%**	**22.03%**	**13.98%**	**4.27%**	**17.43%**
			[PROTECTED DATA 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**										
												PROTECTED DATA ENDS]
9	**Revenue Requirement Shift**		**0**	**(2,848)**	**2,842**	**835**	**2,007**	**8,134**	**(3,166)**	**(2,810)**	**(151)**	**6**
10	**Adj Equal Rev Reqt (Rows 1+9)**		**3,468,234**	**1,397,287**	**2,038,829**	**109,064**	**1,929,766**	**1,433,834**	**362,004**	**125,975**	**7,952**	**32,117**
11	**Adj Rev Defic vs Pres Rev (Row 2)**		**404,284**	**179,966**	**219,547**	**6,052**	**213,495**	**137,579**	**62,752**	**12,983**	**180**	**4,772**
12	**Adj Deficiency / Adj Present**		**13.19%**	**14.78%**	**12.07%**	**5.87%**	**12.44%**	**10.61%**	**20.97%**	**11.49%**	**2.32%**	**17.45%**
	Equal Customer Classification											
13	Min Sys & Service Drop		243,764	198,109	22,238	13,208	9,030	8,844	179	4	2	23,417
14	Energy Services		65,783	55,366	10,181	5,244	4,937	4,845	87	3	2	237
15	Total Customer **(Cusco)**		309,547	253,475	32,419	18,452	13,966	13,689	266	7	4	23,654
16	Ave Monthly Customers		1,339,326	1,176,591	134,820	86,122	48,698	48,203	473	13	9	27,915
17	Svc Drop Reqt	$ / Mo / Cust	$15.17	$14.03	$13.75	$12.78	$15.45	$15.29	$31.55	$27.46	$18.52	$69.90
18	Ener Svcs Reqt	$ / Mo / Cust	$4.09	$3.92	$6.29	$5.07	$8.45	$8.38	$15.28	$20.27	$18.44	$0.71
19	Total Reqt	$ / Mo / Cust	$19.26	$17.95	$20.04	$17.85	$23.90	$23.67	$46.83	$47.73	$36.96	$70.61
	Equal Energy Classification											
20	On Peak Rev Reqt		796,915	247,442	548,097	24,948	523,149	384,727	98,743	37,393	2,286	1,376
21	Off Peak Rev Reqt		838,635	279,864	554,205	23,260	530,946	381,624	102,527	44,337	2,458	4,566
22	Total Ener Rev Reqt		1,635,550	527,306	1,102,302	48,208	1,054,095	766,350	201,270	81,730	4,744	5,942
23	Annual MWh Sales		27,377,491.263	8,646,889	18,610,322	784,207	17,826,115	12,729,760	3,492,628	1,520,358	83,369	120,281
24	On Pk Reqt	Mills / kWh	29.108	28.616	29.451	31.813	29.347	30.223	28.272	24.595	27.424	11.441
25	Off Pk Reqt	Mills / kWh	30.632	32.366	29.779	29.660	29.785	29.979	29.355	29.162	29.484	37.957
26	Total Reqt	Mills / kWh	59.741	60.982	59.231	61.473	59.132	60.201	57.627	53.757	56.908	49.398
	Equal Demand Classification											
27	Energy-Related Prod		418,042	138,273	278,424	12,200	266,224	193,373	50,969	20,716	1,167	1,345
28	Capacity-Related Summer Peak Prod		306,270	127,066	179,205	8,185	171,019	128,269	32,458	9,691	601	0
29	Capacity-Related Winter Peak Prod		87,861	36,452	51,409	2,348	49,061	36,797	9,311	2,780	172	0
30	Total Capacity-Related Prod		394,131	163,518	230,614	10,533	220,080	165,066	41,769	12,471	773	0
31	Total Production		812,173	301,791	509,037	22,733	486,304	358,439	92,738	33,187	1,940	1,345
32	Transmission **(Transco)**		436,038	180,682	255,356	11,636	243,720	182,398	46,132	13,774	1,415	0
33	Primary Dist Subs		79,628	34,271	44,919	2,271	42,648	33,670	8,892	86	0	438
34	Prim Dist Lines		165,117	85,581	78,864	4,087	74,777	58,904	15,873	0	0	672
35	Second Dist, Trans		30,181	17,031	13,090	841	12,249	12,249	0	0	0	60
36	Total Distribution **(Disco)**		274,926	136,882	136,873	7,200	129,673	104,822	24,765	86	0	1,170
37	Total Demand Rev Reqt		1,523,137	619,355	901,266	41,568	859,698	645,660	163,635	47,047	3,355	2,516
38	Annual Billing kW		46,482,329	0	46,482,329	0	46,482,329	35,818,242	7,659,790	2,750,921	253,376	0
39	Base Rev Reqt	$ / kW	$0.00	$0.00	$5.99	$0.00	$5.73	$5.40	$6.65	$7.53	$4.60	$0.00
40	Summer Rev Reqt	$ / kW	$0.00	$0.00	$3.86	$0.00	$3.68	$3.58	$4.24	$3.52	$2.37	$0.00
41	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.11	$0.00	$1.06	$1.03	$1.22	$1.01	$0.68	$0.00
42	Prod Rev Reqt	$ / kW	$0.00	$0.00	$10.95	$0.00	$10.46	$10.01	$12.11	$12.06	$7.66	$0.00
43	Tran Rev Reqt	$ / kW	$0.00	$0.00	$5.49	$0.00	$5.24	$5.09	$6.02	$5.01	$5.59	$0.00
44	Dist Rev Reqt	$ / kW	$0.00	$0.00	$2.94	$0.00	$2.79	$2.93	$3.23	$0.03	$0.00	$0.00
45	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$19.39	$0.00	$18.50	$18.03	$21.36	$17.10	$13.24	$0.00
46	Tot Dmd Rev Reqt	Mills / kWh	55.635	71.628	48.428	53.007	48.227	50.721	46.852	30.945	40.245	20.915
47	Summer Billing kW		17,007,448	0	17,007,448	0	17,007,448	13,120,019	2,852,087	951,892	83,450	0
48	Winter Billing kW		29,474,881	0	29,474,881	0	29,474,881	22,698,223	4,807,704	1,799,028	169,925	0
49	Tot Summer Reqt	$ / kW	$0.00	$0.00	$24.96	$0.00	$23.82	$23.19	$27.29	$22.75	$17.39	$0.00
50	Tot Winter Reqt	$ / kW	$0.00	$0.00	$16.17	$0.00	$15.42	$15.04	$17.85	$14.11	$11.20	$0.00
51	Energy + Production **(Genco)**		2,447,723	829,096	1,611,340	70,941	1,540,399	1,124,790	294,008	114,917	6,684	7,287

2021 Class Cost of Service Study Detail ($000)

PROP vs Equal Rev Reqts

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**Proposed Ret On Rt Base**		**7.35%**	**7.14%**	**7.52%**	**8.42%**	**7.47%**	**7.99%**	**5.51%**	**6.96%**	**9.21%**	**6.97%**
2	**UnAdj Equalized Rev Reqt**		**3,468,234**	**1,400,135**	**2,035,987**	**108,228**	**1,927,759**	**1,425,700**	**365,170**	**128,785**	**8,104**	**32,111**
3	**Proposed Revenue**		**3,468,233**	**1,387,616**	**2,049,082**	**112,834**	**1,936,248**	**1,461,052**	**339,515**	**126,983**	**8,698**	**31,535**
4	**UnAdj Revenue Deficiency**		**0**	**12,519**	**(13,095)**	**(4,606)**	**(8,489)**	**(35,352)**	**25,655**	**1,803**	**(594)**	**576**
5	**UnAdj Deficiency / Proposed**		**0.00%**	**0.90%**	**-0.64%**	**-4.08%**	**-0.44%**	**-2.42%**	**7.56%**	**1%**	**-7%**	**1.83%**
			[PROTECTED DATA 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**										
												PROTECTED DATA ENDS]
10	**Revenue Requirement Shift**		**0**	**4,239**	**(4,246)**	**577**	**(4,823)**	**3,418**	**(4,739)**	**(3,318)**	**(183)**	**7**
11	**Adj Equal Rev (Rows 2+10)**		**3,468,234**	**1,404,374**	**2,031,741**	**108,805**	**1,922,936**	**1,429,118**	**360,431**	**125,467**	**7,920**	**32,118**
12	**Adj Rev Defic vs Prop Rev (Row 3)**		**0**	**16,758**	**(17,341)**	**(4,029)**	**(13,312)**	**(31,935)**	**20,916**	**(1,516)**	**(777)**	**583**
13	**Adj Deficiency / Adj Prop**		**0.00%**	**1.21%**	**-0.85%**	**-3.57%**	**-0.69%**	**-2.19%**	**6.16%**	**-1.19%**	**-8.94%**	**1.85%**
	Prop Customer Component											
14	Min Sys & Service Drop		241,367	195,081	23,390	14,049	9,341	9,165	170	4	2	22,896
15	Energy Services		65,778	55,359	10,182	5,245	4,937	4,845	87	3	2	237
16	Total Customer **(Cusco)**		307,145	250,440	33,572	19,294	14,278	14,010	256	7	4	23,133
17	Ave Monthly Customers		1,339,326	1,176,591	134,820	86,122	48,698	48,203	473	13	9	27,915
18	Svc Drop Reqt	$ / Mo / Cust	$15.02	$13.82	$14.46	$13.59	$15.98	$15.84	$29.92	$27.59	$19.82	$68.35
19	Ener Svcs Reqt	$ / Mo / Cust	$4.09	$3.92	$6.29	$5.08	$8.45	$8.38	$15.27	$20.27	$18.45	$0.71
20	Total Reqt	$ / Mo / Cust	$19.11	$17.74	$20.75	$18.67	$24.43	$24.22	$45.19	$47.86	$38.27	$69.06
	Prop Energy Component											
21	On Peak Rev Reqt		796,701	247,316	548,010	24,969	523,041	384,868	98,518	37,365	2,290	1,375
22	Off Peak Rev Reqt		838,384	279,720	554,101	23,279	530,823	381,763	102,294	44,303	2,462	4,563
23	Total Ener Rev Reqt		1,635,086	527,036	1,102,111	48,248	1,053,864	766,631	200,812	81,668	4,752	5,938
24	Annual MWh Sales		27,377,491	8,646,889	18,610,322	784,207	17,826,115	12,729,760	3,492,628	1,520,358	83,369	120,281
25	On Pk Reqt	Mills / kWh	29.101	28.602	29.447	31.840	29.341	30.234	28.207	24.576	27.469	11.435
26	Off Pk Reqt	Mills / kWh	30.623	32.349	29.774	29.684	29.778	29.990	29.289	29.140	29.534	37.935
27	Total Reqt	Mills / kWh	59.724	60.951	59.220	61.524	59.119	60.224	57.496	53.717	57.003	49.370
	Prop Demand Component											
28	Energy-Related Prod		424,556	136,278	286,968	14,222	272,747	213,387	38,110	19,749	1,502	1,309
29	Capacity-Related Summer Peak Prod		306,439	126,109	180,329	8,535	171,794	131,530	30,082	9,536	646	0
30	Capacity-Related Winter Peak Prod		87,909	36,177	51,732	2,449	49,283	37,732	8,630	2,736	185	0
31	Total Capacity-Related Prod		394,348	162,287	232,061	10,984	221,077	169,263	38,712	12,272	831	0
32	Total Production		818,904	298,565	519,030	25,206	493,824	382,649	76,821	32,021	2,333	1,309
33	Transmission **(Transco)**		431,632	176,283	255,349	12,367	242,981	188,376	39,759	13,237	1,609	0
34	Primary Dist Subs		80,662	34,217	46,009	2,485	43,524	35,729	7,746	49	0	436
35	Prim Dist Lines		164,569	84,454	79,454	4,340	75,114	60,995	14,120	0	0	661
36	Second Dist, Trans		30,237	16,622	13,557	895	12,662	12,662	0	0	0	58
37	Total Distribution **(Disco)**		275,467	135,292	139,020	7,720	131,300	109,386	21,866	49	0	1,154
38	Total Demand Rev Reqt		1,526,003	610,140	913,399	45,293	868,106	680,411	138,447	45,307	3,941	2,464
39	Annual Billing kW		46,482,329	0	46,482,329	0	46,482,329	35,818,242	7,659,790	2,750,921	253,376	0
40	Base Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$5.87	$5.96	$4.98	$7.18	$5.93	$0.00
41	Summer Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$3.70	$3.67	$3.93	$3.47	$2.55	$0.00
42	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$1.06	$1.05	$1.13	$0.99	$0.73	$0.00
43	Prod Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$10.62	$10.68	$10.03	$11.64	$9.21	$0.00
44	Tran Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$5.23	$5.26	$5.19	$4.81	$6.35	$0.00
45	Dist Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$2.82	$3.05	$2.85	$0.02	$0.00	$0.00
46	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$18.68	$19.00	$18.07	$16.47	$15.55	$0.00
47	Tot Dmd Rev Reqt	Mills / kWh	55.739	70.562	49.080	57.756	48.699	53.450	39.640	29.800	47.273	20.483
48	Summer Billing kW		17,007,448	0	17,007,448	0	17,007,448	13,120,019	2,852,087	951,892	83,450	0
49	Winter Billing kW		29,474,881	0	29,474,881	0	29,474,881	22,698,223	4,807,704	1,799,028	169,925	0
50	Tot Summer Reqt	$ / kW	$0.00	$0.00	$25.26	$0.00	$24.02	$24.30	$23.57	$22.03	$20.01	$0.00
51	Tot Winter Reqt	$ / kW	$0.00	$0.00	$16.41	$0.00	$15.59	$15.93	$14.82	$13.53	$13.36	$0.00
52	Energy + Production **(Genco)**		2,453,990	825,601	1,621,141	73,453	1,547,688	1,149,280	277,634	113,689	7,085	7,248
53	Prop Rev - Pres Rev (Pg 2)		404,283	170,295	229,799	9,822	219,977	164,797	40,264	13,990	926	4,190
54	Difference / Present		13.19%	13.99%	12.63%	9.53%	12.82%	12.71%	13.45%	12.38%	11.91%	15.32%

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

Original Plant in Service

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Summer Peak	D10S		1,946,748	809,254	1,137,494	52,015	1,085,479	814,181	205,997	61,489	3,811	0
2	WInter Peak	D10S		558,470	232,153	326,317	14,922	311,395	233,567	59,095	17,640	1,093	0
3	Total Peak	D10S		2,505,218	1,041,407	1,463,811	66,937	1,396,874	1,047,748	265,092	79,129	4,905	0
4	Base Load	E8760		6,993,898	2,256,378	4,712,732	205,876	4,506,856	3,263,926	863,748	359,100	20,082	24,787
5	Nuclear Fuel	E8760		2,532,586	817,065	1,706,545	74,551	1,631,994	1,181,912	312,775	130,035	7,272	8,976
6	Total	26.37%	120, 310-346	12,031,701	4,114,850	7,883,088	347,364	7,535,725	5,493,586	1,441,614	568,265	32,259	33,763
	Transmission												
7	Gen Step Up Base	E8760		90,040	29,049	60,672	2,650	58,022	42,020	11,120	4,623	259	319
8	Gen Step Up Peak	D10S		33,990	14,129	19,860	908	18,952	14,215	3,597	1,074	67	0
9	Total Gen Step Up			124,030	43,178	80,533	3,559	76,974	56,236	14,717	5,697	325	319
10	Bulk Transmission	D10S		3,313,643	1,377,465	1,936,178	88,537	1,847,641	1,385,853	350,636	104,664	6,488	0
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		7,866	0	7,866	0	7,866	866	0	0	7,000	0
13	Total		350-359	3,445,539	1,420,644	2,024,576	92,096	1,932,480	1,442,954	365,353	110,360	13,813	319
	Distribution:												
	Substations												
14	Generat Step Up	STRATH		3,046	1,031	2,006	88	1,918	1,397	367	146	8	9
15	Bulk Transmission	D10S		1,701	707	994	45	949	712	180	54	3	0
16	Distrib Function	D60Sub		696,372	307,900	384,545	20,363	364,183	301,208	73,363	(10,388)	0	3,926
17	Direct Assign	Dir Assign		17,965.347	0	17,965	0	17,965	385	6,335	11,245	0	0
18	Total		360-363	719,085	309,639	405,511	20,497	385,015	303,700	80,245	1,057	12	3,935
	Overhead Lines												
19	Primary Capacity 1 Phase	D61PS1Ph		154,519	118,109	35,565	4,050	31,515	23,822	7,693	0	0	845
20	Primary Capacity Multi Phase	D61PS		332,459	128,533	202,828	7,961	194,866	154,670	40,196	0	0	1,098
21	Primary Customer 1 Phase	C61PS1Ph		82,892	78,830	3,747	3,197	550	543	7	0	0	315
22	Primary Customer Multi Phase	C61PS		178,348	159,307	18,280	11,670	6,611	6,546	64	0	0	761
23	Total Primary			748,219	484,779	260,420	26,878	233,541	185,582	47,960	0	0	3,020
24	Second Capacity	D62SecL		38,027	19,479	18,451	1,146	17,305	17,305	0	0	0	96
25	Second Customer	C62Sec		136,814	122,252	13,979	8,955	5,024	5,024	0	0	0	584
26	Total Secondary			174,841	141,731	32,430	10,102	22,329	22,329	0	0	0	680
27	Street Lighting	DASL		46,548	0	0	0	0	0	0	0	0	46,548
28	Total		364,365	969,608	626,510	292,850	36,980	255,870	207,911	47,960	0	0	50,248
	Underground Lines												
29	Primary Capacity 1 Phase	D61PS1Ph		259,180	198,107	59,655	6,794	52,861	39,957	12,904	0	0	1,418
30	Primary Capacity Multi Phase	D61PS		372,509	144,017	227,262	8,920	218,341	173,303	45,038	0	0	1,231
31	Primary Customer 1 Phase	C61PS1Ph		294,540	280,107	13,313	11,360	1,953	1,929	24	0	0	1,120
32	Primary Customer Multi Phase	C61PS		423,332	378,135	43,390	27,699	15,691	15,539	152	0	0	1,806
33	Total Primary			1,349,560	1,000,367	343,619	54,773	288,846	230,728	58,118	0	0	5,575
34	Second Capacity	D62SecL		43,417	22,240	21,067	1,309	19,758	19,758	0	0	0	110
35	Second Customer	C62Sec		122,055	109,063	12,471	7,989	4,482	4,482	0	0	0	521
36	Total Secondary			165,471	131,303	33,538	9,298	24,240	24,240	0	0	0	631
37	Street Lighting	DASL		0	0	0	0	0	0	0	0	0	0
38	Total		366,367	1,515,032	1,131,670	377,157	64,071	313,086	254,968	58,118	0	0	6,205
	Line Transformers												
39	Primary	D61PS		44,785	17,314	27,323	1,072	26,250	20,835	5,415	0	0	148
40	Second Capacity	D62SecL		133,703	68,488	64,876	4,031	60,845	60,845	0	0	0	339
41	Second Customer	C62Sec		234,798	209,806	23,990	15,369	8,621	8,621	0	0	0	1,002
42	Total		368	413,286	295,608	116,189	20,472	95,717	90,302	5,415	0	0	1,489
	Services												
43	Second Capacity	D62NLL		78,908	59,437	19,471	1,554	17,917	17,917	0	0	0	0
44	Second Customer	C62NL		221,595	210,461	11,134	7,133	4,001	4,001	0	0	0	0
43	Total Services	C62NL	369	300,504	269,899	30,605	8,687	21,918	21,918	0	0	0	0
44	Meters	C12WM	370	98,452	67,960	30,266	10,261	20,005	19,066	900	26	12	225
45	Street Lighting	Dir Assign	373	71,474	0	0	0	0	0	0	0	0	71,474
46	**Total Distribution**			4,087,440	2,701,286	1,252,579	160,968	1,091,611	897,865	192,638	1,084	24	133,576
47	**General & Common Plant**	PTD	303, 389-399	1,826,313	768,882	1,041,780	56,048	985,732	731,322	186,658	63,449	4,303	15,650
48	Prelim Elec Plant			21,390,993	9,005,662	12,202,023	656,476	11,545,547	8,565,727	2,186,263	743,158	50,399	183,308
49	TBT Investment	NEPIS		0	0	0	0	0	0	0	0	0	0
50	**Elec Plant in Serv**			21,390,993	9,005,662	12,202,023	656,476	11,545,547	8,565,727	2,186,263	743,158	50,399	183,308

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

Accum Deprec; Net Plant

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		1,366,324	567,974	798,350	36,507	761,843	571,433	144,579	43,156	2,675	0
2	Decom Int Peaking	D10S		0	0	0	0	0	0	0	0	0	0
3	Decom Int Baseload	E8760		0	0	0	0	0	0	0	0	0	0
4	Nuclear Fuel	E8760		2,362,606	762,226	1,592,006	69,547	1,522,459	1,102,586	291,782	121,308	6,784	8,373
5	Base Load	E8760		2,999,093	967,570	2,020,893	88,283	1,932,611	1,399,623	370,389	153,988	8,612	10,629
6	Total		108,111,115,120.5	6,728,023	2,297,771	4,411,250	194,337	4,216,913	3,073,641	806,750	318,452	18,071	19,002
	Transmission												
7	Gen Step Up Base	E8760		9,972	3,217	6,719	294	6,426	4,654	1,232	512	29	35
8	Gen Step Up Peak	D10S		14,120	5,869	8,250	377	7,873	5,905	1,494	446	28	0
9	Total Gen Step Up			24,091	9,087	14,970	671	14,299	10,559	2,726	958	56	35
10	Bulk Transmission	D10S		748,873	311,303	437,570	20,009	417,561	313,199	79,243	23,654	1,466	0
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		2,407	0	2,407	0	2,407	265	0	0	2,142	0
13	Total		108,111,115,120.5	775,371	320,390	454,946	20,680	434,266	324,022	81,968	24,612	3,664	35
	Distribution												
14	Generat Step Up	STRATH		2,254	763	1,484	65	1,419	1,033	272	108	6	7
15	Bulk Transmission	D10S		619	257	362	17	345	259	66	20	1	0
16	Distrib Function	D60Sub		230,650	101,982	127,368	6,745	120,624	99,765	24,299	(3,441)	0	1,300
17	Direct Assign	Dir Assign		6,352	0	6,352	0	6,352	136	2,240	3,976	0	0
18	Total Substations			239,875	103,002	135,566	6,826	128,740	101,193	26,876	663	7	1,307
19	Overhead Lines	POL		351,469	227,101	106,154	13,405	92,749	75,365	17,385	0	0	18,214
20	Underground	PUL		479,648	358,278	119,405	20,284	99,121	80,721	18,400	0	0	1,965
21	Line Transformers	P68		174,585	124,874	49,082	8,648	40,434	38,147	2,287	0	0	629
22	Services	P69		180,217	161,862	18,354	5,210	13,144	13,144	0	0	0	0
23	Meters	C12WM		62,069	42,845	19,081	6,469	12,612	12,020	568	17	8	142
24	Street Lighting	P73		8,168	0	0	0	0	0	0	0	0	8,168
25	Total		108,111,115,120.5	1,496,030	1,017,963	447,642	60,843	386,800	320,590	65,515	680	15	30,424
26	**General & CommonPlant**	PTD	108,111,115,120.5	901,213	379,413	514,077	27,658	486,420	360,878	92,108	31,310	2,123	7,723
27	**Total Accum Depr**			9,900,637	4,015,536	5,827,916	303,517	5,524,399	4,079,132	1,046,341	375,053	23,873	57,185
28	**Net Elec Plant**			11,490,356	4,990,126	6,374,107	352,959	6,021,148	4,486,596	1,139,921	368,105	26,526	126,123
29	**Net Plant w/ TBT**			11,490,356	4,990,126	6,374,107	352,959	6,021,148	4,486,596	1,139,921	368,105	26,526	126,123
	Subtractions: Accum Defer Inc Tax												
	Production												
30	Peaking Plant	D10S		266,823	110,917	155,906	7,129	148,777	111,593	28,234	8,428	522	0
31	Base Load	E8760		912,757	294,475	615,047	26,868	588,179	425,967	112,726	46,865	2,621	3,235
32	Nuclear Fuel	E8760		(4,684)	(1,511)	(3,156)	(138)	(3,018)	(2,186)	(578)	(240)	(13)	(17)
33	Total		190,281,282,283	1,174,896	403,881	767,798	33,860	733,938	535,374	140,381	55,053	3,130	3,218
	Transmission												
34	Gen Step Up Base	E8760		15,829	5,107	10,666	466	10,200	7,387	1,955	813	45	56
35	Gen Step Up Peak	D10S		4,069	1,691	2,378	109	2,269	1,702	431	129	8	0
36	Total Gen Step Up			19,898	6,798	13,043	575	12,469	9,089	2,385	941	53	56
37	Bulk Transmission	D10S		715,051	297,243	417,808	19,105	398,702	299,053	75,664	22,585	1,400	0
38	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
39	Direct Assign	Dir Assign		1,569	0	1,569	0	1,569	173	0	0	1,396	0
40	Total		281,282,283	736,517	304,041	432,420	19,680	412,740	308,314	78,049	23,527	2,849	56
	Distribution												
41	Generat Step Up	STRATH		326	110	215	9	205	149	39	16	1	1
42	Bulk Transmission	D10S		251	104	147	7	140	105	27	8	0	0
43	Distrib Function	D60Sub		110,642	48,920	61,098	3,235	57,863	47,857	11,656	(1,650)	0	624
44	Direct Assign	Dir Assign		2,537	0	2,537	0	2,537	54	895	1,588	0	0
45	Total Substations			113,756	49,135	63,997	3,251	60,745	48,166	12,617	(39)	1	625
46	Overhead Lines	POL		147,927	95,583	44,678	5,642	39,037	31,720	7,317	0	0	7,666
47	Underground	PUL		233,533	174,440	58,136	9,876	48,260	39,302	8,959	0	0	957
48	Line Transformers	P68		57,668	41,248	16,212	2,857	13,356	12,600	756	0	0	208
49	Services	P69		18,452	16,573	1,879	533	1,346	1,346	0	0	0	0
50	Meters	C12WM		10,359	7,151	3,185	1,080	2,105	2,006	95	3	1	24
51	Street Lighting	P73		13,581	0	0	0	0	0	0	0	0	13,581
52	Total		281,282,283	595,277	384,130	188,088	23,239	164,849	135,139	29,742	(36)	3	23,059
53	**General & Common Plant**	PTD	281,282,283	143,730	60,511	81,988	4,411	77,577	57,555	14,690	4,993	339	1,232
54	**Total Deferred Tax**			2,650,420	1,152,562	1,470,293	81,190	1,389,103	1,036,382	262,863	83,537	6,321	27,565
55	Net Operating Loss (NOL) Carry F	NEPIS		(438,661)	(190,505)	(243,341)	(13,475)	(229,866)	(171,282)	(43,518)	(14,053)	(1,013)	(4,815)
56	Non-Plant Related	LABOR		33,439	13,430	19,660	1,053	18,607	13,749	3,534	1,252	72	350
57	**Accum Def W/ Adj**			2,245,198	975,486	1,246,612	68,769	1,177,843	878,849	222,878	70,736	5,380	23,100

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

Docket No. E002/GR-20-723
Exhibit___(MAP-1), Schedule 4

Additions: CWIP, Etc; Rate Base

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		27,134	11,279	15,854	725	15,129	11,348	2,871	857	53	0
2	Base Load	E8760		81,013	26,136	54,589	2,385	52,205	37,807	10,005	4,160	233	287
3	Nuclear Fuel	E8760		103,117	33,268	69,484	3,035	66,448	48,123	12,735	5,295	296	365
4	Total		107	211,264	70,684	139,927	6,145	133,782	97,278	25,611	10,311	582	653
	Transmission												
5	Gen Step Up Base	E8760		876	283	590	26	564	409	108	45	3	3
6	Gen Step Up Peak	D10S		3,025	1,258	1,768	81	1,687	1,265	320	96	6	0
7	Total Gen Step Up			3,901	1,540	2,358	107	2,251	1,674	428	141	8	3
8	Bulk Transmission	D10S		27,174	11,296	15,878	726	15,152	11,365	2,875	858	53	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
11	Total		107	31,075	12,836	18,236	833	17,403	13,039	3,304	999	62	3
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		13,255	5,861	7,319	388	6,932	5,733	1,396	(198)	0	75
15	Direct Assign	Dir Assign		1	0	1	0	1	0	0	1	0	0
16	Total Substations			13,256	5,861	7,321	388	6,933	5,733	1,397	(197)	0	75
17	Overhead Lines	POL		17,247	11,144	5,209	658	4,551	3,698	853	0	0	894
18	Underground	PUL		31,484	23,517	7,838	1,331	6,506	5,298	1,208	0	0	129
19	Line Transformers	P68		(670)	(479)	(188)	(33)	(155)	(146)	(9)	0	0	(2)
20	Services	P69		(101)	(91)	(10)	(3)	(7)	(7)	0	0	0	0
21	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
23	Total		107	61,216	39,952	20,169	2,341	17,828	14,576	3,449	(197)	0	1,095
24	**General & Common Plant**	PTD	107	90,606	38,145	51,684	2,781	48,903	36,282	9,260	3,148	213	776
25	**Total CWIP**			394,160	161,617	230,016	12,099	217,917	161,175	41,624	14,261	857	2,527
26	Fuel Inventory	E8760	151,152	84,026	27,109	56,620	2,473	54,146	39,213	10,377	4,314	241	298
	Materials & Supplies												
27	Production	P10		136,170	46,570	89,218	3,931	85,286	62,174	16,316	6,431	365	382
28	Trans & Distr	TD		16,036	8,775	6,977	539	6,438	4,983	1,188	237	29	285
29	Total		154	152,207	55,345	96,194	4,470	91,724	67,158	17,504	6,669	395	667
	Prepayments												
30	Miscellaneous	NEPIS		113,849	49,443	63,156	3,497	59,659	44,454	11,295	3,647	263	1,250
31	Fuel	E8760		0	0	0	0	0	0	0	0	0	0
32	Insurance	NEPIS	135,143,184,186,232	0	0	0	0	0	0	0	0	0	0
33	Total		235,252,165	113,849	49,443	63,156	3,497	59,659	44,454	11,295	3,647	263	1,250
34	Non-Plant Assets & Liab	LABOR	190,283,	104,503	41,970	61,440	3,292	58,148	42,967	11,043	3,914	225	1,092
35	Working Cash	PT0	calculated	(143,326)	(64,797)	(77,001)	(4,490)	(72,511)	(54,270)	(13,663)	(4,263)	(314)	(1,528)
36	**Total Additions**			705,418	270,687	430,426	21,342	409,083	300,697	78,179	28,542	1,666	4,306
37	**Total Rate Base**			9,950,576	4,285,326	5,557,921	305,532	5,252,388	3,908,444	995,222	325,911	22,812	107,329
38	**Common Rate Base (@ 52.50%)**			5,224,052.4	2,249,796	2,917,908	160,405	2,757,504	2,051,933	522,492	171,103	11,976	56,348

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

	Operating Rev (Cal Month)			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Retail Revenue	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Present Rate Revenue	R01; (calc)	440, 442,444,445	3,063,950.059	1,217,322	1,819,283	103,012	1,716,271	1,296,255	299,251	112,992	7,772	27,345
2	Proposed Rate Revenue	PROREV; (calc)		3,468,233	1,387,616	2,049,082	112,834	1,936,248	1,461,052	339,515	126,983	8,698	31,535
3	Equal Rate Revenue			3,468,234	1,400,135	2,035,987	108,228	1,927,759	1,425,700	365,170	128,785	8,104	32,111
	Other Retail Revenue												
4	Interdepartmental	R01; R02		693	275	411	23	388	293	68	26	2	6
5	Gross Earnings Tax	R01; R02	408	0	0	0	0	0	0	0	0	0	0
6	CIP Adjustment to Program Costs	E99XCIP	456	0	0	0	0	0	0	0	0	0	0
7	**Tot Other Retail Rev**			693	275	411	23	388	293	68	26	2	6
	Other Operating Revenue												
8	Interchg Prod Capacity	P10	456	414,931	141,907	271,860	11,979	259,881	189,454	49,716	19,597	1,113	1,164
9	Interchg Prod Energy	E8760	456	0	0	0	0	0	0	0	0	0	0
10	Interchg Tr Bulk Supply	D10S	456	0	0	0	0	0	0	0	0	0	0
11	Dist Int Sales; Oth Serv	E8760	412,451,456	997	322	672	29	643	465	123	51	3	4
12	Dist Overhd Line Rent	POL	454	4,665	3,014	1,409	178	1,231	1,000	231	0	0	242
13	Connection Charges	C11	451	1,923	1,690	194	124	70	69	1	0	0	40
14	Sales For Resale	E8760	447	0	0	0	0	0	0	0	0	0	0
15	Joint Op Agree-Other PSCo Rev	D10S	456	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0
16	Misc Ancillary Trans Rev	D10S		203,988	84,797	119,191	5,450	113,741	85,313	21,585	6,443	399	0
17	MISO	D10S	456	(94,594)	(39,322)	(55,272)	(2,527)	(52,744)	(39,562)	(10,010)	(2,988)	(185)	0
18	Other	D10S	451,456,457	8,266	3,436	4,830	221	4,609	3,457	875	261	16	0
19	Late Pay Chg - Pres	R16C; R02		5,448	4,628	817	164	653	597	56	0	0	3
20	**Tot Other Op - Pres**		450	545,625	200,471	343,701	15,618	328,083	240,795	62,577	23,365	1,346	1,453
21	Incr Misc Serv - Prop	C62NL		667	633	34	21	12	12	0	0	0	0
22	Incr Inter-Dept'l - Prop	R01; R02		82	33	49	3	46	35	8	3	0	1
23	Incr Late Pay - Prop	(R16C); R02		719	611	108	22	86	79	7	0	0	0
	Tot Incr Other Op			1,468	1,277	190	46	144	126	15	3	0	1
24	**Tot Other Op - Prop**			547,093	201,748	343,891	15,664	328,227	240,920	62,592	23,368	1,346	1,454
25	**Tot Oper Rev - Pres**			3,610,268	1,418,068	2,163,395	118,654	2,044,741	1,537,343	361,896	136,383	9,120	28,805
26	**Tot Oper Rev - Prop**			4,016,019	1,589,640	2,393,384	128,522	2,264,863	1,702,266	402,175	150,377	10,045	32,996
	Operating & Maint (Pg 1 of 2)												
	Production Expen												
27	**Fuel**	E8760	501,518,547	620,591	200,216	418,176	18,268	399,908	289,619	76,643	31,864	1,782	2,199
	Purchased Power												
28	Purchases: Cap Peak	D10S		102,486	42,603	59,883	2,738	57,145	42,862	10,845	3,237	201	0
29	Purchases: Cap Base	D10S		38,137	15,853	22,284	1,019	21,265	15,950	4,036	1,205	75	0
30	Purchases: Demand		555	140,623	58,456	82,167	3,757	78,409	58,812	14,880	4,442	275	0
31	Purchases: Other Energy	E8760	555	299,393	96,591	201,742	8,813	192,928	139,721	36,975	15,372	860	1,061
32	Tot Non-Assoc Purch			440,016	155,047	283,908	12,570	271,338	198,534	51,855	19,814	1,135	1,061
33	Interchg Agr Capacity	P10WoN	557	42,883	14,887	27,883	1,232	26,652	19,465	5,096	1,978	113	112
34	Interchg Agr Energy	E8760	557	14,848	4,790	10,005	437	9,568	6,929	1,834	762	43	53
35	Tot Wis Interchg Purch			57,731	19,678	37,888	1,669	36,220	26,394	6,930	2,741	155	165
36	**Tot Purchased Power**			497,747	174,725	321,797	14,239	307,558	224,928	58,785	22,555	1,290	1,226
	Other Production		500,502,505-507 509-514,517-519,520,										
37	Capacity Related	D10S	523-525,528-532,535,	93,625	38,919	54,705	2,502	52,204	39,156	9,907	2,957	183	0
38	Energy Related	E8760	539,543-546,548-550	353,541	114,060	238,228	10,407	227,821	164,991	43,662	18,152	1,015	1,253
39	Total Other Produc	20.94%	552-554,556,557 575.1-575.8	447,165.178	152,979	292,933	12,909	280,025	204,147	53,569	21,110	1,198	1,253
40	**Total Production**			1,565,503	527,919	1,032,906	45,416	987,490	718,693	188,997	75,528	4,271	4,678
41	**Transmission Exp**	D10S	560-563, 565-568 570-573	247,205	102,762	144,443	6,605	137,838	103,388	26,158	7,808	484	0

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

Operating & Maint (Pg 2 of 2)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Distribution Expen	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Supervision & Eng'rg	ZDTS	580,590	12,724	7,876	4,134	541	3,593	2,934	649	9	1	714
2	Load Dispatching	T20D80	581	1,302	569	727	37	690	559	137	(7)	1	6
3	Substations	P61	582,591,592	7,801	3,359	4,399	222	4,177	3,294	870	11	0	43
4	Overhead Lines	POL	583,593	44,685	28,873	13,496	1,704	11,792	9,582	2,210	0	0	2,316
5	Underground Lines	PUL	584, 594	19,589	14,633	4,877	828	4,048	3,297	751	0	0	80
6	Line Transformers	P68	595	1,406	1,006	395	70	326	307	18	0	0	5
7	Meters	C12WM	586,597,598	2,096	1,447	644	218	426	406	19	1	0	5
8	Customer Install'n	OXDTS	587	3,853	2,431	1,193	150	1,043	848	195	0	0	229
9	Street Lighting	Dir Assign	585,596	2,289	0	0	0	0	0	0	0	0	2,289
10	Miscellaneous	OXDTS	588	27,808	17,543	8,609	1,081	7,528	6,120	1,406	2	0	1,656
11	Rents (Pole Attachmts)	POL	589	3,822	2,470	1,154	146	1,009	820	189	0	0	198
12	**Total Distribution**			127,374	80,205	39,629	4,998	34,631	28,167	6,446	16	2	7,540
13	**Customer Accounting**	C11WA	901-905	58,738	49,395	9,162	4,700	4,462	4,379	79	3	2	180
14	**Sales, Econ Dvlp & Other**	R01	912	282	112	167	9	158	119	28	10	1	3
	Admin & General												
15	Salaries	LABOR	920	77,920	31,294	45,811	2,454	43,357	32,037	8,234	2,918	167	814
16	Office Supplies	OXTS	921	56,098	21,326	34,405	1,734	32,671	24,047	6,202	2,287	135	367
17	Admin Transfer Credit	OXTS	922	(47,871)	(18,199)	(29,359)	(1,480)	(27,880)	(20,521)	(5,293)	(1,952)	(115)	(313)
18	Outside Services	LABOR	923	15,400	6,185	9,054	485	8,569	6,332	1,627	577	33	161
19	Property Insurance	NEPIS	924	5,808	2,522	3,222	178	3,043	2,268	576	186	13	64
20	Pensions & Benefits	LABOR	926	66,638	26,763	39,179	2,099	37,079	27,399	7,042	2,496	143	697
21	Injuries & Claims	LABOR	925	11,784	4,733	6,928	371	6,557	4,845	1,245	441	25	123
22	Regulatory Exp	R01; R02	928	6,040	2,400	3,586	203	3,383	2,555	590	223	15	54
23	General Advertising	OXTS	930.1	115	44	71	4	67	49	13	5	0	1
24	Contributions	OXTS		0	0	0	0	0	0	0	0	0	0
25	Misc General Exp	OXTS	929, 930.2	(757)	(288)	(465)	(23)	(441)	(325)	(84)	(31)	(2)	(5)
26	Rents	OXTS	931	34,072	12,953	20,896	1,053	19,843	14,605	3,767	1,389	82	223
27	Maint of General Plant	OXTS	935	141	54	86	4	82	60	16	6	0	1
28	Total			225,387	89,786	133,414	7,083	126,331	93,353	23,935	8,545	498	2,186
	Cust Service & Info												
29	Cust Assist Exp - Non-CIP	C11P10	908	2,359	1,439	891	110	782	581	142	56	3	28
30	CIP Total	E99XCIP	908	125,604.411	41,490	83,538	3,762	79,776	60,751	14,515	4,109	400	577
31	Instructional Advertising	C11P10	909	506	309	191	24	168	125	30	12	1	6
32	Total			128,469	43,238	84,620	3,896	80,725	61,456	14,688	4,177	404	611
33	Amortizations	LABOR		55,040	22,105	32,360	1,734	30,626	22,630	5,816	2,061	118	575
34	**Total O&M Expense**			2,407,999	915,523	1,476,703	74,441	1,402,261	1,032,186	266,147	98,149	5,779	15,774

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

Book Depreciation

		Alloc	FERC Accounts	1=2+3+10 MN	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5=6 to 9 Demand	6 Second	7 Primary	8 Tr Transf	9 Trans	10 St Ltg
	Production												
1	Peaking Plant	D10S		103,164	42,885	60,279	2,756	57,523	43,146	10,916	3,259	202	0
2	Base Load	E8760		321,688	103,783	216,764	9,469	207,295	150,126	39,728	16,517	924	1,140
3	Total		403,413	424,852	146,668	277,044	12,226	264,818	193,272	50,645	19,776	1,126	1,140
	Transmission												
4	Gen Step Up Base	E8760		1,734	559	1,168	51	1,117	809	214	89	5	6
5	Gen Step Up Peak	D10S		1,014	422	593	27	566	424	107	32	2	0
6	Total Gen Step Up			2,748	981	1,761	78	1,683	1,233	321	121	7	6
7	Bulk Transmission	D10S		68,300	28,392	39,908	1,825	38,083	28,565	7,227	2,157	134	0
8	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
9	Direct Assign	Dir Assign		165	0	165	0	165	18	0	0	147	0
10	Total		403,413	71,214	29,373	41,834	1,903	39,931	29,817	7,549	2,278	288	6
	Distribution												
11	Generat Step Up	STRATH		69	23	45	2	43	31	8	3	0	0
12	Bulk Transmission	D10S		38	16	22	1	21	16	4	1	0	0
13	Distrib Function	D60Sub		15,644	6,917	8,639	457	8,181	6,766	1,648	(233)	0	88
14	Direct Assign	Dir Assign		392	0	392	0	392	8	138	246	0	0
15	Total Substations		403,413	16,143	6,956	9,099	460	8,638	6,822	1,799	17	0	88
16	Overhead Lines	POL		33,462	21,621	10,107	1,276	8,830	7,175	1,655	0	0	1,734
17	Underground	PUL		38,600	28,832	9,609	1,632	7,977	6,496	1,481	0	0	158
18	Line Transformers	P68		11,209	8,017	3,151	555	2,596	2,449	147	0	0	40
19	Services	P69		10,570	9,494	1,077	306	771	771	0	0	0	0
20	Meters	C12WM		4,350	3,003	1,337	453	884	842	40	1	1	10
21	Street Lighting	P73		3,810	0	0	0	0	0	0	0	0	3,810
22	Total		403,413	118,144	77,924	34,379	4,683	29,696	24,556	5,121	18	1	5,841
23	**General & Common Plant**	PTD	403,413	123,154	51,848	70,250	3,780	66,471	49,315	12,587	4,279	290	1,055
24	**Total Book Deprec**		403,404	737,364	305,813	423,508	22,592	400,916	296,960	75,902	26,350	1,704	8,043

Real Estate & Property Tax

		Alloc	FERC Accounts	1=2+3+10 MN	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5=6 to 9 Demand	6 Second	7 Primary	8 Tr Transf	9 Trans	10 St Ltg
	Production												
25	Peaking Plant	D10S		24,514	10,190	14,323	655	13,668	10,252	2,594	774	48	0
26	Base Load	E8760		68,436	22,079	46,114	2,015	44,100	31,938	8,452	3,514	197	243
27	Total		408.1	92,949	32,269	60,438	2,669	57,768	42,190	11,046	4,288	244	243
	Transmission												
28	Gen Step Up Base	E8760		1,147.2295	370	773	34	739	535	142	59	3	4
29	Gen Step Up Peak	D10S		433.0721	180	253	12	241	181	46	14	1	0
30	Total Gen Step Up			1,580.3016	550	1,026	45	981	717	188	73	4	4
31	Bulk Transmission	D10S		42,220.0877	17,551	24,669	1,128	23,541	17,658	4,468	1,334	83	0
32	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
33	Direct Assign	Dir Assign		100	0	100	0	100	11	0	0	89	0
34	Total		408.1	43,900.609	18,101	25,796	1,173	24,622	18,385	4,655	1,406	176	4
	Distribution												
35	Generat Step Up	STRATH		41	14	27	1	26	19	5	2	0	0
36	Bulk Transmission	D10S		23	10	13	1	13	10	2	1	0	0
37	Distrib Function	D60Sub		9,384	4,149	5,182	274	4,908	4,059	989	(140)	0	53
38	Direct Assign	Dir Assign		242	0	242	0	242	5	85	152	0	0
39	Total Substations			9,690	4,173	5,464	276	5,188	4,092	1,081	14	0	53
40	Overhead Lines	POL		13,066	8,442	3,946	498	3,448	2,802	646	0	0	677
41	Underground	PUL		20,416	15,250	5,082	863	4,219	3,436	783	0	0	84
42	Line Transformers	P68		5,569	3,983	1,566	276	1,290	1,217	73	0	0	20
43	Services	P69		4,049	3,637	412	117	295	295	0	0	0	0
44	Meters	C12WM		1,327	916	408	138	270	257	12	0	0	3
45	Street Lighting	P73		963	0	0	0	0	0	0	0	0	963
46	Total		408.1	55,080	36,401	16,879	2,169	14,710	12,099	2,596	15	0	1,800
47	**General & Common Plant**	PTD	408.1	0	0	0	0	0	0	0	0	0	0
48	**Tot Rl Est & Pr Tax**			191,930	86,771	103,112	6,012	97,100	72,674	18,297	5,709	421	2,047
49	Gross Earnings Tax	R01; R02		0	0	0	0	0	0	0	0	0	0
50	Payroll Taxes	LABOR		27,815	11,171	16,354	876	15,477	11,437	2,939	1,042	60	291
51	**Tot Non-Inc Taxes**			219,745	97,942	119,466	6,888	112,578	84,111	21,236	6,751	481	2,337

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

Provision For Defer Inc Tax

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		(2,708)	(1,126)	(1,582)	(72)	(1,510)	(1,133)	(287)	(86)	(5)	0
2	Nuclear Fuel	E8760		(2,384)	(769)	(1,607)	(70)	(1,537)	(1,113)	(294)	(122)	(7)	(8)
3	Base Load	E8760		66,044	21,307	44,503	1,944	42,559	30,822	8,156	3,391	190	234
4	Total		410, 411	60,952	19,412	41,314	1,802	39,512	28,576	7,575	3,183	177	226
	Transmission												
5	Gen Step Up Base	E8760		1,219	393	822	36	786	569	151	63	4	4
6	Gen Step Up Peak	D10S		432	180	252	12	241	181	46	14	1	0
7	Total Gen Step Up			1,651	573	1,074	47	1,027	750	196	76	4	4
8	Bulk Transmission	D10S		13,974	5,809	8,165	373	7,792	5,844	1,479	441	27	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		24	0	24	0	24	3	0	0	22	0
11	Total		410, 411	15,650	6,382	9,264	421	8,843	6,597	1,675	518	53	4
	Distribution												
12	Generat Step Up	STRATH		(28)	(9)	(18)	(1)	(17)	(13)	(3)	(1)	(0)	(0)
13	Bulk Transmission	D10S		(7)	(3)	(4)	(0)	(4)	(3)	(1)	(0)	(0)	0
14	Distrib Function	D60Sub		(768)	(340)	(424)	(22)	(402)	(332)	(81)	11	0	(4)
15	Direct Assign	Dir Assign		(51)	0	(51)	0	(51)	(1)	(18)	(32)	(0)	0
16	Total Substations			(853)	(352)	(497)	(23)	(473)	(349)	(103)	(22)	(0)	(4)
17	Overhead Lines	POL		1,973	1,275	596	75	521	423	98	0	0	102
18	Underground	PUL		(2,369)	(1,769)	(590)	(100)	(489)	(399)	(91)	0	0	(10)
19	Line Transformers	P68		(2,173)	(1,554)	(611)	(108)	(503)	(475)	(28)	0	0	(8)
20	Services	P69		(1,681)	(1,510)	(171)	(49)	(123)	(123)	0	0	0	0
21	Meters	C12WM		439	303	135	46	89	85	4	0	0	1
22	Street Lighting	P73		(537)	0	0	0	0	0	0	0	0	(537)
23	Total		410, 411	(5,200)	(3,607)	(1,138)	(159)	(979)	(837)	(121)	(22)	(0)	(455)
24	**General & Common Plant**	PTD	410, 411	(2,098)	(883)	(1,197)	(64)	(1,132)	(840)	(214)	(73)	(5)	(18)
25	**Net Operating Loss (NOL) Carry**	NEPIS		(155,847)	(67,682)	(86,454)	(4,787)	(81,666)	(60,853)	(15,461)	(4,993)	(360)	(1,711)
26	**Non - Plant Related**	LABOR	410, 411	3,292	1,322	1,935	104	1,832	1,354	348	123	7	34
27	**Tot Prov For Defer**			(83,251)	(45,056)	(36,275)	(2,684)	(33,591)	(26,003)	(6,198)	(1,263)	(127)	(1,920)

Inv Tax Credit; Total Oper Exp

				MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
	Production												
28	Peaking Plant	D10S		(260)	(108)	(152)	(7)	(145)	(109)	(27)	(8)	(1)	0
29	Base Load	E8760		(538)	(174)	(363)	(16)	(347)	(251)	(66)	(28)	(2)	(2)
30	Total		411	(798)	(282)	(515)	(23)	(492)	(360)	(94)	(36)	(2)	(2)
	Transmission												
31	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
32	Gen Step Up Peak	D10S		0	0	0	0	0	0	0	0	0	0
33	Total Gen Step Up			0	0	0	0	0	0	0	0	0	0
34	Bulk Transmission	D10S		(150)	(62)	(88)	(4)	(84)	(63)	(16)	(5)	(0)	0
35	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
36	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
37	Total		411	(150)	(62)	(88)	(4)	(84)	(63)	(16)	(5)	(0)	0
	Distribution												
38	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
39	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
40	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
41	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
42	Total Substations			0	0	0	0	0	0	0	0	0	0
43	Overhead Lines	POL		(268)	(173)	(81)	(10)	(71)	(57)	(13)	0	0	(14)
44	Underground	PUL		0	0	0	0	0	0	0	0	0	0
45	Line Transformers	P68		0	0	0	0	0	0	0	0	0	0
46	Services	P69		0	0	0	0	0	0	0	0	0	0
47	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
48	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
49	Total		411	(268)	(173)	(81)	(10)	(71)	(57)	(13)	0	0	(14)
50	**General & Common Plant**	PTD	411	(7)	(3)	(4)	(0)	(4)	(3)	(1)	(0)	(0)	(0)
51	**Net Inv Tax Credit**			(1,223)	(520)	(687)	(37)	(650)	(483)	(124)	(41)	(2)	(16)
28	TBT Misc Net Exp	NEPIS		0	0	0	0	0	0	0	0	0	0
52	**Total Operating Exp**			**3,280,633**	**1,273,701**	**1,982,714**	**101,199**	**1,881,515**	**1,386,770**	**356,964**	**129,946**	**7,835**	**24,218**
53A	**Pres Op Inc Before Inc Tax**			**329,635**	**144,368**	**180,681**	**17,454**	**163,227**	**150,572**	**4,932**	**6,438**	**1,284**	**4,586**
53B	**Prop Op Inc Before Inc Tax**			**735,386**	**315,939**	**410,670**	**27,322**	**383,348**	**315,495**	**45,211**	**20,431**	**2,210**	**8,777**

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

Tax Deprec; Inc Tax & Return

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		114,932	47,777	67,155	3,071	64,084	48,068	12,162	3,630	225	0
2	Nuclear Fuel	E8760		92,104	29,715	62,063	2,711	59,351	42,983	11,375	4,729	264	326
3	Base Load	E8760		651,621	210,226	439,085	19,181	419,903	304,100	80,475	33,457	1,871	2,309
4	Total		tax books	858,656	287,718	568,303	24,964	543,339	395,150	104,012	41,817	2,361	2,636
	Transmission												
5	Gen Step Up Base	E8760		6,368	2,054	4,291	187	4,104	2,972	786	327	18	23
6	Gen Step Up Peak	D10S		2,302	957	1,345	61	1,283	963	244	73	5	0
7	Total Gen Step Up			8,670	3,011	5,636	249	5,387	3,934	1,030	400	23	23
8	Bulk Transmission	D10S		127,356	52,941	74,415	3,403	71,012	53,264	13,476	4,023	249	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		269	0	269	0	269	30	0	0	240	0
11	Total		tax books	136,295	55,952	80,320	3,652	76,668	57,228	14,506	4,422	512	23
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		16	7	9	0	9	7	2	1	0	0
14	Distrib Function	D60Sub		15,259	6,747	8,426	446	7,980	6,600	1,608	(228)	0	86
15	Direct Assign	Dir Assign		245	0	245	0	245	5	86	153	0	0
16	Total Substations			15,520	6,753	8,680	447	8,234	6,612	1,695	(74)	0	86
17	Overhead Lines	POL		40,171	25,957	12,133	1,532	10,601	8,614	1,987	0	0	2,082
18	Underground	PUL		39,425	29,449	9,815	1,667	8,147	6,635	1,512	0	0	161
19	Line Transformers	P68		9,602	6,868	2,699	476	2,224	2,098	126	0	0	35
20	Services	P69		5,520	4,958	562	160	403	403	0	0	0	0
21	Meters	C12WM		5,694	3,930	1,750	593	1,157	1,103	52	2	1	13
22	Street Lighting	P73		2,474	0	0	0	0	0	0	0	0	2,474
23	Total		tax books	118,405	77,915	35,640	4,875	30,765	25,464	5,373	(72)	1	4,851
24	**General & Common Plant**	PTD	tax books	141,821	59,707	80,899	4,352	76,546	56,790	14,495	4,927	334	1,215
25	Net Operating Loss (NOL) Carry F	NEPIS		0	0	0	0	0	0	0	0	0	0
26	**Total Tax Deprec**			1,255,177	481,292	765,161	37,842	727,318	534,632	138,385	51,094	3,207	8,724
27	Interest Expense		427,431	198,016.46	85,278	110,603	6,080	104,523	77,778	19,805	6,486	454	2,136
28	Other Tax Timing Differ	LABOR		1,832	736	1,077	58	1,019	753	194	69	4	19
29	Meals & Enter	LABOR		1,112	446	654	35	619	457	117	42	2	12
30	Total Tax Deductions			1,456,137	567,752	877,494	44,015	833,479	613,620	158,501	57,689	3,668	10,891
	Inc Tax Additions												
31	Book Depreciation			737,364	305,813	423,508	22,592	400,916	296,960	75,902	26,350	1,704	8,043
32	Deferred Inc Tax & ITC			(84,474.43)	(45,577)	(36,962)	(2,722)	(34,241)	(26,486)	(6,322)	(1,304)	(129)	(1,935)
33	Nuclear Fuel Book Burn	E8760		99,007	31,942	66,714	2,914	63,800	46,205	12,227	5,083	284	351
34	Tax Capitalized Leases	PTD		39,460	16,613	22,509	1,211	21,298	15,801	4,033	1,371	93	338
35	Avoided Tax Interest	RTBASE		15,847	6,825	8,852	487	8,365	6,225	1,585	519	36	171
36	Total Tax Additions			807,203	315,615	484,620	24,482	460,138	338,704	87,426	32,020	1,989	6,967
37	**Total Inc Tax Adjustments**			(648,934)	(252,137)	(392,874)	(19,533)	(373,341)	(274,916)	(71,076)	(25,670)	(1,679)	(3,923)
38A	**Pres Taxable Net Income**			(319,299)	(107,769)	(212,193)	(2,079)	(210,114)	(124,344)	(66,144)	(19,232)	(394)	663
38B	**Prop Taxable Net Income**			86,452	63,802	17,796	7,789	10,007	40,579	(25,864)	(5,239)	531	4,854
39A	Pres Fed & State Inc Tax			(84,104)	(27,672)	(56,705)	(362)	(56,343)	(32,727)	(18,244)	(5,276)	(96)	273
38A	Exp Fed & State Inc Tax			32,517	18,861	12,345	3,558	8,787	16,469	(6,891)	(990)	199	1,311
39B	Prop Fed & State Inc Tax			32,517	21,641	9,398	2,474	6,924	14,675	(6,667)	(1,255)	170	1,478
40A	Pres Preliminary Return	(total); BASE		413,739	172,040	237,386	17,816	219,570	183,299	23,176	11,714	1,380	4,313
40B	Prop Preliminary Return	(total); BASE		702,869	294,298	401,272	24,848	376,424	300,820	51,878	21,686	2,040	7,299
41	Total AFUDC			28,498	11,753	16,566	891	15,676	11,642	2,989	984	60	179
42A	**Present Total Return**			442,237	183,793	253,953	18,707	235,246	194,941	26,166	12,699	1,440	4,492
42B	**Proposed Total Return**			731,367	306,051	417,838	25,739	392,100	312,462	54,868	22,670	2,100	7,478
43A	**Pres % Return on Rate Base**			4.44%	4.29%	4.57%	6.12%	4.48%	4.99%	2.63%	3.90%	6.31%	4.18%
43B	**Prop % Return on Rate Base**			7.35%	7.14%	7.52%	8.42%	7.47%	7.99%	5.51%	6.96%	9.21%	6.97%
44A	**Present Common Return**			244,220	98,515	143,350	12,627	130,723	117,163	6,361	6,213	986	2,356
44B	**Proposed Common Return**			533,351	220,773	307,236	19,659	287,577	234,684	35,063	16,184	1,646	5,342
45A	**Pres % Ret on Common Rt Base**			4.67%	4.38%	4.91%	7.87%	4.74%	5.71%	1.22%	3.63%	8.24%	4.18%
45B	**Prop % Ret on Common Rt Base**			10.21%	9.81%	10.53%	12.26%	10.43%	11.44%	6.71%	9.46%	13.74%	9.48%

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Allow For Funds Used During Constr												
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		1,889	785	1,104	50	1,053	790	200	60	4	0
2	Nuclear Fuel	E8760		6,742	2,175	4,543	198	4,344	3,146	833	346	19	24
3	Base Load	E8760		5,923	1,911	3,991	174	3,817	2,764	731	304	17	21
4	Total		419.1,432	14,554	4,871	9,638	423	9,214	6,700	1,764	710	40	45
	Transmission												
5	Gen Step Up Base	E8760		23	7	15	1	15	11	3	1	0	0
6	Gen Step Up Peak	D10S		530	220	310	14	295	222	56	17	1	0
7	Total Gen Step Up			553	228	325	15	310	232	59	18	1	0
8	Bulk Transmission	D10S		1,649	686	964	44	920	690	175	52	3	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
11	Total		419.1,432	2,202	913	1,289	59	1,230	922	233	70	4	0
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		1,701	752	939	50	890	736	179	(25)	0	10
15	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
16	Total Substations			1,701	752	939	50	890	736	179	(25)	0	10
17	Overhead Lines	POL		1,128	729	341	43	298	242	56	0	0	58
18	Underground	PUL		2,048	1,530	510	87	423	345	79	0	0	8
19	Line Transformers	P68		0	0	0	0	0	0	0	0	0	0
20	Services	P69		0	0	0	0	0	0	0	0	0	0
21	Meters	C12WM		249	172	77	26	51	48	2	0	0	1
22	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
23	Total		419.1,432	5,127	3,183	1,867	205	1,661	1,371	316	(25)	0	77
24	**General & Common Plant**	PTD	419.1,432	6,615	2,785	3,773	203	3,570	2,649	676	230	16	57
25	**Total AFUDC**			28,498	11,753	16,566	891	15,676	11,642	2,989	984	60	179
	Labor Allocator												
	Production												
26	Other Prod - Cap	D10S		72,082	29,964	42,118	1,926	40,192	30,147	7,627	2,277	141	0
27	Other Prod - Ene	E8760		201,234	64,922	135,598	5,924	129,675	93,912	24,852	10,332	578	713
28	Total		500 through 557	273,316	94,886	177,716	7,850	169,867	124,059	32,480	12,609	719	713
	Transmission												
29	Stepup Subtrans	P5161A		1,020	355	663	29	633	463	121	47	3	3
30	Bulk Power Subs	D10S		27,250	11,328	15,923	728	15,194	11,397	2,884	861	53	0
31	Total		560 through 571	28,270	11,683	16,585	757	15,828	11,859	3,005	908	56	3
	Distribution												
32	Superv & Eng	ZDTS	580, 590	11,422	7,070	3,711	486	3,225	2,634	583	8	1	641
33	Load Dispatch	D10S	581	625	260	365	17	348	261	66	20	1	0
34	Substation	P61	582, 592	5,265	2,267	2,969	150	2,819	2,224	588	8	0	29
35	Overhead Lines	POL	583, 593	9,351	6,042	2,824	357	2,468	2,005	463	0	0	485
36	Underground Lines	PUL	584, 594	7,955	5,942	1,980	336	1,644	1,339	305	0	0	33
37	Line Transformer	P68	595	1,191	852	335	59	276	260	16	0	0	4
38	Meter	C12WM	586, 597	3,247	2,241	998	338	660	629	30	1	0	7
39	Cust Installation	ZDTS	587	3,518	2,178	1,143	150	993	811	180	3	0	197
40	Street Lighting	P73	585, 596	1,013	0	0	0	0	0	0	0	0	1,013
41	Miscellaneous	OXDTS	588	10,665	6,728	3,302	415	2,887	2,347	539	1	0	635
42	Total			54,251	33,580	17,628	2,307	15,321	12,510	2,768	40	3	3,044
43	**Cust Accounting**	C11WA	901,902,903,904,905	5,662	4,761	883	453	430	422	8	0	0	17
44	**Sales Expense**	C11P10	912	8	5	3	0	3	2	1	0	0	0
45	**Admin & General**	LABOR	920,921,922,923,924,	146,398	58,796	86,072	4,611	81,460	60,193	15,470	5,483	315	1,530
46	**Service & Inform**	C11P10	908, 909	1,310	799	495	61	434	323	79	31	2	15
47	**Labor**			509,215	204,510	299,382	16,040	283,342	209,368	53,810	19,071	1,094	5,322

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	
INTERNAL ALLOCATORS		Intern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	50% Cus, 50% Prod Plt	C11P10	100.00%	61.02%	37.79%	4.66%	33.13%	24.63%	6.01%	2.36%	0.13%	1.18%
2	Peaking Plant Capacity	D10S	100.00%	41.57%	58.43%	2.67%	55.76%	41.82%	10.58%	3.16%	0.20%	0.00%
3	57% Dmd; 43% Energy: Sales & E	D57E43	100.00%	32.26%	67.38%	2.94%	64.44%	46.67%	12.35%	5.13%	0.29%	0.35%
4	40% Dmd; 60% Energy: CIP	D40E60	100.00%	32.26%	67.38%	2.94%	64.44%	46.67%	12.35%	5.13%	0.29%	0.35%
5	20%D10T; 80%D60Sub	T20D80	100.00%	43.69%	55.86%	2.87%	52.99%	42.97%	10.54%	-0.56%	0.04%	0.45%
6	Labor w/o (or w/) A&G	LABOR	100.00%	40.16%	58.79%	3.15%	55.64%	41.12%	10.57%	3.75%	0.21%	1.05%
7	Net Plant In Service	NEPIS	100.00%	43.43%	55.47%	3.07%	52.40%	39.05%	9.92%	3.20%	0.23%	1.10%
8	Dis O&M w/o Sup & Misc	OXDTS	100.00%	63.09%	30.96%	3.89%	27.07%	22.01%	5.06%	0.01%	0.00%	5.95%
9	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	100.00%	38.02%	61.33%	3.09%	58.24%	42.87%	11.06%	4.08%	0.24%	0.65%
10	Production Plant	P10	100.00%	34.20%	65.52%	2.89%	62.63%	45.66%	11.98%	4.72%	0.27%	0.28%
11	Production Plant Wo Nuclear	P10WoN	100.00%	34.72%	65.02%	2.87%	62.15%	45.39%	11.88%	4.61%	0.26%	0.26%
12	Total P51 & P61A	P5161A	100.00%	34.79%	64.95%	2.87%	62.08%	45.35%	11.87%	4.60%	0.26%	0.26%
13	Distribution Plant	P60	100.00%	66.09%	30.64%	3.94%	26.71%	21.97%	4.71%	0.03%	0.00%	3.27%
14	Distr Substn Plant	P61	100.00%	43.06%	56.39%	2.85%	53.54%	42.23%	11.16%	0.15%	0.00%	0.55%
15	Line Transformer Plant	P68	100.00%	71.53%	28.11%	4.95%	23.16%	21.85%	1.31%	0.00%	0.00%	0.36%
16	Services Plant	P69	100.00%	89.82%	10.18%	2.89%	7.29%	7.29%	0.00%	0.00%	0.00%	0.00%
17	Dist Plt Overhead Lines	POL	100.00%	64.61%	30.20%	3.81%	26.39%	21.44%	4.95%	0.00%	0.00%	5.18%
18	Real Est & Property Tax	PT0	100.00%	45.21%	53.72%	3.13%	50.59%	37.86%	9.53%	2.97%	0.22%	1.07%
19	Produc, Trans & Distrib	PTD	100.00%	42.10%	57.04%	3.07%	53.97%	40.04%	10.22%	3.47%	0.24%	0.86%
20	Dist Plt Undground Lines	PUL	100.00%	74.70%	24.89%	4.23%	20.67%	16.83%	3.84%	0.00%	0.00%	0.41%
21	Rate Base (Non-Column)	RTBASE	100.00%	43.07%	55.86%	3.07%	52.78%	39.28%	10.00%	3.28%	0.23%	1.08%
22	Stratified Hydro Baseload	STRATH	100.00%	33.84%	65.87%	2.90%	62.97%	45.85%	12.05%	4.80%	0.27%	0.29%
23	Transmission & Distrib	TD	100.00%	54.72%	43.50%	3.36%	40.14%	31.07%	7.41%	1.48%	0.18%	1.78%
24	Labor Dis w/o Sup & Eng	ZDTS	100.00%	61.90%	32.49%	4.25%	28.24%	23.06%	5.10%	0.07%	0.00%	5.61%

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
INTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
25	Labor w/o A&G	LABOR(S)	362,817	145,714	213,310	11,429	201,882	149,175	38,339	13,588	779	3,792
26	Dis O&M w/o Sup, Cust Install & N	OXDTS	82,990	52,355	25,693	3,226	22,467	18,265	4,196	5	1	4,941
27	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	2,360,162	897,233	1,447,482	72,946	1,374,536	1,011,714	260,936	96,222	5,664	15,446
28	Total P51 & P61A	P5161A	127,076	44,209	82,539	3,647	78,892	57,632	15,084	5,843	333	328
29	Produc, Trans & Distrib	PTD	19,564,680	8,236,780	11,160,243	600,427	10,559,816	7,834,406	1,999,605	679,709	46,096	167,658
30	Transmission & Distrib	TD	7,532,979	4,121,929	3,277,155	253,064	3,024,091	2,340,819	557,990	111,444	13,837	133,895
31	Labor Dis w/o Sup & Eng, Cust In	ZDTS	39,311	24,333	12,774	1,672	11,102	9,065	2,006	29	2	2,205

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2021 Class Cost of Service Study Detail ($000)

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
EXTERNAL ALLOCATORS		Extern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Customers - Ave Monthly	C11	100.00%	87.85%	10.07%	6.43%	3.64%	3.60%	0.04%	0.00%	0.00%	2.08%
2	Cust Acctg Wtg Factor	C11WA	100.00%	84.09%	15.60%	8.00%	7.60%	7.45%	0.13%	0.00%	0.00%	0.31%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	69.03%	30.74%	10.42%	20.32%	19.37%	0.91%	0.03%	0.01%	0.23%
4	Sec & Pri Customers	C61PS	100.00%	89.32%	10.25%	6.54%	3.71%	3.67%	0.04%	0.00%	0.00%	0.43%
5	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	100.00%	95.10%	4.52%	3.86%	0.66%	0.66%	0.01%	0.00%	0.00%	0.38%
6	C62Sec, w/o Ltg & C/I Undergrou	C62NL	100.00%	94.98%	5.02%	3.22%	1.81%	1.81%	0.00%	0.00%	0.00%	0.00%
7	Secondary Customers	C62Sec	100.00%	89.36%	10.22%	6.55%	3.67%	3.67%	0.00%	0.00%	0.00%	0.43%
8	Summer Peak Resp KW	D10S	100.00%	41.57%	58.43%	2.67%	55.76%	41.82%	10.58%	3.16%	0.20%	0.00%
9	Transmission Demand %	D10T	100.00%	51.18%	48.26%	3.92%	44.34%	24.86%	14.11%	4.97%	0.40%	0.56%
10	Winter Peak Resp KW	D10W	100.00%	64.87%	33.76%	5.71%	28.06%	0.68%	19.15%	7.55%	0.68%	1.37%
11	Alternative Production Allocator	1CP	100.00%	41.57%	58.43%	2.67%	55.76%	41.82%	10.58%	3.16%	0.20%	0.00%
12	Sec, Pri & TT, Class Coin kW @ S	D60Sub	100.00%	44.21%	55.22%	2.92%	52.30%	43.25%	10.53%	-1.49%	0.00%	0.56%
13	Sec & Pri, Cl Coin kW (no Min Sy	D61PS	100.00%	38.66%	61.01%	2.39%	58.61%	46.52%	12.09%	0.00%	0.00%	0.33%
14	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	100.00%	76.44%	23.02%	2.62%	20.40%	15.42%	4.98%	0.00%	0.00%	0.55%
15	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	100.00%	75.32%	24.68%	1.97%	22.71%	22.71%	0.00%	0.00%	0.00%	0.00%
16	Sec, Class Coin kW (w/o Min Sys	D62SecL	100.00%	51.22%	48.52%	3.01%	45.51%	45.51%	0.00%	0.00%	0.00%	0.25%
17	Direct Assign Street Lighting	DASL	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
18	On + Off Sales MWH	E8760	100.00%	32.26%	67.38%	2.94%	64.44%	46.67%	12.35%	5.13%	0.29%	0.35%
19	Street Lighting (Dir Assign)	P73	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
20	MWh Sales Excl CIP Exempt	E99XCIP	100.00%	33.03%	66.51%	3.00%	63.513%	48.37%	11.56%	3.27%	0.32%	0.46%
21	Present Rev	R01	100.00%	39.73%	59.38%	3.36%	56.01%	42.31%	9.77%	3.69%	0.25%	0.89%
22	Late Fee Revenue Allocator	LateFee	100.00%	84.95%	14.99%	3.01%	11.98%	10.95%	1.02%	0.01%	0.00%	0.06%
EXTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
23	Customers - B Basis	C10	1,313,257	1,173,030	134,625	85,927	48,698	48,203	473	13	9	5,602
24	Cust - Ave Monthly (C10-Area Lt)	C11	1,339,326	1,176,591	134,820	86,122	48,698	48,203	473	13	9	27,915
25	Mo Cus Wtd By Cus Acct	C11WA	1,399,129	1,176,591	218,247	111,958	106,289	104,300	1,877	69	43	4,291
26	Cust Acctg Wtg Factor	C11WAF	18.51	1.00	17.51	1.30	16.21	2.16	3.97	5.28	4.80	N/A
27	Cust-Ave Mo (C11 w/ Dir Assign S	C12	1,314,123	1,176,591	134,820	86,122	48,698	48,203	473	13	9	2,713
28	Mo Cus Wtd By Mtr Invest	C12WM	167,312,152	115,493,967	51,435,389	17,438,472	33,996,917	32,401,151	1,529,853	44,906	21,007	382,796
29	Meter Invest / Cust Factor	C12WMF	10,138	98	9,899	202	9,697	672	3,236	3,454	2,334	141
30	Sec & Pri Customers	C61PS	1,313,235	1,173,030	134,603	85,927	48,676	48,203	473	0	0	5,602
31	% Served by Primary Single Phase		0.0%	73.13%	0.00%	40.49%	0.00%	12.26%	15.23%	18.18%	22.22%	61.24%
32	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	902,043	857,842	40,770	34,790	5,980	5,908	72	0	0	3,431
33	C62Sec, w/o Ltg & C/I Undergrou	C62NL	1,235,088	1,173,030	62,058	39,756	22,302	22,302	0	0	0	0
34	Secondary Customers	C62Sec	1,312,763	1,173,030	134,130	85,927	48,203	48,203	0	0	0	5,602
35	Summer Peak Resp KW	D10S	36,392	15,128	21,264	972	20,292	15,220	3,851	1,149	71	0
36	Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	5,117,628	4,826,021	392,241	4,433,780	2,486,159	1,411,261	496,809	39,551	56,351
37	Winter Peak Resp KW	D10W	2,352	1,526	794	134	660	16	450	178	16	32
38	Alternative Production Allocator	1CP	36,392	15,128	21,264	972	20,292	15,220	3,851	1,149	71	0
39	Sec, Pri & TT, Class Coin kW @ S	D60Sub	6,222,376	2,751,220	3,436,076	181,950	3,254,126	2,691,417	655,527	(92,818)	0	35,080
40	Sec & Pri, Class Coin kW (w/o Mi	D61PS	5,716,588	2,210,106	3,487,596	136,895	3,350,701	2,659,539	691,162	0	0	18,887
41	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	2,114,519	1,616,260	486,693	55,426	431,267	325,991	105,276	0	0	11,566
42	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	11,194,496	8,432,208	2,762,288	220,523	2,541,765	2,541,765	0	0	0	0
43	Sec, Class Coin kW (w/o Min Sys	D62SecL	10,000,000	5,122,422	4,852,239	301,454	4,550,785	4,550,785	0	0	0	25,339
44	Annual Billing kW	D99	46,482.329	0	46,482	0	46,482	35,818	7,660	2,751	253	0
45	Summer Billing kW	D99S	17,007.448	0	17,007	0	17,007	13,120	2,852	952	83	0
46	Winter Billing kW	D99W	29,474.881	0	29,475	0	29,475	22,698	4,808	1,799	170	0
47	Non-Coinc Pk Second	DN-Sec	14,421,437	8,432,208	5,970,343	476,634	5,493,709	5,493,709	0	0	0	18,887
48	MWh Sales	E99	27,377,491	8,646,889	18,610,322	784,207	17,826,115	12,729,760	3,492,628	1,520,358	83,369	120,281
49	MWh Sales Excl CIP Exempt	E99XCIP	26,177,295	8,646,889	17,410,125	784,062	16,626,063	12,661,153	3,025,173	856,369	83,369	120,281
50	Late Fee Revenue Allocation	LateFee	100.00%	84.95%	14.99%	3.01%	11.98%	10.95%	1.02%	0.01%	0.00%	0.06%

Summary of 2022 Class Cost of Service Study ($000) Page 1 of 1

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UNADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	3,555,766	1,437,878	110,559	1,973,996	33,334
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,665	1,435	52	177	1
[3]	Unadjusted Operating Revenues (line 1 + line 2)	3,557,431	1,439,313	110,611	1,974,172	33,335
[4]	Present Rates (CCOSS page 2, line 2)	3,053,147	1,197,981	103,959	1,723,881	27,326
[5]	Unadjusted Deficiency (line 3 - line 4)	504,284	241,332	6,652	250,291	6,010
[6]	Defic / Pres (line 5 / line 4)	16.5%	20.1%	6.4%	14.5%	22.0%
[7]	**Ratio: Class % / Total %**	**1.00**	**1.22**	**0.39**	**0.88**	**1.33**

COST RESPONSIBILITIES FOR RATE DISCOUNTS

		Total	Residential	Non-Demand	Demand	Street Ltg
		[PROTECTED DATA 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)					
						PROTECTED DATA ENDS]
[12]	Revenue Requirement Change (lines 10 & 11 - lines 8 & 9)	0	(1,996)	780	1,211	6

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[13]	Adjusted Rate Revenue Reqt (line 1 + line 12)	3,555,766	1,435,881	111,340	1,975,206	33,339
[14]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,665	1,435	52	177	1
[15]	Adjusted Operating Revenues (line 13 + line 14)	3,557,431	1,437,316	111,392	1,975,383	33,341
[16]	Present Rates (line 4)	3,053,147	1,197,981	103,959	1,723,881	27,326
[17]	Adjusted Deficiency (line 15 - line 16)	504,284	239,336	7,432	251,501	6,015
[18]	**Defic / Pres Rates (line 17 / line 16)**	**16.5%**	**20.0%**	**7.1%**	**14.6%**	**22.0%**
[19]	**Ratio: Class % / Total %**	**1.00**	**1.21**	**0.43**	**0.88**	**1.33**

PROPOSED REVENUE RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[20]	Proposed Rates (CCOSS page 3, line 3)	3,555,766	1,415,538	116,207	1,991,439	32,582
[21]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,665	1,435	52	177	1
[22]	Proposed Operating Revenues (line 20 + line 21)	3,557,431	1,416,974	116,258	1,991,616	32,583
[23]	Proposed Increase (line 22 - line 16)	504,284	218,993	12,299	267,735	5,258
[24]	Difference / Pres (line 23 / line 16)	16.5%	18.3%	11.8%	15.5%	19.2%
[25]	**Ratio: Class % / Total %**	**1.00**	**1.11**	**0.72**	**0.94**	**1.16**

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

	Rate Base		1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Plant In Service	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Production		12,244,456	4,157,810	8,052,096	354,727	7,697,369	5,626,947	1,423,395	579,713	67,314	34,551
2	Transmission		3,592,979	1,508,741	2,083,890	92,959	1,990,931	1,492,421	363,163	114,372	20,975	348
3	Distribution		4,371,330	2,888,851	1,341,725	173,108	1,168,617	965,413	202,111	1,054	38	140,754
4	General		2,043,507	865,121	1,160,624	62,775	1,097,849	817,532	201,094	70,292	8,932	17,762
5	Common		0	0	0	0	0	0	0	0	0	0
6	Total Plant In Service		22,252,272	9,420,524	12,638,334	683,569	11,954,765	8,902,313	2,189,763	765,432	97,258	193,414
7	Production		7,119,351	2,412,356	4,686,733	206,442	4,480,291	3,274,449	828,555	338,041	39,246	20,261
8	Transmission		835,805	351,869	483,895	21,565	462,330	346,357	84,203	26,364	5,406	42
9	Distribution		1,569,707	1,066,596	468,172	63,938	404,234	336,638	66,914	659	24	34,938
10	General		1,041,646	440,982	591,610	31,998	559,612	416,724	102,505	35,830	4,553	9,054
11	Common		0	0	0	0	0	0	0	0	0	0
12	Total Depreciation Reserve		10,566,509	4,271,803	6,230,411	323,943	5,906,467	4,374,168	1,082,177	400,895	49,228	64,295
13	**Net Plant In Service**		11,685,763	5,148,720	6,407,923	359,625	6,048,298	4,528,145	1,107,586	364,537	48,030	129,119
14	Deducts: Accum Defer Inc Tax		2,147,245	925,213	1,200,888	65,134	1,135,755	849,401	207,905	69,153	9,297	21,144
15	Constr Work In Progress		417,943	171,702	243,990	12,501	231,488	172,139	42,691	14,872	1,787	2,251
16	Fuel Inventory		84,026	26,692	57,035	2,503	54,532	39,598	10,106	4,328	500	299
17	Materials & Supplies		152,207	55,094	96,445	4,481	91,964	67,526	16,968	6,679	791	668
18	Prepayments		106,071	46,735	58,165	3,264	54,900	41,102	10,054	3,309	436	1,172
19	Non-Plant & Work Cash		(31,010)	(21,931)	(8,706)	(1,098)	(7,608)	(6,462)	(1,263)	170	(53)	(372)
20	Total Additions		729,237	278,291	446,928	21,651	425,276	313,903	78,554	29,358	3,461	4,018
21	**Rate Base**		10,267,755	4,501,799	5,653,963	316,143	5,337,819	3,992,647	978,236	324,742	42,194	111,994
	Income Statement											
22A	**Tot Oper Rev - Pres**		3,616,971	1,405,314	2,182,838	120,019	2,062,819	1,554,713	352,403	136,837	18,865	28,820
22B	**Tot Oper Rev - Prop**		4,121,256	1,624,307	2,462,871	132,318	2,330,553	1,755,901	399,711	153,696	21,245	34,078
23	Oper & Maint		2,427,824	916,489	1,495,190	74,464	1,420,726	1,048,912	260,742	99,159	11,913	16,145
24	Book Depr + IRS Int		778,372	323,996	445,950	23,915	422,034	313,729	77,269	27,618	3,419	8,426
25	Payroll, Rl Est & Prop Tax		229,454	102,611	124,393	7,147	117,246	87,921	21,409	7,005	912	2,451
26	Deferred Inc Tax & Net ITC		(146,787)	(66,837)	(77,809)	(4,481)	(73,328)	(55,107)	(13,344)	(4,313)	(564)	(2,141)
27A	Present Income Tax		(41,137)	(18,993)	(22,285)	1,278	(23,563)	(9,411)	(11,815)	(2,642)	304	141
27B	Proposed Income Tax		103,804	43,950	58,202	4,813	53,389	48,415	1,783	2,204	988	1,652
28	Allow Funds Dur Const		25,065	10,416	14,509	769	13,740	10,242	2,526	867	105	140
29A	**Present Return**		394,310	158,464	231,909	18,465	213,444	178,911	20,668	10,878	2,986	3,938
29B	**Proposed Return**		753,653	314,514	431,455	27,229	404,226	322,274	54,379	22,892	4,682	7,684
30A	**Pres Ret on Rt Base**		3.84%	3.52%	4.10%	5.84%	4.00%	4.48%	2.11%	3.35%	7.08%	3.52%
30B	**Prop Ret on Rt Base**		**7.34%**	6.99%	7.63%	8.61%	7.57%	8.07%	5.56%	7.05%	11.10%	6.86%
31A	**Pres Ret on Common**		3.54%	2.93%	4.04%	7.35%	3.85%	4.76%	0.25%	2.61%	9.71%	2.93%
31B	**Prop Ret on Common**		**10.21%**	9.54%	10.76%	12.63%	10.65%	11.60%	6.82%	9.66%	17.36%	9.30%

2022 Class Cost of Service Study Detail ($000)

PRES vs Equal Rev Reqts

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**UnAdj Equal Rev Reqt @ 7.34%**		**3,555,766**	**1,437,878**	**2,084,555**	**110,559**	**1,973,996**	**1,465,196**	**361,681**	**130,911**	**16,208**	**33,334**
2	**Present Revenue**		**3,053,147**	**1,197,981**	**1,827,841**	**103,959**	**1,723,881**	**1,305,159**	**289,940**	**112,730**	**16,053**	**27,326**
3	**UnAdj Revenue Deficiency**		**502,619**	**239,897**	**256,714**	**6,600**	**250,114**	**160,038**	**71,741**	**18,181**	**155**	**6,008**
4	**UnAdj Deficiency / Present**		**16.46%**	**20.03%**	**14.04%**	**6.35%**	**14.51%**	**12.26%**	**24.74%**	**16.13%**	**0.96%**	**21.99%**
			[PROTECTED DATA 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**										
												PROTECTED DATA ENDS]
9	**Revenue Requirement Shift**		**0**	**(1,996)**	**1,991**	**780**	**1,211**	**7,677**	**(3,541)**	**(2,881)**	**(44)**	**6**
10	**Adj Equal Rev Reqt (Rows 1+9)**		**3,555,766**	**1,435,881**	**2,086,546**	**111,340**	**1,975,206**	**1,472,873**	**358,141**	**128,029**	**16,163**	**33,339**
11	**Adj Rev Defic vs Pres Rev (Row 2)**		**502,619**	**237,901**	**258,705**	**7,380**	**251,325**	**167,715**	**68,200**	**15,299**	**111**	**6,014**
12	**Adj Deficiency / Adj Present**		**16.46%**	**19.86%**	**14.15%**	**7.10%**	**14.58%**	**12.85%**	**23.52%**	**13.57%**	**0.69%**	**22.01%**
	Equal Customer Classification											
13	Min Sys & Service Drop		264,086	215,536	24,103	14,310	9,793	9,591	196	5	2	24,447
14	Energy Services		53,801	45,298	8,294	4,252	4,042	3,967	71	3	2	208
15	Total Customer **(Cusco)**		317,887	260,835	32,397	18,562	13,835	13,558	266	7	4	24,655
16	Ave Monthly Customers		1,349,008	1,186,060	134,925	86,190	48,735	48,240	472	13	9	28,023
17	Svc Drop Reqt	$ / Mo / Cust	$16.31	$15.14	$14.89	$13.84	$16.75	$16.57	$34.49	$29.98	$20.22	$72.70
18	Ener Svcs Reqt	$ / Mo / Cust	$3.32	$3.18	$5.12	$4.11	$6.91	$6.85	$12.49	$16.55	$15.21	$0.62
19	Total Reqt	$ / Mo / Cust	$19.64	$18.33	$20.01	$17.95	$23.66	$23.42	$46.97	$46.53	$35.43	$73.32
	Equal Energy Classification											
20	On Peak Rev Reqt		814,197	249,644	563,130	25,791	537,339	396,380	97,914	38,276	4,769	1,424
21	Off Peak Rev Reqt		828,506	271,733	552,210	23,206	529,004	380,904	98,895	44,084	5,121	4,563
22	Total Ener Rev Reqt		1,642,703	521,377	1,115,340	48,997	1,066,343	777,284	196,809	82,360	9,890	5,987
23	Annual MWh Sales		27,524,194.975	8,554,019	18,848,849	797,589	18,051,260	12,923,759	3,418,503	1,533,254	175,744	121,327
24	On Pk Reqt	Mills / kWh	29.581	29.184	29.876	32.337	29.767	30.671	28.642	24.964	27.134	11.733
25	Off Pk Reqt	Mills / kWh	30.101	31.767	29.297	29.095	29.306	29.473	28.929	28.752	29.140	37.613
26	Total Reqt	Mills / kWh	59.682	60.951	59.173	61.432	59.073	60.144	57.572	53.716	56.274	49.346
	Equal Demand Classification											
27	Energy-Related Prod		428,545	140,144	287,018	12,608	274,410	199,860	50,792	21,290	2,468	1,384
28	Capacity-Related Summer Peak Prod		309,969	131,098	178,870	8,007	170,864	128,677	31,287	9,737	1,163	0
29	Capacity-Related Winter Peak Prod		92,484	39,115	53,369	2,389	50,980	38,393	9,335	2,905	347	0
30	Total Capacity-Related Prod		402,453	170,214	232,239	10,396	221,844	167,069	40,622	12,642	1,510	0
31	Total Production		830,999	310,358	519,257	23,004	496,253	366,929	91,414	33,932	3,978	1,384
32	Transmission **(Transco)**		463,510	195,805	267,705	11,955	255,750	192,177	46,702	14,535	2,336	0
33	Primary Dist Subs		87,306	37,708	49,106	2,530	46,577	37,055	9,445	76	0	492
34	Prim Dist Lines		182,723	94,777	87,193	4,628	82,565	65,521	17,044	0	0	753
35	Second Dist, Trans		30,637	17,018	13,556	883	12,673	12,673	0	0	0	63
36	Total Distribution **(Disco)**		300,667	149,503	149,856	8,041	141,814	115,249	26,489	76	0	1,308
37	Total Demand Rev Reqt		1,595,176	655,667	936,818	43,000	893,818	674,355	164,606	48,543	6,314	2,692
38	Annual Billing kW		47,159,100	0	47,159,100	0	47,159,100	36,365,310	7,511,248	2,775,908	506,635	0
39	Base Rev Reqt	$ / kW	$0.00	$0.00	$6.09	$0.00	$5.82	$5.50	$6.76	$7.67	$4.87	$0.00
40	Summer Rev Reqt	$ / kW	$0.00	$0.00	$3.79	$0.00	$3.62	$3.54	$4.17	$3.51	$2.30	$0.00
41	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.13	$0.00	$1.08	$1.06	$1.24	$1.05	$0.68	$0.00
42	Prod Rev Reqt	$ / kW	$0.00	$0.00	$11.01	$0.00	$10.52	$10.09	$12.17	$12.22	$7.85	$0.00
43	Tran Rev Reqt	$ / kW	$0.00	$0.00	$5.68	$0.00	$5.42	$5.28	$6.22	$5.24	$4.61	$0.00
44	Dist Rev Reqt	$ / kW	$0.00	$0.00	$3.18	$0.00	$3.01	$3.17	$3.53	$0.03	$0.00	$0.00
45	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$19.87	$0.00	$18.95	$18.54	$21.91	$17.49	$12.46	$0.00
46	Tot Dmd Rev Reqt	Mills / kWh	57.955	76.650	49.702	53.912	49.516	52.179	48.151	31.660	35.926	22.187
47	Summer Billing kW		17,322,925	0	17,322,925	0	17,322,925	13,365,101	2,807,854	961,102	188,868	0
48	Winter Billing kW		29,836,175	0	29,836,175	0	29,836,175	23,000,209	4,703,394	1,814,806	317,767	0
49	Tot Summer Reqt	$ / kW	$0.00	$0.00	$25.27	$0.00	$24.11	$23.58	$27.65	$23.06	$15.64	$0.00
50	Tot Winter Reqt	$ / kW	$0.00	$0.00	$16.73	$0.00	$15.96	$15.62	$18.49	$14.53	$10.57	$0.00
51	Energy + Production **(Genco)**		2,473,702	831,734	1,634,597	72,001	1,562,596	1,144,213	288,224	116,292	13,868	7,371

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Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

	PROP vs Equal Rev Reqts		1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**Proposed Ret On Rt Base**		**7.34%**	**6.99%**	**7.63%**	**8.61%**	**7.57%**	**8.07%**	**5.56%**	**7.05%**	**11.10%**	**6.86%**
2	**UnAdj Equalized Rev Reqt**		**3,555,766**	**1,437,878**	**2,084,555**	**110,559**	**1,973,996**	**1,465,196**	**361,681**	**130,911**	**16,208**	**33,334**
3	**Proposed Revenue**		**3,555,766**	**1,415,538**	**2,107,646**	**116,207**	**1,991,439**	**1,506,193**	**337,229**	**129,586**	**18,432**	**32,582**
4	**UnAdj Revenue Deficiency**		**0**	**22,339**	**(23,091)**	**(5,647)**	**(17,444)**	**(40,996)**	**24,452**	**1,325**	**(2,224)**	**752**
5	**UnAdj Deficiency / Proposed**		**0.00%**	**1.58%**	**-1.10%**	**-4.86%**	**-0.88%**	**-2.72%**	**7.25%**	**1%**	**-12%**	**2.31%**
			[PROTECTED DATA 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**										
												PROTECTED DATA ENDS]
10	**Revenue Requirement Shift**		**0**	**4,720**	**(4,727)**	**549**	**(5,276)**	**3,206**	**(5,020)**	**(3,370)**	**(92)**	**7**
11	**Adj Equal Rev (Rows 2+10)**		**3,555,766**	**1,442,598**	**2,079,828**	**111,108**	**1,968,720**	**1,468,402**	**356,661**	**127,541**	**16,116**	**33,341**
12	**Adj Rev Defic vs Prop Rev (Row 3)**		**0**	**27,059**	**(27,818)**	**(5,098)**	**(22,720)**	**(37,791)**	**19,432**	**(2,045)**	**(2,316)**	**759**
13	**Adj Deficiency / Adj Prop**		**0.00%**	**1.91%**	**-1.32%**	**-4.39%**	**-1.14%**	**-2.51%**	**5.76%**	**-1.58%**	**-12.56%**	**2.33%**
	Prop Customer Component											
14	Min Sys & Service Drop		259,135	209,761	25,576	15,405	10,171	9,980	184	5	2	23,798
15	Energy Services		53,802	45,300	8,294	4,252	4,042	3,967	71	3	2	208
16	Total Customer **(Cusco)**		312,937	255,061	33,870	19,657	14,213	13,947	255	7	4	24,007
17	Ave Monthly Customers		1,349,008	1,186,060	134,925	86,190	48,735	48,240	472	13	9	28,023
18	Svc Drop Reqt	$ / Mo / Cust	$16.01	$14.74	$15.80	$14.89	$17.39	$17.24	$32.46	$30.10	$22.98	$70.77
19	Ener Svcs Reqt	$ / Mo / Cust	$3.32	$3.18	$5.12	$4.11	$6.91	$6.85	$12.49	$16.55	$15.21	$0.62
20	Total Reqt	$ / Mo / Cust	$19.33	$17.92	$20.92	$19.01	$24.30	$24.09	$44.95	$46.65	$38.19	$71.39
	Prop Energy Component											
21	On Peak Rev Reqt		814,043	249,480	563,140	25,821	537,319	396,591	97,689	38,251	4,787	1,423
22	Off Peak Rev Reqt		828,316	271,553	552,203	23,233	528,970	381,106	98,668	44,055	5,141	4,560
23	Total Ener Rev Reqt		1,642,359	521,034	1,115,343	49,054	1,066,289	777,697	196,356	82,307	9,928	5,983
24	Annual MWh Sales		27,524,195	8,554,019	18,848,849	797,589	18,051,260	12,923,759	3,418,503	1,533,254	175,744	121,327
25	On Pk Reqt	Mills / kWh	29.576	29.165	29.877	32.374	29.766	30.687	28.576	24.948	27.240	11.726
26	Off Pk Reqt	Mills / kWh	30.094	31.746	29.296	29.129	29.304	29.489	28.863	28.733	29.254	37.587
27	Total Reqt	Mills / kWh	59.670	60.911	59.173	61.503	59.070	60.176	57.439	53.681	56.494	49.313
	Prop Demand Component											
28	Energy-Related Prod		434,553	134,806	298,426	14,860	283,566	220,540	38,759	20,505	3,763	1,320
29	Capacity-Related Summer Peak Prod		310,759	129,631	181,128	8,423	172,705	132,570	29,161	9,639	1,336	0
30	Capacity-Related Winter Peak Prod		92,720	38,677	54,043	2,513	51,529	39,554	8,701	2,876	399	0
31	Total Capacity-Related Prod		403,479	168,308	235,171	10,936	224,235	172,124	37,861	12,515	1,734	0
32	Total Production		838,032	303,115	533,597	25,796	507,800	392,664	76,620	33,019	5,497	1,320
33	Transmission **(Transco)**		463,356	190,832	272,524	13,003	259,521	201,554	40,771	14,195	3,002	0
34	Primary Dist Subs		87,120	36,661	49,981	2,772	47,210	39,024	8,128	58	0	478
35	Prim Dist Lines		181,298	92,370	88,195	4,973	83,222	68,123	15,100	0	0	733
36	Second Dist, Trans		30,664	16,466	14,137	952	13,185	13,185	0	0	0	61
37	Total Distribution **(Disco)**		299,082	145,498	152,313	8,697	143,616	120,331	23,228	58	0	1,272
38	Total Demand Rev Reqt		1,600,470	639,444	958,434	47,496	910,938	714,549	140,618	47,271	8,499	2,592
39	Annual Billing kW		47,159,100	0	47,159,100	0	47,159,100	36,365,310	7,511,248	2,775,908	506,635	0
40	Base Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$6.01	$6.06	$5.16	$7.39	$7.43	$0.00
41	Summer Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$3.66	$3.65	$3.88	$3.47	$2.64	$0.00
42	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$1.09	$1.09	$1.16	$1.04	$0.79	$0.00
43	Prod Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$10.77	$10.80	$10.20	$11.89	$10.85	$0.00
44	Tran Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$5.50	$5.54	$5.43	$5.11	$5.93	$0.00
45	Dist Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$3.05	$3.31	$3.09	$0.02	$0.00	$0.00
46	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$19.32	$19.65	$18.72	$17.03	$16.78	$0.00
47	Tot Dmd Rev Reqt	Mills / kWh	58.148	74.754	50.848	59.549	50.464	55.290	41.134	30.831	48.361	21.364
48	Summer Billing kW		17,322,925	0	17,322,925	0	17,322,925	13,365,101	2,807,854	961,102	188,868	0
49	Winter Billing kW		29,836,175	0	29,836,175	0	29,836,175	23,000,209	4,703,394	1,814,806	317,767	0
50	Tot Summer Reqt	$ / kW	$0.00	$0.00	$25.79	$0.00	$24.53	$24.84	$24.07	$22.55	$20.42	$0.00
51	Tot Winter Reqt	$ / kW	$0.00	$0.00	$17.15	$0.00	$16.29	$16.64	$15.53	$14.11	$14.61	$0.00
52	Energy + Production **(Genco)**		2,480,391	824,148	1,648,939	74,850	1,574,089	1,170,361	272,976	115,326	15,425	7,303
53	Prop Rev - Pres Rev (Pg 2)		502,619	217,558	279,805	12,247	267,558	201,034	47,289	16,856	2,379	5,256
54	Difference / Present		16.46%	18.16%	15.31%	11.78%	15.52%	15.40%	16.31%	14.95%	14.82%	19.24%

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Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

Original Plant in Service

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Summer Peak	D10S		1,946,423	824,849	1,121,574	50,264	1,071,310	806,840	196,152	61,030	7,287	0
2	WInter Peak	D10S		580,747	246,107	334,640	14,997	319,643	240,734	58,525	18,209	2,174	0
3	Total Peak	D10S		2,527,170	1,070,956	1,456,214	65,261	1,390,953	1,047,574	254,678	79,240	9,461	0
4	Base Load	E8760		7,086,005	2,250,984	4,809,826	211,083	4,598,742	3,339,354	852,248	364,954	42,187	25,195
5	Nuclear Fuel	E8760		2,631,281	835,869	1,786,056	78,383	1,707,674	1,240,019	316,469	135,520	15,666	9,356
6	Total	26.29%	120, 310-346	12,244,456	4,157,810	8,052,096	354,727	7,697,369	5,626,947	1,423,395	579,713	67,314	34,551
	Transmission												
7	Gen Step Up Base	E8760		97,877	31,092	66,437	2,916	63,521	46,126	11,772	5,041	583	348
8	Gen Step Up Peak	D10S		36,912	15,643	21,270	953	20,317	15,301	3,720	1,157	138	0
9	Total Gen Step Up			134,790	46,735	87,707	3,869	83,838	61,427	15,492	6,198	721	348
10	Bulk Transmission	D10S		3,449,944	1,462,006	1,987,937	89,090	1,898,847	1,430,087	347,671	108,173	12,916	0
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		8,246	0	8,246	0	8,246	907	0	0	7,338	0
13	Total		350-359	3,592,979	1,508,741	2,083,890	92,959	1,990,931	1,492,421	363,163	114,372	20,975	348
	Distribution:												
	Substations												
14	Generat Step Up	STRATH		3,046	1,022	2,015	89	1,926	1,406	356	146	17	9
15	Bulk Transmission	D10S		1,812	768	1,044	47	997	751	183	57	7	0
16	Distrib Function	D60Sub		740,819	328,633	407,910	22,008	385,903	321,605	75,434	(11,136)	0	4,275
17	Direct Assign	Dir Assign		19,104,617	0	19,105	0	19,105	409	6,737	11,958	0	0
18	Total		360-363	764,782	330,424	430,074	22,143	407,931	324,172	82,710	1,025	24	4,284
	Overhead Lines												
19	Primary Capacity 1 Phase	D61PS1Ph		172,845	132,123	39,766	4,634	35,133	26,783	8,349	0	0	956
20	Primary Capacity Multi Phase	D61PS		371,888	143,873	226,771	9,114	217,657	174,005	43,653	0	0	1,243
21	Primary Customer 1 Phase	C61PS1Ph		92,723	88,205	4,162	3,552	610	603	7	0	0	357
22	Primary Customer Multi Phase	C61PS		199,500	178,324	20,315	12,969	7,346	7,275	71	0	0	861
23	Total Primary			836,957	542,525	291,015	30,268	260,747	208,666	52,081	0	0	3,417
24	Second Capacity	D62SecL		42,537	21,686	20,742	1,312	19,430	19,430	0	0	0	109
25	Second Customer	C62Sec		153,041	136,844	15,535	9,952	5,583	5,583	0	0	0	661
26	Total Secondary			195,577	158,531	36,277	11,264	25,013	25,013	0	0	0	769
27	Street Lighting	DASL		52,077	0	0	0	0	0	0	0	0	52,077
28	Total		364,365	1,084,612	701,055	327,292	41,533	285,760	233,679	52,081	0	0	56,264
	Underground Lines												
29	Primary Capacity 1 Phase	D61PS1Ph		281,098	214,871	64,672	7,536	57,136	43,557	13,579	0	0	1,555
30	Primary Capacity Multi Phase	D61PS		404,012	156,301	246,360	9,901	236,459	189,035	47,423	0	0	1,351
31	Primary Customer 1 Phase	C61PS1Ph		319,449	303,881	14,339	12,236	2,103	2,078	25	0	0	1,229
32	Primary Customer Multi Phase	C61PS		459,132	410,396	46,754	29,847	16,907	16,743	164	0	0	1,982
33	Total Primary			1,463,692	1,085,450	372,125	59,520	312,605	251,414	61,191	0	0	6,117
34	Second Capacity	D62SecL		47,088	24,007	22,961	1,452	21,509	21,509	0	0	0	120
35	Second Customer	C62Sec		132,377	118,368	13,438	8,609	4,829	4,829	0	0	0	572
36	Total Secondary			179,465	142,374	36,399	10,061	26,338	26,338	0	0	0	692
37	Street Lighting	DASL		0	0	0	0	0	0	0	0	0	0
38	Total		366,367	1,643,157	1,227,824	408,524	69,581	338,943	277,752	61,191	0	0	6,808
	Line Transformers												
39	Primary	D61PS		43,861	16,968	26,746	1,075	25,671	20,522	5,148	0	0	147
40	Second Capacity	D62SecL		130,944	66,758	63,852	4,039	59,813	59,813	0	0	0	334
41	Second Customer	C62Sec		229,952	205,616	23,343	14,954	8,389	8,389	0	0	0	993
42	Total		368	404,756	289,343	113,940	20,068	93,872	88,724	5,148	0	0	1,474
	Services												
43	Second Capacity	D62NLL		70,993	53,291	17,702	1,439	16,263	16,263	0	0	0	0
44	Second Customer	C62NL		223,309	212,165	11,144	7,139	4,005	4,005	0	0	0	0
43	Total Services	C62NL	369	294,302	265,456	28,846	8,578	20,268	20,268	0	0	0	0
44	Meters	C12WM	370	108,044	74,750	33,048	11,205	21,843	20,819	982	29	13	246
45	Street Lighting	Dir Assign	373	71,678	0	0	0	0	0	0	0	0	71,678
46	**Total Distribution**			4,371,330	2,888,851	1,341,725	173,108	1,168,617	965,413	202,111	1,054	38	140,754
47	**General & Common Plant**	PTD	303, 389-399	2,043,507	865,121	1,160,624	62,775	1,097,849	817,532	201,094	70,292	8,932	17,762
48	Prelim Elec Plant			22,252,272	9,420,524	12,638,334	683,569	11,954,765	8,902,313	2,189,763	765,432	97,258	193,414
49	TBT Investment	NEPIS		0	0	0	0	0	0	0	0	0	0
50	**Elec Plant in Serv**			22,252,272	9,420,524	12,638,334	683,569	11,954,765	8,902,313	2,189,763	765,432	97,258	193,414

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

Docket No. E002/GR-20-723
Exhibit___(MAP), Schedule 6

Accum Deprec; Net Plant

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		1,420,960	602,170	818,790	36,695	782,096	589,023	143,199	44,554	5,320	0
2	Decom Int Peaking	D10S		0	0	0	0	0	0	0	0	0	0
3	Decom Int Baseload	E8760		0	0	0	0	0	0	0	0	0	0
4	Nuclear Fuel	E8760		2,464,560	782,907	1,672,890	73,416	1,599,473	1,161,450	296,417	126,933	14,673	8,763
5	Base Load	E8760		3,233,830	1,027,279	2,195,053	96,332	2,098,722	1,523,976	388,939	166,553	19,253	11,498
6	Total		108,111,115,120.5	7,119,351	2,412,356	4,686,733	206,442	4,480,291	3,274,449	828,555	338,041	39,246	20,261
	Transmission												
7	Gen Step Up Base	E8760		11,780	3,742	7,996	351	7,645	5,551	1,417	607	70	42
8	Gen Step Up Peak	D10S		15,177	6,432	8,745	392	8,353	6,291	1,529	476	57	0
9	Total Gen Step Up			26,957	10,174	16,741	743	15,998	11,842	2,946	1,083	127	42
10	Bulk Transmission	D10S		806,309	341,695	464,614	20,822	443,792	334,235	81,256	25,282	3,019	0
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		2,540	0	2,540	0	2,540	280	0	0	2,261	0
13	Total		108,111,115,120.5	835,805	351,869	483,895	21,565	462,330	346,357	84,203	26,364	5,406	42
	Distribution												
14	Generat Step Up	STRATH		2,322	779	1,536	68	1,468	1,072	272	112	13	7
15	Bulk Transmission	D10S		644	273	371	17	354	267	65	20	2	0
16	Distrib Function	D60Sub		241,073	106,942	132,740	7,162	125,578	104,655	24,547	(3,624)	0	1,391
17	Direct Assign	Dir Assign		6,603	0	6,603	0	6,603	141	2,329	4,133	0	0
18	Total Substations			250,642	107,994	141,250	7,246	134,004	106,135	27,212	641	15	1,398
19	Overhead Lines	POL		375,160	242,490	113,208	14,366	98,842	80,828	18,014	0	0	19,461
20	Underground	PUL		505,779	377,936	125,748	21,418	104,330	85,495	18,835	0	0	2,096
21	Line Transformers	P68		178,012	127,253	50,111	8,826	41,285	39,021	2,264	0	0	648
22	Services	P69		184,185	166,132	18,053	5,368	12,685	12,685	0	0	0	0
23	Meters	C12WM		64,739	44,790	19,802	6,714	13,088	12,475	588	17	8	147
24	Street Lighting	P73		11,188	0	0	0	0	0	0	0	0	11,188
25	Total		108,111,115,120.5	1,569,707	1,066,596	468,172	63,938	404,234	336,638	66,914	659	24	34,938
26	**General & CommonPlant**	PTD	108,111,115,120.5	1,041,646	440,982	591,610	31,998	559,612	416,724	102,505	35,830	4,553	9,054
27	**Total Accum Depr**			10,566,509	4,271,803	6,230,411	323,943	5,906,467	4,374,168	1,082,177	400,895	49,228	64,295
28	**Net Elec Plant**			11,685,763	5,148,720	6,407,923	359,625	6,048,298	4,528,145	1,107,586	364,537	48,030	129,119
29	**Net Plant w/ TBT**			11,685,763	5,148,720	6,407,923	359,625	6,048,298	4,528,145	1,107,586	364,537	48,030	129,119

Subtractions: Accum Defer Inc Tax

				MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
	Production												
30	Peaking Plant	D10S		263,355	111,604	151,751	6,801	144,950	109,167	26,540	8,258	986	0
31	Base Load	E8760		967,636	307,385	656,811	28,825	627,986	456,009	116,380	49,837	5,761	3,441
32	Nuclear Fuel	E8760		(7,000)	(2,224)	(4,751)	(209)	(4,543)	(3,299)	(842)	(361)	(42)	(25)
33	Total		190,281,282,283	1,223,991	416,765	803,810	35,417	768,393	561,877	142,077	57,734	6,705	3,416
	Transmission												
34	Gen Step Up Base	E8760		16,920	5,375	11,485	504	10,981	7,974	2,035	871	101	60
35	Gen Step Up Peak	D10S		4,455	1,888	2,567	115	2,452	1,847	449	140	17	0
36	Total Gen Step Up			21,375	7,263	14,052	619	13,433	9,820	2,484	1,011	117	60
37	Bulk Transmission	D10S		727,093	308,125	418,968	18,776	400,192	301,398	73,273	22,798	2,722	0
38	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
39	Direct Assign	Dir Assign		1,591	0	1,591	0	1,591	175	0	0	1,416	0
40	Total		281,282,283	750,059	315,388	434,611	19,395	415,215	311,393	75,757	23,809	4,255	60
	Distribution												
41	Generat Step Up	STRATH		298	100	197	9	189	138	35	14	2	1
42	Bulk Transmission	D10S		244	103	141	6	134	101	25	8	1	0
43	Distrib Function	D60Sub		110,144	48,861	60,648	3,272	57,375	47,816	11,215	(1,656)	0	636
44	Direct Assign	Dir Assign		2,487	0	2,487	0	2,487	53	877	1,557	0	0
45	Total Substations			113,173	49,064	63,473	3,287	60,185	48,108	12,152	(77)	3	636
46	Overhead Lines	POL		150,315	97,159	45,359	5,756	39,603	32,385	7,218	0	0	7,798
47	Underground	PUL		231,511	172,993	57,559	9,804	47,755	39,134	8,621	0	0	959
48	Line Transformers	P68		55,454	39,641	15,610	2,749	12,861	12,156	705	0	0	202
49	Services	P69		16,755	15,113	1,642	488	1,154	1,154	0	0	0	0
50	Meters	C12WM		10,854	7,509	3,320	1,126	2,194	2,091	99	3	1	25
51	Street Lighting	P73		13,025	0	0	0	0	0	0	0	0	13,025
52	Total		281,282,283	591,087	381,479	186,963	23,210	163,753	135,028	28,795	(74)	4	22,645
53	**General & Common Plant**	PTD	281,282,283	142,120	60,167	80,718	4,366	76,352	56,857	13,985	4,889	621	1,235
54	**Total Deferred Tax**			2,707,257	1,173,799	1,506,102	82,388	1,423,713	1,065,155	260,615	86,357	11,585	27,356
55	Net Operating Loss (NOL) Carry F	NEPIS		(597,425)	(263,224)	(327,600)	(18,386)	(309,214)	(231,498)	(56,624)	(18,637)	(2,455)	(6,601)
56	Non-Plant Related	LABOR		37,413	14,638	22,387	1,131	21,256	15,743	3,914	1,432	167	389
57	**Accum Def W/ Adj**			2,147,245	925,213	1,200,888	65,134	1,135,755	849,401	207,905	69,153	9,297	21,144

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NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

Additions: CWIP, Etc; Rate Base

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		39,985	16,945	23,041	1,033	22,008	16,575	4,030	1,254	150	0
2	Base Load	E8760		66,031	20,976	44,820	1,967	42,853	31,118	7,942	3,401	393	235
3	Nuclear Fuel	E8760		93,427	29,679	63,416	2,783	60,633	44,029	11,237	4,812	556	332
4	Total		107	199,444	67,599	131,277	5,783	125,495	91,721	23,208	9,466	1,099	567
	Transmission												
5	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10S		0	0	0	0	0	0	0	0	0	0
7	Total Gen Step Up			0	0	0	0	0	0	0	0	0	0
8	Bulk Transmission	D10S		77,729	32,940	44,789	2,007	42,782	32,221	7,833	2,437	291	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
11	Total		107	77,729	32,940	44,789	2,007	42,782	32,221	7,833	2,437	291	0
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		10,497	4,657	5,780	312	5,468	4,557	1,069	(158)	0	61
15	Direct Assign	Dir Assign		1	0	1	0	1	0	0	0	0	0
16	Total Substations			10,498	4,657	5,781	312	5,469	4,557	1,069	(157)	0	61
17	Overhead Lines	POL		14,035	9,072	4,235	537	3,698	3,024	674	0	0	728
18	Underground	PUL		26,149	19,539	6,501	1,107	5,394	4,420	974	0	0	108
19	Line Transformers	P68		(670)	(479)	(189)	(33)	(155)	(147)	(9)	0	0	(2)
20	Services	P69		(101)	(91)	(10)	(3)	(7)	(7)	0	0	0	0
21	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
23	Total		107	49,910	32,697	16,318	1,920	14,398	11,847	2,708	(157)	0	895
24	**General & Common Plant**	PTD	107	90,860	38,466	51,604	2,791	48,813	36,350	8,941	3,125	397	790
25	**Total CWIP**			417,943	171,702	243,990	12,501	231,488	172,139	42,691	14,872	1,787	2,251
26	Fuel Inventory	E8760	151,152	84,026	26,692	57,035	2,503	54,532	39,598	10,106	4,328	500	299
	Materials & Supplies												
27	Production	P10		136,170	46,239	89,547	3,945	85,602	62,577	15,830	6,447	749	384
28	Trans & Distr	TD		16,036	8,855	6,898	536	6,362	4,949	1,138	232	42	284
29	Total		154	152,207	55,094	96,445	4,481	91,964	67,526	16,968	6,679	791	668
	Prepayments												
30	Miscellaneous	NEPIS		106,071	46,735	58,165	3,264	54,900	41,102	10,054	3,309	436	1,172
31	Fuel	E8760		0	0	0	0	0	0	0	0	0	0
32	Insurance	NEPIS	135,143,184,186,232	0	0	0	0	0	0	0	0	0	0
33	Total		235,252,165	106,071	46,735	58,165	3,264	54,900	41,102	10,054	3,309	436	1,172
34	Non-Plant Assets & Liab	LABOR	190,283,	122,703	48,007	73,420	3,709	69,711	51,632	12,836	4,697	547	1,275
35	Working Cash	PT0	calculated	(153,713)	(69,938)	(82,127)	(4,807)	(77,319)	(58,093)	(14,100)	(4,526)	(600)	(1,648)
36	**Total Additions**			729,237	278,291	446,928	21,651	425,276	313,903	78,554	29,358	3,461	4,018
37	**Total Rate Base**			10,267,755	4,501,799	5,653,963	316,143	5,337,819	3,992,647	978,236	324,742	42,194	111,994
38	**Common Rate Base (@ 52.50%)**			5,390,571.4	2,363,444	2,968,330	165,975	2,802,355	2,096,140	513,574	170,490	22,152	58,797

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

Operating Rev (Cal Month)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Retail Revenue	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Present Rate Revenue	R01; (calc)	440, 442,444,445	3,053,147	1,197,981	1,827,841	103,959	1,723,881	1,305,159	289,940	112,730	16,053	27,326
2	Proposed Rate Revenue	PROREV; (calc)		3,555,766	1,415,538	2,107,646	116,207	1,991,439	1,506,193	337,229	129,586	18,432	32,582
3	Equal Rate Revenue			3,555,766	1,437,878	2,084,555	110,559	1,973,996	1,465,196	361,681	130,911	16,208	33,334
	Other Retail Revenue												
4	Interdepartmental	R01; R02	448	687	270	411	23	388	294	65	25	4	6
5	Gross Earnings Tax	R01; R02	408	0	0	0	0	0	0	0	0	0	0
6	CIP Adjustment to Program Costs	E99XCIP	456	0	0	0	0	0	0	0	0	0	0
7	**Tot Other Retail Rev**			687	270	411	23	388	294	65	25	4	6
	Other Operating Revenue												
8	Interchg Prod Capacity	P10	456	424,162	144,031	278,934	12,288	266,646	194,924	49,308	20,082	2,332	1,197
9	Interchg Prod Energy	E8760	456	0	0	0	0	0	0	0	0	0	0
10	Interchg Tr Bulk Supply	D10S	456	0	0	0	0	0	0	0	0	0	0
11	Dist Int Sales; Oth Serv	E8760	412,451,456	1,001	318	680	30	650	472	120	52	6	4
12	Dist Overhd Line Rent	POL	454	4,712	3,046	1,422	180	1,241	1,015	226	0	0	244
13	Connection Charges	C11	451	1,923	1,691	192	123	69	69	1	0	0	40
14	Sales For Resale	E8760	447	0	0	0	0	0	0	0	0	0	0
15	Joint Op Agree-Other PSCo Rev	D10S	456	0	0	0	0	0	0	0	0	0	0
16	Misc Ancillary Trans Rev	D10S		214,393	90,855	123,538	5,536	118,002	88,871	21,606	6,722	803	0
17	MISO	D10S	456	(95,384)	(40,422)	(54,962)	(2,463)	(52,499)	(39,539)	(9,612)	(2,991)	(357)	0
18	Other	D10S	451,456,457	6,881	2,916	3,965	178	3,787	2,852	693	216	26	0
19	Late Pay Chg - Pres	R16C; R02		5,448	4,628	817	164	653	597	56	0	0	3
20	**Tot Other Op - Pres**		450	563,137	207,064	354,585	16,036	338,549	249,261	62,398	24,081	2,809	1,488
21	Incr Misc Serv - Prop	C62NL		667	633	33	21	12	12	0	0	0	0
22	Incr Inter-Dept'l - Prop	R01; R02		101	40	61	3	57	43	10	4	1	1
23	Incr Late Pay - Prop	(R16C); R02		897	762	134	27	107	98	9	0	0	1
	Tot Incr Other Op			1,665	1,435	228	52	177	153	19	4	1	1
24	**Tot Other Op - Prop**			564,802	208,499	354,814	16,088	338,726	249,414	62,416	24,085	2,810	1,490
25	**Tot Oper Rev - Pres**			3,616,971	1,405,314	2,182,838	120,019	2,062,819	1,554,713	352,403	136,837	18,865	28,820
26	**Tot Oper Rev - Prop**			4,121,256	1,624,307	2,462,871	132,318	2,330,553	1,755,901	399,711	153,696	21,245	34,078
	Tot Oper Rev - Eql			4,121,256	1,646,646	2,439,780	126,671	2,313,109	1,714,905	424,163	155,021	19,021	34,830
	Operating & Maint (Pg 1 of 2)												
	Production Expen												
27	**Fuel**	E8760	501,518,547	620,527	197,121	421,200	18,485	402,716	292,430	74,632	31,959	3,694	2,206
	Purchased Power												
28	Purchases: Cap Peak	D10S		104,536	44,300	60,236	2,700	57,537	43,333	10,535	3,278	391	0
29	Purchases: Cap Base	D10S		38,900	16,485	22,415	1,005	21,411	16,125	3,920	1,220	146	0
30	Purchases: Demand		555	143,436	60,785	82,651	3,704	78,947	59,458	14,455	4,497	537	0
31	Purchases: Other Energy	E8760	555	299,310	95,081	203,165	8,916	194,249	141,053	35,999	15,416	1,782	1,064
32	Tot Non-Assoc Purch			442,746	155,866	285,816	12,620	273,196	200,511	50,454	19,913	2,319	1,064
33	Interchg Agr Capacity	P10WoN	557	43,834	15,147	28,572	1,260	27,312	20,003	5,047	2,025	236	115
34	Interchg Agr Energy	E8760	557	15,134	4,808	10,273	451	9,822	7,132	1,820	779	90	54
35	Tot Wis Interchg Purch			58,968	19,955	38,844	1,711	37,133	27,135	6,868	2,805	326	169
36	**Tot Purchased Power**			501,714	175,820	324,661	14,331	310,330	227,646	57,321	22,718	2,645	1,233
			500,502,505-507										
	Other Production		509-514,517-519,520,										
37	Capacity Related	D10S	523-525,528-532,535,	91,621	38,827	52,794	2,366	50,428	37,979	9,233	2,873	343	0
38	Energy Related	E8760	539,543-546,548-550	353,832	112,400	240,173	10,540	229,633	166,747	42,556	18,224	2,107	1,258
39	Total Other Produc	20.57%	552-554,556,557	445,453.065	151,227	292,968	12,906	280,061	204,726	51,789	21,096	2,450	1,258
			575.1-575.8										
40	**Total Production**			1,567,694	524,168	1,038,829	45,722	993,107	724,802	183,742	75,773	8,789	4,697
			560-563, 565-568										
41	**Transmission Exp**	D10S	570-573	259,111	109,805	149,306	6,691	142,614	107,408	26,112	8,124	970	0

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

Operating & Maint (Pg 2 of 2)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Distribution Expen	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Supervision & Eng'rg	ZDTS	580,590	12,710	7,838	4,149	535	3,614	2,965	638	11	1	722
2	Load Dispatching	T20D80	581	1,420	624	789	41	748	611	144	(8)	1	7
3	Substations	P61	582,591,592	7,927	3,425	4,458	230	4,228	3,360	857	11	0	44
4	Overhead Lines	POL	583,593	49,658	32,097	14,985	1,902	13,083	10,699	2,384	0	0	2,576
5	Underground Lines	PUL	584, 594	19,477	14,554	4,843	825	4,018	3,292	725	0	0	81
6	Line Transformers	P68	595	1,435	1,025	404	71	333	314	18	0	0	5
7	Meters	C12WM	586,597,598	2,114	1,462	647	219	427	407	19	1	0	5
8	Customer Install'n	OXDTS	587	3,908	2,467	1,209	152	1,057	865	192	0	0	232
9	Street Lighting	Dir Assign	585,596	2,315	0	0	0	0	0	0	0	0	2,315
10	Miscellaneous	OXDTS	588	28,105	17,742	8,695	1,095	7,601	6,218	1,381	1	1	1,667
11	Rents (Pole Attachmts)	POL	589	3,868	2,500	1,167	148	1,019	833	186	0	0	201
12	**Total Distribution**			132,937	83,736	41,346	5,217	36,128	29,565	6,545	15	3	7,855
13	**Customer Accounting**	C11WA	901-905	52,401	44,068	8,165	4,163	4,002	3,927	71	3	2	168
14	**Sales, Econ Dvlp & Other**	R01	912	284	111	170	10	160	121	27	10	1	3
	Admin & General												
15	Salaries	LABOR	920	81,071	31,719	48,510	2,451	46,059	34,113	8,481	3,103	361	843
16	Office Supplies	OXTS	921	59,333	22,395	36,543	1,819	34,724	25,635	6,374	2,424	291	394
17	Admin Transfer Credit	OXTS	922	(48,443)	(18,285)	(29,836)	(1,485)	(28,350)	(20,930)	(5,204)	(1,979)	(238)	(322)
18	Outside Services	LABOR	923	16,619	6,502	9,944	502	9,442	6,993	1,739	636	74	173
19	Property Insurance	NEPIS	924	7,400	3,260	4,058	228	3,830	2,867	701	231	30	82
20	Pensions & Benefits	LABOR	926	66,315	25,946	39,680	2,005	37,676	27,904	6,937	2,538	296	689
21	Injuries & Claims	LABOR	925	12,645	4,947	7,566	382	7,184	5,321	1,323	484	56	131
22	Regulatory Exp	R01; R02	928	6,160	2,417	3,688	210	3,478	2,633	585	227	32	55
23	General Advertising	OXTS	930.1	116	44	71	4	68	50	12	5	1	1
24	Contributions	OXTS		0	0	0	0	0	0	0	0	0	0
25	Misc General Exp	OXTS	929, 930.2	(815)	(308)	(502)	(25)	(477)	(352)	(88)	(33)	(4)	(5)
26	Rents	OXTS	931	34,735	13,111	21,393	1,065	20,328	15,007	3,732	1,419	170	231
27	Maint of General Plant	OXTS	935	141	53	87	4	82	61	15	6	1	1
28	Total			235,276	91,802	141,202	7,159	134,043	99,303	24,607	9,061	1,072	2,272
	Cust Service & Info												
29	Cust Assist Exp - Non-CIP	C11P10	908	2,403	1,464	910	112	799	595	140	57	7	28
30	CIP Total	E99XCIP	908	125,604.411	40,828	84,198	3,806	80,392	61,354	14,071	4,128	839	579
31	Instructional Advertising	C11P10	909	537	327	204	25	179	133	31	13	1	6
32	Total			128,545	42,620	85,312	3,943	81,369	62,082	14,242	4,198	847	614
33	Amortizations	LABOR		51,576	20,179	30,861	1,559	29,302	21,703	5,395	1,974	230	536
34	**Total O&M Expense**			2,427,824	916,489	1,495,190	74,464	1,420,726	1,048,912	260,742	99,159	11,913	16,145

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Book Depreciation												
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		109,327	46,330	62,997	2,823	60,174	45,319	11,018	3,428	409	0
2	Base Load	E8760		334,982	106,413	227,379	9,979	217,400	157,864	40,289	17,253	1,994	1,191
3	Total		403,413	444,309	152,743	290,376	12,802	277,574	203,183	51,307	20,681	2,404	1,191
	Transmission												
4	Gen Step Up Base	E8760		1,901	604	1,290	57	1,233	896	229	98	11	7
5	Gen Step Up Peak	D10S		1,119	474	645	29	616	464	113	35	4	0
6	Total Gen Step Up			3,019	1,078	1,935	86	1,849	1,359	341	133	16	7
7	Bulk Transmission	D10S		71,276	30,205	41,071	1,841	39,230	29,546	7,183	2,235	267	0
8	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
9	Direct Assign	Dir Assign		172	0	172	0	172	19	0	0	153	0
10	Total		403,413	74,468	31,283	43,178	1,926	41,252	30,924	7,524	2,368	436	7
	Distribution												
11	Generat Step Up	STRATH		69	23	45	2	43	32	8	3	0	0
12	Bulk Transmission	D10S		42	18	24	1	23	17	4	1	0	0
13	Distrib Function	D60Sub		16,882	7,489	9,296	502	8,794	7,329	1,719	(254)	0	97
14	Direct Assign	Dir Assign		426	0	426	0	426	9	150	267	0	0
15	Total Substations		403,413	17,419	7,530	9,791	505	9,287	7,387	1,881	17	1	98
16	Overhead Lines	POL		37,273	24,092	11,247	1,427	9,820	8,030	1,790	0	0	1,934
17	Underground	PUL		41,826	31,254	10,399	1,771	8,628	7,070	1,558	0	0	173
18	Line Transformers	P68		11,170	7,985	3,144	554	2,591	2,448	142	0	0	41
19	Services	P69		10,352	9,338	1,015	302	713	713	0	0	0	0
20	Meters	C12WM		5,447	3,768	1,666	565	1,101	1,050	49	1	1	12
21	Street Lighting	P73		3,821	0	0	0	0	0	0	0	0	3,821
22	Total		403,413	127,307	83,966	37,262	5,123	32,139	26,699	5,420	19	1	6,079
23	**General & Common Plant**	PTD	403,413	132,288	56,004	75,134	4,064	71,070	52,924	13,018	4,550	578	1,150
24	**Total Book Deprec**		403,404	778,372	323,996	445,950	23,915	422,034	313,729	77,269	27,618	3,419	8,426
	Real Estate & Property Tax												
	Production												
25	Peaking Plant	D10S		25,339	10,738	14,601	654	13,946	10,503	2,554	794	95	0
26	Base Load	E8760		71,048	22,569	48,226	2,116	46,109	33,482	8,545	3,659	423	253
27	Total		408.1	96,386	33,307	62,826	2,771	60,056	43,985	11,099	4,454	518	253
	Transmission												
28	Gen Step Up Base	E8760		1,251.4196	398	849	37	812	590	151	64	7	4
29	Gen Step Up Peak	D10S		471.9465	200	272	12	260	196	48	15	2	0
30	Total Gen Step Up			1,723.3660	598	1,121	49	1,072	785	198	79	9	4
31	Bulk Transmission	D10S		44,109.5299	18,693	25,417	1,139	24,278	18,284	4,445	1,383	165	0
32	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
33	Direct Assign	Dir Assign		105	0	105	0	105	12	0	0	94	0
34	Total		408.1	45,938.322	19,290	26,644	1,189	25,455	19,081	4,643	1,462	268	4
	Distribution												
35	Generat Step Up	STRATH		41	14	27	1	26	19	5	2	0	0
36	Bulk Transmission	D10S		24	10	14	1	13	10	2	1	0	0
37	Distrib Function	D60Sub		10,009	4,440	5,511	297	5,214	4,345	1,019	(150)	0	58
38	Direct Assign	Dir Assign		258	0	258	0	258	6	91	162	0	0
39	Total Substations			10,333	4,464	5,811	299	5,512	4,380	1,118	14	0	58
40	Overhead Lines	POL		14,655	9,472	4,422	561	3,861	3,157	704	0	0	760
41	Underground	PUL		22,201	16,590	5,520	940	4,580	3,753	827	0	0	92
42	Line Transformers	P68		5,469	3,909	1,539	271	1,268	1,199	70	0	0	20
43	Services	P69		3,976	3,587	390	116	274	274	0	0	0	0
44	Meters	C12WM		1,460	1,010	447	151	295	281	13	0	0	3
45	Street Lighting	P73		968	0	0	0	0	0	0	0	0	968
46	Total		408.1	59,063	39,032	18,129	2,339	15,790	13,044	2,731	14	1	1,902
47	**General & Common Plant**	PTD	408.1	0	0	0	0	0	0	0	0	0	0
48	**Tot Rl Est & Pr Tax**			201,387	91,630	107,599	6,298	101,300	76,111	18,473	5,930	787	2,159
49	Gross Earnings Tax	R01; R02		0	0	0	0	0	0	0	0	0	0
50	Payroll Taxes	LABOR		28,067	10,981	16,794	848	15,946	11,810	2,936	1,074	125	292
51	**Tot Non-Inc Taxes**			229,454	102,611	124,393	7,147	117,246	87,921	21,409	7,005	912	2,451

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

Provision For Defer Inc Tax

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		(6,273)	(2,658)	(3,614)	(162)	(3,452)	(2,600)	(632)	(197)	(23)	0
2	Nuclear Fuel	E8760		(2,089)	(664)	(1,418)	(62)	(1,356)	(984)	(251)	(108)	(12)	(7)
3	Base Load	E8760		13,945	4,430	9,466	415	9,050	6,572	1,677	718	83	50
4	Total		410, 411	5,584	1,108	4,433	191	4,242	2,987	794	414	47	42
	Transmission												
5	Gen Step Up Base	E8760		669	213	454	20	434	315	81	34	4	2
6	Gen Step Up Peak	D10S		231	98	133	6	127	96	23	7	1	0
7	Total Gen Step Up			901	311	588	26	562	411	104	42	5	2
8	Bulk Transmission	D10S		5,598	2,372	3,226	145	3,081	2,321	564	176	21	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		14	0	14	0	14	2	0	0	12	0
11	Total		410, 411	6,512	2,683	3,827	170	3,657	2,733	668	217	38	2
	Distribution												
12	Generat Step Up	STRATH		(28)	(9)	(18)	(1)	(17)	(13)	(3)	(1)	(0)	(0)
13	Bulk Transmission	D10S		(7)	(3)	(4)	(0)	(4)	(3)	(1)	(0)	(0)	0
14	Distrib Function	D60Sub		397	176	219	12	207	172	40	(6)	0	2
15	Direct Assign	Dir Assign		(49)	0	(49)	0	(49)	(1)	(17)	(31)	(0)	0
16	Total Substations			314	164	147	11	136	156	19	(38)	(0)	2
17	Overhead Lines	POL		3,765	2,434	1,136	144	992	811	181	0	0	195
18	Underground	PUL		(666)	(498)	(166)	(28)	(137)	(113)	(25)	0	0	(3)
19	Line Transformers	P68		(2,352)	(1,681)	(662)	(117)	(545)	(516)	(30)	0	0	(9)
20	Services	P69		(1,750)	(1,579)	(172)	(51)	(121)	(121)	0	0	0	0
21	Meters	C12WM		679	470	208	70	137	131	6	0	0	2
22	Street Lighting	P73		(619)	0	0	0	0	0	0	0	0	(619)
23	Total		410, 411	(630)	(690)	492	30	462	349	151	(38)	(0)	(432)
24	**General & Common Plant**	PTD	410, 411	(7)	(3)	(4)	(0)	(4)	(3)	(1)	(0)	(0)	(0)
25	**Net Operating Loss (NOL) Carry**	NEPIS		(161,680)	(71,236)	(88,658)	(4,976)	(83,682)	(62,650)	(15,324)	(5,044)	(665)	(1,786)
26	**Non - Plant Related**	LABOR	410, 411	4,656	1,822	2,786	141	2,645	1,959	487	178	21	48
27	**Tot Prov For Defer**			(145,565)	(66,316)	(77,123)	(4,444)	(72,679)	(54,623)	(13,225)	(4,273)	(559)	(2,125)

Inv Tax Credit; Total Oper Exp

				MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
	Production												
28	Peaking Plant	D10S		(260)	(110)	(150)	(7)	(143)	(108)	(26)	(8)	(1)	0
29	Base Load	E8760		(538)	(171)	(365)	(16)	(349)	(254)	(65)	(28)	(3)	(2)
30	Total		411	(798)	(281)	(515)	(23)	(492)	(361)	(91)	(36)	(4)	(2)
	Transmission												
31	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
32	Gen Step Up Peak	D10S		0	0	0	0	0	0	0	0	0	0
33	Total Gen Step Up			0	0	0	0	0	0	0	0	0	0
34	Bulk Transmission	D10S		(150)	(64)	(86)	(4)	(83)	(62)	(15)	(5)	(1)	0
35	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
36	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
37	Total		411	(150)	(64)	(86)	(4)	(83)	(62)	(15)	(5)	(1)	0
	Distribution												
38	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
39	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
40	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
41	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
42	Total Substations			0	0	0	0	0	0	0	0	0	0
43	Overhead Lines	POL		(267)	(173)	(81)	(10)	(70)	(58)	(13)	0	0	(14)
44	Underground	PUL		0	0	0	0	0	0	0	0	0	0
45	Line Transformers	P68		0	0	0	0	0	0	0	0	0	0
46	Services	P69		0	0	0	0	0	0	0	0	0	0
47	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
48	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
49	Total		411	(267)	(173)	(81)	(10)	(70)	(58)	(13)	0	0	(14)
50	**General & Common Plant**	PTD	411	(7)	(3)	(4)	(0)	(4)	(3)	(1)	(0)	(0)	(0)
51	**Net Inv Tax Credit**			(1,222)	(520)	(686)	(37)	(649)	(484)	(120)	(41)	(5)	(16)
28	TBT Misc Net Exp	NEPIS		0	0	0	0	0	0	0	0	0	0
52	**Total Operating Exp**			**3,288,864**	**1,276,260**	**1,987,723**	**101,045**	**1,886,678**	**1,395,454**	**346,076**	**129,468**	**15,680**	**24,881**
53A	**Pres Op Inc Before Inc Tax**			**328,108**	**129,054**	**195,114**	**18,974**	**176,141**	**159,259**	**6,327**	**7,369**	**3,185**	**3,939**
53B	**Prop Op Inc Before Inc Tax**			**832,392**	**348,047**	**475,148**	**31,273**	**443,875**	**360,447**	**53,635**	**24,228**	**5,565**	**9,197**

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

Tax Deprec; Inc Tax & Return

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		108,516	45,987	62,529	2,802	59,727	44,983	10,936	3,403	406	0
2	Nuclear Fuel	E8760		94,356	29,974	64,047	2,811	61,236	44,466	11,348	4,860	562	335
3	Base Load	E8760		472,772	150,184	320,907	14,083	306,824	222,799	56,861	24,349	2,815	1,681
4	Total		tax books	675,644	226,144	447,483	19,696	427,787	312,247	79,145	32,612	3,783	2,016
	Transmission												
5	Gen Step Up Base	E8760		4,443	1,412	3,016	132	2,884	2,094	534	229	26	16
6	Gen Step Up Peak	D10S		1,603	679	924	41	882	665	162	50	6	0
7	Total Gen Step Up			6,047	2,091	3,940	174	3,766	2,759	696	279	32	16
8	Bulk Transmission	D10S		100,073	42,408	57,664	2,584	55,080	41,483	10,085	3,138	375	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		239	0	239	0	239	26	0	0	213	0
11	Total		tax books	106,358	44,499	61,843	2,758	59,085	44,267	10,781	3,417	620	16
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		17	7	10	0	10	7	2	1	0	0
14	Distrib Function	D60Sub		20,079	8,907	11,056	596	10,459	8,717	2,045	(302)	0	116
15	Direct Assign	Dir Assign		249	0	249	0	249	5	88	156	0	0
16	Total Substations			20,345	8,914	11,315	597	10,718	8,729	2,134	(145)	0	116
17	Overhead Lines	POL		50,716	32,781	15,304	1,942	13,362	10,927	2,435	0	0	2,631
18	Underground	PUL		45,992	34,367	11,435	1,948	9,487	7,774	1,713	0	0	191
19	Line Transformers	P68		8,788	6,282	2,474	436	2,038	1,926	112	0	0	32
20	Services	P69		4,877	4,399	478	142	336	336	0	0	0	0
21	Meters	C12WM		7,750	5,362	2,371	804	1,567	1,493	70	2	1	18
22	Street Lighting	P73		2,239	0	0	0	0	0	0	0	0	2,239
23	Total		tax books	140,708	92,106	43,376	5,868	37,508	31,186	6,464	(143)	1	5,226
24	**General & Common Plant**	PTD	tax books	156,227	66,139	88,730	4,799	83,931	62,501	15,374	5,374	683	1,358
25	Net Operating Loss (NOL) Carry F	NEPIS		0	0	0	0	0	0	0	0	0	0
26	**Total Tax Deprec**			1,078,937	428,888	641,433	33,122	608,311	450,201	111,764	41,259	5,086	8,616
27	Interest Expense		427,431	203,301.55	89,136	111,948	6,260	105,689	79,054	19,369	6,430	835	2,217
28	Other Tax Timing Differ	LABOR		6,154	2,408	3,682	186	3,496	2,589	644	236	27	64
29	Meals & Enter	LABOR		1,112	435	665	34	632	468	116	43	5	12
30	Total Tax Deductions			1,289,504	520,866	757,729	39,601	718,128	532,313	131,893	47,967	5,954	10,909
	Inc Tax Additions												
31	Book Depreciation			778,372	323,996	445,950	23,915	422,034	313,729	77,269	27,618	3,419	8,426
32	Deferred Inc Tax & ITC			(146,787.19)	(66,837)	(77,809)	(4,481)	(73,328)	(55,107)	(13,344)	(4,313)	(564)	(2,141)
33	Nuclear Fuel Book Burn	E8760		104,901	33,324	71,205	3,125	68,080	49,436	12,617	5,403	625	373
34	Tax Capitalized Leases	PTD		40,472	17,134	22,986	1,243	21,743	16,191	3,983	1,392	177	352
35	Avoided Tax Interest	RTBASE		12,878	5,646	7,091	397	6,695	5,008	1,227	407	53	140
36	Total Tax Additions			789,836	313,263	469,422	24,199	445,223	329,256	81,751	30,507	3,709	7,151
37	**Total Inc Tax Adjustments**			(499,668)	(207,603)	(288,306)	(15,402)	(272,904)	(203,057)	(50,142)	(17,460)	(2,245)	(3,759)
38A	**Pres Taxable Net Income**			(171,560)	(78,549)	(93,192)	3,572	(96,764)	(43,798)	(43,815)	(10,091)	940	180
38B	**Prop Taxable Net Income**			332,724	140,444	186,842	15,871	170,971	157,390	3,493	6,768	3,320	5,438
39A	Pres Fed & State Inc Tax			(41,137)	(18,993)	(22,285)	1,278	(23,563)	(9,411)	(11,815)	(2,642)	304	141
38A	Exp Fed & State Inc Tax			103,804	38,103	64,267	6,212	58,055	52,389	1,910	2,693	1,064	1,434
39B	Prop Fed & State Inc Tax			103,804	43,950	58,202	4,813	53,389	48,415	1,783	2,204	988	1,652
40A	Pres Preliminary Return	(total); BASE		369,245	148,048	217,399	17,695	199,704	168,670	18,142	10,011	2,881	3,798
40B	Prop Preliminary Return	(total); BASE		728,588	304,098	416,946	26,460	390,486	312,032	51,853	22,025	4,577	7,545
41	Total AFUDC			25,065	10,416	14,509	769	13,740	10,242	2,526	867	105	140
42A	**Present Total Return**			394,310	158,464	231,909	18,465	213,444	178,911	20,668	10,878	2,986	3,938
42B	**Proposed Total Return**			753,653	314,514	431,455	27,229	404,226	322,274	54,379	22,892	4,682	7,684
43A	**Pres % Return on Rate Base**			3.84%	3.52%	4.10%	5.84%	4.00%	4.48%	2.11%	3.35%	7.08%	3.52%
43B	**Prop % Return on Rate Base**			7.34%	6.99%	7.63%	8.61%	7.57%	8.07%	5.56%	7.05%	11.10%	6.86%
44A	**Present Common Return**			191,009	69,328	119,960	12,205	107,755	99,857	1,299	4,448	2,151	1,720
44B	**Proposed Common Return**			550,352	225,378	319,507	20,969	298,537	243,219	35,010	16,462	3,847	5,467
45A	**Pres % Ret on Common Rt Base**			3.54%	2.93%	4.04%	7.35%	3.85%	4.76%	0.25%	2.61%	9.71%	2.93%
45B	**Prop % Ret on Common Rt Base**			10.21%	9.54%	10.76%	12.63%	10.65%	11.60%	6.82%	9.66%	17.36%	9.30%

Northern States Power Company

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	Allow For Funds Used During Constr			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		2,550	1,081	1,469	66	1,403	1,057	257	80	10	0
2	Nuclear Fuel	E8760		4,682	1,487	3,178	139	3,039	2,206	563	241	28	17
3	Base Load	E8760		4,110	1,305	2,790	122	2,667	1,937	494	212	24	15
4	Total		419.1,432	11,342	3,873	7,437	328	7,109	5,200	1,314	533	62	31
	Transmission												
5	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10S		0	0	0	0	0	0	0	0	0	0
7	Total Gen Step Up			0	0	0	0	0	0	0	0	0	0
8	Bulk Transmission	D10S		4,054	1,718	2,336	105	2,231	1,680	409	127	15	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
11	Total		419.1,432	4,054	1,718	2,336	105	2,231	1,680	409	127	15	0
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		794	352	437	24	414	345	81	(12)	0	5
15	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
16	Total Substations			794	352	437	24	414	345	81	(12)	0	5
17	Overhead Lines	POL		812	525	245	31	214	175	39	0	0	42
18	Underground	PUL		1,445	1,080	359	61	298	244	54	0	0	6
19	Line Transformers	P68		0	0	0	0	0	0	0	0	0	0
20	Services	P69		0	0	0	0	0	0	0	0	0	0
21	Meters	C12WM		244	169	75	25	49	47	2	0	0	1
22	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
23	Total		419.1,432	3,296	2,126	1,117	141	975	811	176	(12)	0	53
24	**General & Common Plant**	PTD	419.1,432	6,374	2,698	3,620	196	3,424	2,550	627	219	28	55
25	**Total AFUDC**			25,065	10,416	14,509	769	13,740	10,242	2,526	867	105	140
	Labor Allocator												
	Production												
26	Other Prod - Cap	D10S		71,005	30,090	40,915	1,834	39,081	29,433	7,156	2,226	266	0
27	Other Prod - Ene	E8760		199,093	63,245	135,140	5,931	129,209	93,825	23,945	10,254	1,185	708
28	Total		500 through 557	270,098	93,335	176,055	7,764	168,290	123,258	31,101	12,480	1,451	708
	Transmission												
29	Stepup Subtrans	P5161A		1,326	459	863	38	825	604	152	61	7	3
30	Bulk Power Subs	D10S		33,939	14,383	19,557	876	18,680	14,069	3,420	1,064	127	0
31	Total		560 through 571	35,265	14,842	20,420	915	19,505	14,673	3,573	1,125	134	3
	Distribution												
32	Superv & Eng	ZDTS	580, 590	11,402	7,031	3,722	480	3,242	2,659	572	10	1	648
33	Load Dispatch	D10S	581	737	312	425	19	406	306	74	23	3	0
34	Substation	P61	582, 592	5,382	2,325	3,027	156	2,871	2,281	582	7	0	30
35	Overhead Lines	POL	583, 593	9,451	6,109	2,852	362	2,490	2,036	454	0	0	490
36	Underground Lines	PUL	584, 594	7,840	5,858	1,949	332	1,617	1,325	292	0	0	32
37	Line Transformer	P68	595	1,219	872	343	60	283	267	16	0	0	4
38	Meter	C12WM	586, 597	2,933	2,029	897	304	593	565	27	1	0	7
39	Cust Installation	ZDTS	587	3,573	2,204	1,167	150	1,016	833	179	3	0	203
40	Street Lighting	P73	585, 596	1,039	0	0	0	0	0	0	0	0	1,039
41	Miscellaneous	OXDTS	588	9,107	5,749	2,817	355	2,463	2,015	447	0	0	540
42	Total			52,683	32,490	17,199	2,219	14,980	12,289	2,643	44	5	2,994
43	**Cust Accounting**	C11WA	901,902,903,904,905	(1,956)	(1,645)	(305)	(155)	(149)	(147)	(3)	(0)	(0)	(6)
44	**Sales Expense**	C11P10	912	9	5	3	0	3	2	0	0	0	0
45	**Admin & General**	LABOR	920,921,922,923,924,	149,243	58,391	89,301	4,511	84,790	62,799	15,613	5,712	665	1,551
46	**Service & Inform**	C11P10	908, 909	1,352	824	512	63	449	335	79	32	4	16
47	**Labor**			506,694	198,242	303,185	15,317	287,869	213,210	53,006	19,394	2,259	5,267

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			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	
INTERNAL ALLOCATORS		Intern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	50% Cus, 50% Prod Plt	C11P10	100.00%	60.94%	37.88%	4.64%	33.24%	24.77%	5.83%	2.37%	0.28%	1.18%
2	Peaking Plant Capacity	D10S	100.00%	42.38%	57.62%	2.58%	55.04%	41.45%	10.08%	3.14%	0.37%	0.00%
3	57% Dmd; 43% Energy: Sales & E	D57E43	100.00%	31.77%	67.88%	2.98%	64.90%	47.13%	12.03%	5.15%	0.60%	0.36%
4	40% Dmd; 60% Energy: CIP	D40E60	100.00%	31.77%	67.88%	2.98%	64.90%	47.13%	12.03%	5.15%	0.60%	0.36%
5	20%D10T; 80%D60Sub	T20D80	100.00%	43.96%	55.57%	2.89%	52.68%	43.02%	10.16%	-0.58%	0.07%	0.46%
6	Labor w/o (or w/) A&G	LABOR	100.00%	39.12%	59.84%	3.02%	56.81%	42.08%	10.46%	3.83%	0.45%	1.04%
7	Net Plant In Service	NEPIS	100.00%	44.06%	54.84%	3.08%	51.76%	38.75%	9.48%	3.12%	0.41%	1.10%
8	Dis O&M w/o Sup & Misc	OXDTS	100.00%	63.13%	30.94%	3.89%	27.04%	22.12%	4.91%	0.00%	0.00%	5.93%
9	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	100.00%	37.75%	61.59%	3.07%	58.52%	43.20%	10.74%	4.09%	0.49%	0.66%
10	Production Plant	P10	100.00%	33.96%	65.76%	2.90%	62.86%	45.96%	11.62%	4.73%	0.55%	0.28%
11	Production Plant Wo Nuclear	P10WoN	100.00%	34.56%	65.18%	2.87%	62.31%	45.63%	11.51%	4.62%	0.54%	0.26%
12	Total P51 & P61A	P5161A	100.00%	34.65%	65.09%	2.87%	62.22%	45.59%	11.50%	4.60%	0.54%	0.26%
13	Distribution Plant	P60	100.00%	66.09%	30.69%	3.96%	26.73%	22.09%	4.62%	0.02%	0.00%	3.22%
14	Distr Substn Plant	P61	100.00%	43.20%	56.23%	2.90%	53.34%	42.39%	10.81%	0.13%	0.00%	0.56%
15	Line Transformer Plant	P68	100.00%	71.49%	28.15%	4.96%	23.19%	21.92%	1.27%	0.00%	0.00%	0.36%
16	Services Plant	P69	100.00%	90.20%	9.80%	2.91%	6.89%	6.89%	0.00%	0.00%	0.00%	0.00%
17	Dist Plt Overhead Lines	POL	100.00%	64.64%	30.18%	3.83%	26.35%	21.54%	4.80%	0.00%	0.00%	5.19%
18	Real Est & Property Tax	PT0	100.00%	45.50%	53.43%	3.13%	50.30%	37.79%	9.17%	2.94%	0.39%	1.07%
19	Produc, Trans & Distrib	PTD	100.00%	42.34%	56.80%	3.07%	53.72%	40.01%	9.84%	3.44%	0.44%	0.87%
20	Dist Plt Undground Lines	PUL	100.00%	74.72%	24.86%	4.23%	20.63%	16.90%	3.72%	0.00%	0.00%	0.41%
21	Rate Base (Non-Column)	RTBASE	100.00%	43.84%	55.07%	3.08%	51.99%	38.89%	9.53%	3.16%	0.41%	1.09%
22	Stratified Hydro Baseload	STRATH	100.00%	33.57%	66.14%	2.91%	63.23%	46.16%	11.70%	4.81%	0.56%	0.30%
23	Transmission & Distrib	TD	100.00%	55.22%	43.01%	3.34%	39.67%	30.86%	7.10%	1.45%	0.26%	1.77%
24	Labor Dis w/o Sup & Eng	ZDTS	100.00%	61.67%	32.65%	4.21%	28.44%	23.33%	5.02%	0.08%	0.01%	5.68%

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
INTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
25	Labor w/o A&G	LABOR(S)	357,451	139,851	213,884	10,805	203,079	150,410	37,393	13,682	1,594	3,715
26	Dis O&M w/o Sup, Cust Install & M	OXDTS	88,214	55,688	27,292	3,435	23,856	19,517	4,335	3	2	5,234
27	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	2,376,598	897,062	1,463,746	72,873	1,390,873	1,026,808	255,316	97,090	11,660	15,790
28	Total P51 & P61A	P5161A	137,836	47,757	89,722	3,958	85,764	62,833	15,848	6,345	738	357
29	Produc, Trans & Distrib	PTD	20,208,766	8,555,403	11,477,710	620,794	10,856,916	8,084,781	1,988,669	695,139	88,326	175,652
30	Transmission & Distrib	TD	7,964,309	4,397,593	3,425,615	266,067	3,159,547	2,457,834	565,274	115,426	21,013	141,102
31	Labor Dis w/o Sup & Eng, Cust In	ZDTS	37,708	23,255	12,310	1,588	10,722	8,796	1,892	31	3	2,143

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

2022 Class Cost of Service Study Detail ($000)

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
EXTERNAL ALLOCATORS		Extern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Customers - Ave Monthly	C11	100.00%	87.92%	10.00%	6.39%	3.61%	3.58%	0.04%	0.00%	0.00%	2.08%
2	Cust Acctg Wtg Factor	C11WA	100.00%	84.10%	15.58%	7.94%	7.64%	7.50%	0.13%	0.00%	0.00%	0.32%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	69.18%	30.59%	10.37%	20.22%	19.27%	0.91%	0.03%	0.01%	0.23%
4	Sec & Pri Customers	C61PS	100.00%	89.39%	10.18%	6.50%	3.68%	3.65%	0.04%	0.00%	0.00%	0.43%
5	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	100.00%	95.13%	4.49%	3.83%	0.66%	0.65%	0.01%	0.00%	0.00%	0.38%
6	C62Sec, w/o Ltg & C/I Undergrou	C62NL	100.00%	95.01%	4.99%	3.20%	1.79%	1.79%	0.00%	0.00%	0.00%	0.00%
7	Secondary Customers	C62Sec	100.00%	89.42%	10.15%	6.50%	3.65%	3.65%	0.00%	0.00%	0.00%	0.43%
8	Summer Peak Resp KW	D10S	100.00%	42.38%	57.62%	2.58%	55.04%	41.45%	10.08%	3.14%	0.37%	0.00%
9	Transmission Demand %	D10T	100.00%	39.79%	59.89%	2.84%	57.04%	42.66%	10.25%	3.61%	0.53%	0.32%
10	Winter Peak Resp KW	D10W	100.00%	36.12%	63.10%	3.22%	59.89%	44.37%	10.49%	4.28%	0.75%	0.78%
11	Alternative Production Allocator	1CP	100.00%	42.38%	57.62%	2.58%	55.04%	41.45%	10.08%	3.14%	0.37%	0.00%
12	Sec, Pri & TT, Class Coin kW @ S	D60Sub	100.00%	44.36%	55.06%	2.97%	52.09%	43.41%	10.18%	-1.50%	0.00%	0.58%
13	Sec & Pri, Cl Coin kW (no Min Sy	D61PS	100.00%	38.69%	60.98%	2.45%	58.53%	46.79%	11.74%	0.00%	0.00%	0.33%
14	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	100.00%	76.44%	23.01%	2.68%	20.33%	15.50%	4.83%	0.00%	0.00%	0.55%
15	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	100.00%	75.07%	24.93%	2.03%	22.91%	22.91%	0.00%	0.00%	0.00%	0.00%
16	Sec, Class Coin kW (w/o Min Sys	D62SecL	100.00%	50.98%	48.76%	3.08%	45.68%	45.68%	0.00%	0.00%	0.00%	0.26%
17	Direct Assign Street Lighting	DASL	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
18	On + Off Sales MWH	E8760	100.00%	31.77%	67.88%	2.98%	64.90%	47.13%	12.03%	5.15%	0.60%	0.36%
19	Street Lighting (Dir Assign)	P73	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
20	MWh Sales Excl CIP Exempt	E99XCIP	100.00%	32.50%	67.03%	3.03%	64.004%	48.85%	11.20%	3.29%	0.67%	0.46%
21	Present Rev	R01	100.0000%	39.2376%	59.8674%	3.4050%	56.4624%	42.7480%	9.4964%	3.6923%	0.5258%	0.8950%
22	Late Fee Revenue Allocator	LateFee	100.00%	84.95%	14.99%	3.01%	11.98%	10.95%	1.02%	0.01%	0.00%	0.06%

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
EXTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
23	Customers - B Basis	C10	1,322,874	1,182,433	134,730	85,996	48,735	48,240	472	13	9	5,710
24	Cust - Ave Monthly (C10-Area Lt)	C11	1,349,008	1,186,060	134,925	86,190	48,735	48,240	472	13	9	28,023
25	Mo Cus Wtd By Cus Acct	C11WA	1,410,339	1,186,060	219,769	112,047	107,722	105,707	1,901	70	44	4,510
26	Cust Acctg Wtg Factor	C11WAF	18.77	1.00	17.77	1.30	16.47	2.19	4.02	5.35	4.91	N/A
27	Cust-Ave Mo (C11 w/ Dir Assign S	C12	1,323,697	1,186,060	134,925	86,190	48,735	48,240	472	13	9	2,713
28	Mo Cus Wtd By Mtr Invest	C12WM	168,279,367	116,423,459	51,473,112	17,452,292	34,020,821	32,426,134	1,528,774	44,906	21,007	382,796
29	Meter Invest / Cust Factor	C12WMF	10,138	98	9,899	202	9,697	672	3,236	3,454	2,334	141
30	Sec & Pri Customers	C61PS	1,322,852	1,182,433	134,708	85,996	48,713	48,240	472	0	0	5,710
31	% Served by Primary Single Phase		0.0%	73.13%	0.00%	40.49%	0.00%	12.26%	15.23%	18.18%	22.22%	61.24%
32	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	909,018	864,719	40,803	34,818	5,985	5,913	72	0	0	3,497
33	C62Sec, w/o Ltg & C/I Undergrou	C62NL	1,244,540	1,182,433	62,107	39,787	22,319	22,319	0	0	0	0
34	Secondary Customers	C62Sec	1,322,379	1,182,433	134,236	85,996	48,240	48,240	0	0	0	5,710
35	Summer Peak Resp KW	D10S	35,910	15,218	20,692	927	19,765	14,886	3,619	1,126	134	0
36	Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	3,979,319	5,988,589	284,375	5,704,214	4,265,644	1,024,951	360,626	52,994	32,092
37	Winter Peak Resp KW	D10W	4,161	1,503	2,626	134	2,492	1,846	437	178	31	32
38	Alternative Production Allocator	1CP	35,910	15,218	20,692	927	19,765	14,886	3,619	1,126	134	0
39	Sec, Pri & TT, Class Coin kW @ S	D60Sub	6,153,986	2,729,960	3,388,516	182,820	3,205,696	2,671,577	626,627	(92,508)	0	35,510
40	Sec & Pri, Class Coin kW (w/o Mi	D61PS	5,642,139	2,182,789	3,440,485	138,274	3,302,211	2,639,932	662,279	0	0	18,865
41	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	2,088,285	1,596,283	480,448	55,984	424,464	323,587	100,877	0	0	11,553
42	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	11,095,862	8,329,112	2,766,750	224,878	2,541,872	2,541,872	0	0	0	0
43	Sec, Class Coin kW (w/o Min Sys	D62SecL	10,000,000	5,098,210	4,876,265	308,447	4,567,818	4,567,818	0	0	0	25,525
44	Annual Billing kW	D99	47,159.100	0	47,159	0	47,159	36,365	7,511	2,776	507	0
45	Summer Billing kW	D99S	17,322.925	0	17,323	0	17,323	13,365	2,808	961	189	0
46	Winter Billing kW	D99W	29,836.175	0	29,836	0	29,836	23,000	4,703	1,815	318	0
47	Non-Coinc Pk Second	DN-Sec	14,327,964	8,329,112	5,979,987	486,045	5,493,942	5,493,942	0	0	0	18,865
48	MWh Sales	E99	27,524,195	8,554,019	18,848,849	797,589	18,051,260	12,923,759	3,418,503	1,533,254	175,744	121,327
49	MWh Sales Excl CIP Exempt	E99XCIP	26,316,029	8,554,019	17,640,683	797,442	16,843,242	12,854,523	2,948,012	864,963	175,744	121,327
50	Late Fee Revenue Allocation	LateFee	100.00%	84.95%	14.99%	3.01%	11.98%	10.95%	1.02%	0.01%	0.00%	0.06%

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

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

Docket No. E002/GR-20-723
Exhibit___(MAP-1), Schedule 7

UNADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	3,626,179	1,458,002	112,483	2,021,089	34,605
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,854	1,588	58	206	2
[3]	Unadjusted Operating Revenues (line 1 + line 2)	3,628,033	1,459,590	112,540	2,021,296	34,607
[4]	Present Rates (CCOSS page 2, line 2)	3,030,677	1,184,879	103,902	1,714,543	27,353
[5]	Unadjusted Deficiency (line 3 - line 4)	597,356	274,712	8,638	306,752	7,254
[6]	Defic / Pres (line 5 / line 4)	19.7%	23.2%	8.3%	17.9%	26.5%
[7]	**Ratio: Class % / Total %**	**1.00**	**1.18**	**0.42**	**0.91**	**1.35**

COST RESPONSIBILITIES FOR RATE DISCOUNTS

		Total	Residential	Non-Demand	Demand	Street Ltg
		[PROTECTED DATA 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)					
						PROTECTED DATA ENDS]
[12]	Revenue Requirement Change (lines 10 & 11 - lines 8 & 9)	0	(2,103)	778	1,319	6

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[13]	Adjusted Rate Revenue Reqt (line 1 + line 12)	3,626,179	1,455,899	113,261	2,022,409	34,611
[14]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,854	1,588	58	206	2
[15]	Adjusted Operating Revenues (line 13 + line 14)	3,628,033	1,457,487	113,319	2,022,615	34,612
[16]	Present Rates (line 4)	3,030,677	1,184,879	103,902	1,714,543	27,353
[17]	Adjusted Deficiency (line 15 - line 16)	597,356	272,609	9,416	308,071	7,260
[18]	**Defic / Pres Rates (line 17 / line 16)**	**19.7%**	**23.0%**	**9.1%**	**18.0%**	**26.5%**
[19]	**Ratio: Class % / Total %**	**1.00**	**1.17**	**0.46**	**0.91**	**1.35**

PROPOSED REVENUE RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[20]	Proposed Rates (CCOSS page 3, line 3)	3,626,179	1,436,798	118,789	2,036,922	33,669
[21]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,854	1,588	58	206	2
[22]	Proposed Operating Revenues (line 20 + line 21)	3,628,033	1,438,386	118,847	2,037,129	33,671
[23]	Proposed Increase (line 22 - line 16)	597,356	253,508	14,945	322,585	6,318
[24]	Difference / Pres (line 23 / line 16)	19.7%	21.4%	14.4%	18.8%	23.1%
[25]	**Ratio: Class % / Total %**	**1.00**	**1.09**	**0.73**	**0.95**	**1.17**

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company

2023 Class Cost of Service Detail ($000)

Rate Base

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Plant In Service	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Production		12,391,493	4,175,999	8,180,650	359,027	7,821,622	5,718,652	1,394,149	576,081	132,741	34,845
2	Transmission		3,743,932	1,562,266	2,181,320	97,873	2,083,447	1,559,136	369,911	117,646	36,753	346
3	Distribution		4,673,765	3,041,076	1,483,321	186,438	1,296,883	1,071,305	223,948	1,566	63	149,369
4	General		2,257,788	952,555	1,285,209	69,802	1,215,407	905,873	215,698	75,439	18,397	20,025
5	Common		0	0	0	0	0	0	0	0	0	0
6	Total Plant In Service		23,066,979	9,731,895	13,130,499	713,141	12,417,358	9,254,966	2,203,706	770,732	187,953	204,585
7	Production		7,511,111	2,524,324	4,965,432	217,862	4,747,570	3,470,163	846,219	350,476	80,712	21,354
8	Transmission		898,294	375,614	522,632	23,432	499,200	373,335	88,521	28,017	9,327	48
9	Distribution		1,647,751	1,101,417	506,690	67,382	439,307	366,084	72,358	825	40	39,644
10	General		1,188,076	501,246	676,293	36,731	639,562	476,681	113,503	39,697	9,681	10,537
11	Common		0	0	0	0	0	0	0	0	0	0
12	Total Depreciation Reserve		11,245,231	4,502,601	6,671,046	345,407	6,325,639	4,686,264	1,120,601	419,016	99,759	71,584
13	**Net Plant In Service**		11,821,748	5,229,294	6,459,453	367,734	6,091,719	4,568,703	1,083,105	351,717	88,194	133,001
14	Deducts: Accum Defer Inc Tax		2,008,583	849,766	1,139,763	60,993	1,078,769	806,235	191,590	64,594	16,351	19,055
15	Constr Work In Progress		532,577	219,204	311,105	15,549	295,557	220,823	52,855	17,610	4,268	2,268
16	Fuel Inventory		84,026	26,505	57,224	2,496	54,727	39,767	9,754	4,241	965	297
17	Materials & Supplies		152,207	54,660	96,879	4,487	92,392	67,854	16,452	6,558	1,529	668
18	Prepayments		97,879	43,296	53,482	3,045	50,437	37,827	8,968	2,912	730	1,101
19	Non-Plant & Work Cash		(23,619)	(21,536)	(1,710)	(1,089)	(621)	(1,485)	12	762	91	(372)
20	Total Additions		843,070	322,130	516,979	24,487	492,492	364,785	88,040	32,083	7,583	3,962
21	**Rate Base**		10,656,235	4,701,659	5,836,669	331,228	5,505,441	4,127,253	979,555	319,206	79,427	117,908

Income Statement

			MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
22A	**Tot Oper Rev - Pres**		3,599,829	1,392,621	2,178,350	120,152	2,058,198	1,552,033	336,661	133,476	36,028	28,858
22B	**Tot Oper Rev - Prop**		4,197,185	1,646,129	2,515,880	135,097	2,380,783	1,794,933	391,214	153,192	41,444	35,176
23	Oper & Maint		2,449,128	910,791	1,521,980	74,379	1,447,601	1,068,774	256,591	98,665	23,571	16,358
24	Book Depr + IRS Int		792,829	329,549	454,518	24,567	429,951	319,963	76,191	27,249	6,548	8,761
25	Payroll, Rl Est & Prop Tax		242,156	107,957	131,540	7,581	123,959	93,061	21,980	7,143	1,774	2,659
26	Deferred Inc Tax & Net ITC		(147,115)	(63,858)	(81,328)	(4,478)	(76,850)	(57,451)	(13,590)	(4,672)	(1,137)	(1,929)
27A	Present Income Tax		(61,484)	(28,098)	(33,041)	902	(33,943)	(17,460)	(14,174)	(2,765)	454	(345)
27B	Proposed Income Tax		110,208	44,765	63,972	5,198	58,774	52,354	1,506	2,902	2,011	1,471
28	Allow Funds Dur Const		31,124	12,597	18,406	923	17,483	13,061	3,119	1,049	254	120
29A	**Present Return**		355,438	148,877	203,087	18,124	184,963	158,207	12,780	8,903	5,072	3,473
29B	**Proposed Return**		781,102	329,522	443,604	28,773	414,831	331,293	51,654	22,953	8,932	7,976
30A	**Pres Ret on Rt Base**		3.34%	3.17%	3.48%	5.47%	3.36%	3.83%	1.30%	2.79%	6.39%	2.95%
30B	**Prop Ret on Rt Base**		**7.33%**	7.01%	7.60%	8.69%	7.53%	8.03%	5.27%	7.19%	11.25%	6.76%
31A	**Pres Ret on Common**		2.60%	2.28%	2.88%	6.67%	2.65%	3.55%	-1.27%	1.56%	8.41%	1.86%
31B	**Prop Ret on Common**		**10.21%**	9.60%	10.72%	12.79%	10.60%	11.54%	6.29%	9.94%	17.67%	9.13%

Northern States Power Company

2023 Class Cost of Service Detail ($000)

PRES vs Equal Rev Reqts

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**UnAdj Equal Rev Reqt @ 7.33%**		**3,626,179**	**1,458,002**	**2,133,572**	**112,483**	**2,021,089**	**1,501,422**	**358,284**	**129,888**	**31,496**	**34,605**
2	**Present Revenue**		**3,030,677**	**1,184,879**	**1,818,446**	**103,902**	**1,714,543**	**1,299,069**	**275,479**	**109,551**	**30,445**	**27,353**
3	**UnAdj Revenue Deficiency**		**595,502**	**273,123**	**315,126**	**8,580**	**306,546**	**202,353**	**82,806**	**20,337**	**1,051**	**7,252**
4	**UnAdj Deficiency / Present**		**19.65%**	**23.05%**	**17.33%**	**8.26%**	**17.88%**	**15.58%**	**30.06%**	**18.56%**	**3.45%**	**26.51%**
			[PROTECTED DATA 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**										
											PROTECTED DATA ENDS]	
9	**Revenue Requirement Shift**		**0**	**(2,103)**	**2,098**	**778**	**1,319**	**7,485**	**(3,607)**	**(2,754)**	**195**	**6**
10	**Adj Equal Rev Reqt (Rows 1+9)**		**3,626,179**	**1,455,899**	**2,135,670**	**113,261**	**2,022,409**	**1,508,907**	**354,677**	**127,134**	**31,690**	**34,611**
11	**Adj Rev Defic vs Pres Rev (Row 2)**		**595,502**	**271,020**	**317,224**	**9,359**	**307,865**	**209,838**	**79,198**	**17,583**	**1,245**	**7,258**
12	**Adj Deficiency / Adj Present**		**19.65%**	**22.87%**	**17.44%**	**9.01%**	**17.96%**	**16.15%**	**28.75%**	**16.05%**	**4.09%**	**26.54%**
	Equal Customer Classification											
13	Min Sys & Service Drop		284,363	232,653	26,080	15,508	10,571	10,354	209	5	2	25,630
14	Energy Services		38,029	32,026	5,847	3,002	2,845	2,791	52	2	1	157
15	Total Customer **(Cusco)**		322,392	264,679	31,926	18,510	13,416	13,145	261	7	4	25,787
16	Ave Monthly Customers		1,359,826	1,195,411	136,291	87,068	49,223	48,728	473	13	9	28,124
17	Svc Drop Reqt	$ / Mo / Cust	$17.43	$16.22	$15.95	$14.84	$17.90	$17.71	$36.84	$31.88	$21.50	$75.94
18	Ener Svcs Reqt	$ / Mo / Cust	$2.33	$2.23	$3.58	$2.87	$4.82	$4.77	$9.09	$12.29	$11.23	$0.46
19	Total Reqt	$ / Mo / Cust	$19.76	$18.45	$19.52	$17.72	$22.71	$22.48	$45.94	$44.17	$32.73	$76.41
	Equal Energy Classification											
20	On Peak Rev Reqt		812,233	247,387	563,509	25,670	537,839	397,231	94,204	37,287	9,118	1,337
21	Off Peak Rev Reqt		836,011	272,088	559,279	23,394	535,884	385,953	96,241	43,668	10,022	4,644
22	Total Ener Rev Reqt		1,648,243	519,475	1,122,788	49,064	1,073,724	783,184	190,444	80,956	19,140	5,980
23	Annual MWh Sales		27,357,999.624	8,458,905	18,777,113	797,613	17,979,500	12,890,479	3,259,279	1,494,404	335,338	121,981
24	On Pk Reqt	Mills / kWh	29.689	29.246	30.010	32.183	29.914	30.816	28.903	24.951	27.190	10.957
25	Off Pk Reqt	Mills / kWh	30.558	32.166	29.785	29.331	29.805	29.941	29.528	29.221	29.888	38.070
26	Total Reqt	Mills / kWh	60.247	61.412	59.796	61.514	59.719	60.757	58.431	54.173	57.077	49.027
	Equal Demand Classification											
27	Energy-Related Prod		426,648	138,584	286,695	12,532	274,163	199,778	48,851	20,775	4,759	1,368
28	Capacity-Related Summer Peak Prod		316,208	132,856	183,352	8,258	175,094	131,623	31,219	9,816	2,436	0
29	Capacity-Related Winter Peak Prod		93,498	39,283	54,214	2,442	51,773	38,919	9,231	2,902	720	0
30	Total Capacity-Related Prod		409,706	172,139	237,567	10,700	226,867	170,542	40,450	12,719	3,156	0
31	Total Production		836,355	310,724	524,262	23,232	501,030	370,320	89,301	33,494	7,915	1,368
32	Transmission **(Transco)**		493,371	207,055	286,316	12,865	273,450	205,105	48,620	15,288	4,437	0
33	Primary Dist Subs		93,770	39,063	54,167	2,779	51,388	40,921	10,324	143	0	539
34	Prim Dist Lines		200,368	100,184	99,323	5,134	94,189	74,855	19,334	0	0	861
35	Second Dist, Trans		31,681	16,822	14,790	898	13,891	13,891	0	0	0	69
36	Total Distribution **(Disco)**		325,818	156,069	168,280	8,811	159,469	129,668	29,658	143	0	1,470
37	Total Demand Rev Reqt		1,655,543	673,848	978,857	44,908	933,949	705,093	167,579	48,925	12,352	2,838
38	Annual Billing kW		47,111,052	0	47,111,052	0	47,111,052	36,287,566	7,178,865	2,699,759	944,862	0
39	Base Rev Reqt	$ / kW	$0.00	$0.00	$6.09	$0.00	$5.82	$5.51	$6.80	$7.70	$5.04	$0.00
40	Summer Rev Reqt	$ / kW	$0.00	$0.00	$3.89	$0.00	$3.72	$3.63	$4.35	$3.64	$2.58	$0.00
41	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.15	$0.00	$1.10	$1.07	$1.29	$1.08	$0.76	$0.00
42	Prod Rev Reqt	$ / kW	$0.00	$0.00	$11.13	$0.00	$10.64	$10.21	$12.44	$12.41	$8.38	$0.00
43	Tran Rev Reqt	$ / kW	$0.00	$0.00	$6.08	$0.00	$5.80	$5.65	$6.77	$5.66	$4.70	$0.00
44	Dist Rev Reqt	$ / kW	$0.00	$0.00	$3.57	$0.00	$3.38	$3.57	$4.13	$0.05	$0.00	$0.00
45	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$20.78	$0.00	$19.82	$19.43	$23.34	$18.12	$13.07	$0.00
46	Tot Dmd Rev Reqt	Mills / kWh	60.514	79.661	52.130	56.303	51.945	54.699	51.416	32.739	36.834	23.266
47	Summer Billing kW		17,357,236	0	17,357,236	0	17,357,236	13,350,214	2,693,778	935,433	377,811	0
48	Winter Billing kW		29,753,816	0	29,753,816	0	29,753,816	22,937,351	4,485,087	1,764,326	567,052	0
49	Tot Summer Reqt	$ / kW	$0.00	$0.00	$26.30	$0.00	$25.10	$24.59	$29.30	$23.90	$16.18	$0.00
50	Tot Winter Reqt	$ / kW	$0.00	$0.00	$17.56	$0.00	$16.75	$16.43	$19.77	$15.06	$11.00	$0.00
51	Energy + Production **(Genco)**		2,484,598	830,199	1,647,050	72,296	1,574,754	1,153,504	279,745	114,450	27,055	7,349

Northern States Power Company

2023 Class Cost of Service Detail ($000)

PROP vs Equal Rev Reqts

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**Proposed Ret On Rt Base**		**7.33%**	**7.01%**	**7.60%**	**8.69%**	**7.53%**	**8.03%**	**5.27%**	**7.19%**	**11.25%**	**6.76%**
2	**UnAdj Equalized Rev Reqt**		**3,626,179**	**1,458,002**	**2,133,572**	**112,483**	**2,021,089**	**1,501,422**	**358,284**	**129,888**	**31,496**	**34,605**
3	**Proposed Revenue**		**3,626,179**	**1,436,798**	**2,155,712**	**118,789**	**2,036,922**	**1,541,789**	**330,010**	**129,263**	**35,860**	**33,669**
4	**UnAdj Revenue Deficiency**		**0**	**21,204**	**(22,140)**	**(6,307)**	**(15,833)**	**(40,367)**	**28,274**	**624**	**(4,364)**	**936**
5	**UnAdj Deficiency / Proposed**		**0.00%**	**1.48%**	**-1.03%**	**-5.31%**	**-0.78%**	**-2.62%**	**8.57%**	**0%**	**-12%**	**2.78%**
			[PROTECTED DATA 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**										
											PROTECTED DATA ENDS]	
10	**Revenue Requirement Shift**		**0**	**4,342**	**(4,350)**	**557**	**(4,907)**	**3,218**	**(5,028)**	**(3,212)**	**115**	**7**
11	**Adj Equal Rev (Rows 2+10)**		**3,626,179**	**1,462,344**	**2,129,222**	**113,039**	**2,016,183**	**1,504,639**	**353,257**	**126,676**	**31,611**	**34,612**
12	**Adj Rev Defic vs Prop Rev (Row 3)**		**0**	**25,546**	**(26,489)**	**(5,750)**	**(20,740)**	**(37,150)**	**23,246**	**(2,587)**	**(4,249)**	**943**
13	**Adj Deficiency / Adj Prop**		**0.00%**	**1.78%**	**-1.23%**	**-4.84%**	**-1.02%**	**-2.41%**	**7.04%**	**-2.00%**	**-11.85%**	**2.80%**
	Prop Customer Component											
14	Min Sys & Service Drop		277,794	225,331	27,645	16,733	10,913	10,712	193	5	3	24,818
15	Energy Services		38,041	32,041	5,843	2,999	2,845	2,790	52	2	1	157
16	Total Customer **(Cusco)**		315,835	257,372	33,489	19,731	13,757	13,502	245	7	4	24,975
17	Ave Monthly Customers		1,359,826	1,195,411	136,291	87,068	49,223	48,728	473	13	9	28,124
18	Svc Drop Reqt	$ / Mo / Cust	$17.02	$15.71	$16.90	$16.01	$18.47	$18.32	$33.95	$32.11	$24.76	$73.54
19	Ener Svcs Reqt	$ / Mo / Cust	$2.33	$2.23	$3.57	$2.87	$4.82	$4.77	$9.11	$12.30	$11.19	$0.46
20	Total Reqt	$ / Mo / Cust	$19.36	$17.94	$20.48	$18.89	$23.29	$23.09	$43.06	$44.40	$35.96	$74.00
	Prop Energy Component											
21	On Peak Rev Reqt		812,020	247,213	563,471	25,703	537,768	397,411	93,935	37,266	9,156	1,336
22	Off Peak Rev Reqt		835,762	271,896	559,226	23,424	535,802	386,127	95,966	43,643	10,065	4,640
23	Total Ener Rev Reqt		1,647,783	519,109	1,122,698	49,127	1,073,570	783,538	189,901	80,909	19,222	5,976
24	Annual MWh Sales		27,358,000	8,458,905	18,777,113	797,613	17,979,500	12,890,479	3,259,279	1,494,404	335,338	121,981
25	On Pk Reqt	Mills / kWh	29.681	29.225	30.008	32.225	29.910	30.830	28.821	24.937	27.305	10.950
26	Off Pk Reqt	Mills / kWh	30.549	32.143	29.782	29.368	29.801	29.954	29.444	29.204	30.015	38.040
27	Total Reqt	Mills / kWh	60.230	61.368	59.791	61.593	59.711	60.784	58.265	54.141	57.320	48.989
	Prop Demand Component											
28	Energy-Related Prod		430,769	133,715	295,755	14,802	280,953	217,748	35,643	20,334	7,229	1,299
29	Capacity-Related Summer Peak Prod		317,855	131,963	185,891	8,738	177,154	135,695	28,847	9,797	2,815	0
30	Capacity-Related Winter Peak Prod		93,985	39,020	54,965	2,584	52,382	40,123	8,529	2,897	832	0
31	Total Capacity-Related Prod		411,839	170,983	240,857	11,321	229,535	175,818	37,376	12,693	3,648	0
32	Total Production		842,608	304,698	536,611	26,123	510,488	393,566	73,019	33,027	10,876	1,299
33	Transmission **(Transco)**		497,585	204,150	293,434	14,230	279,204	216,545	41,693	15,208	5,758	0
34	Primary Dist Subs		93,600	38,164	54,912	3,078	51,833	43,092	8,630	112	0	524
35	Prim Dist Lines		197,168	97,068	99,270	5,529	93,740	77,217	16,523	0	0	830
36	Second Dist, Trans		31,601	16,236	15,299	970	14,329	14,329	0	0	0	66
37	Total Distribution **(Disco)**		322,368	151,468	169,480	9,577	159,903	134,638	25,152	112	0	1,420
38	Total Demand Rev Reqt		1,662,561	660,317	999,525	49,930	949,595	744,749	139,864	48,347	16,634	2,719
39	Annual Billing kW		47,111,052	0	47,111,052	0	47,111,052	36,287,566	7,178,865	2,699,759	944,862	0
40	Base Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$5.96	$6.00	$4.96	$7.53	$7.65	$0.00
41	Summer Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$3.76	$3.74	$4.02	$3.63	$2.98	$0.00
42	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$1.11	$1.11	$1.19	$1.07	$0.88	$0.00
43	Prod Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$10.84	$10.85	$10.17	$12.23	$11.51	$0.00
44	Tran Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$5.93	$5.97	$5.81	$5.63	$6.09	$0.00
45	Dist Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$3.39	$3.71	$3.50	$0.04	$0.00	$0.00
46	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$20.16	$20.52	$19.48	$17.91	$17.61	$0.00
47	Tot Dmd Rev Reqt	Mills / kWh	60.771	78.062	53.231	62.600	52.815	57.775	42.913	32.352	49.605	22.288
48	Summer Billing kW		17,357,236	0	17,357,236	0	17,357,236	13,350,214	2,693,778	935,433	377,811	0
49	Winter Billing kW		29,753,816	0	29,753,816	0	29,753,816	22,937,351	4,485,087	1,764,326	567,052	0
50	Tot Summer Reqt	$ / kW	$0.00	$0.00	$26.81	$0.00	$25.49	$25.84	$24.98	$23.68	$21.20	$0.00
51	Tot Winter Reqt	$ / kW	$0.00	$0.00	$17.95	$0.00	$17.04	$17.43	$16.18	$14.85	$15.21	$0.00
52	Energy + Production **(Genco)**		2,490,391	823,807	1,659,309	75,250	1,584,059	1,177,104	262,920	113,936	30,098	7,274
53	Prop Rev - Pres Rev (Pg 2)		595,502	251,919	337,266	14,887	322,379	242,720	54,531	19,713	5,415	6,316
54	Difference / Present		19.65%	21.26%	18.55%	14.33%	18.80%	18.68%	19.80%	17.99%	17.79%	23.09%

Northern States Power Company

2023 Class Cost of Service Detail ($000)

Original Plant in Service

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Summer Peak	D10S		1,953,428	822,409	1,131,019	51,000	1,080,020	811,923	192,553	60,527	15,017	0
2	WInter Peak	D10S		577,598	243,173	334,425	15,080	319,345	240,073	56,935	17,897	4,440	0
3	Total Peak	D10S		2,531,026	1,065,582	1,465,444	66,079	1,399,365	1,051,996	249,488	78,424	19,458	0
4	Base Load	E8760		7,127,897	2,248,446	4,854,262	211,765	4,642,497	3,373,415	827,449	359,744	81,890	25,188
5	Nuclear Fuel	E8760		2,732,570	861,970	1,860,943	81,183	1,779,760	1,293,241	317,213	137,912	31,393	9,656
6	Total	26.20%	120, 310-346	12,391,493	4,175,999	8,180,650	359,027	7,821,622	5,718,652	1,394,149	576,081	132,741	34,845
	Transmission												
7	Gen Step Up Base	E8760		97,877	30,875	66,657	2,908	63,749	46,322	11,362	4,940	1,124	346
8	Gen Step Up Peak	D10S		36,993	15,575	21,419	966	20,453	15,376	3,647	1,146	284	0
9	Total Gen Step Up			134,871	46,449	88,076	3,874	84,202	61,698	15,009	6,086	1,409	346
10	Bulk Transmission	D10S		3,600,448	1,515,817	2,084,631	94,000	1,990,632	1,496,490	354,902	111,560	27,679	0
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		8,613	0	8,613	0	8,613	948	0	0	7,665	0
13	Total		350-359	3,743,932	1,562,266	2,181,320	97,873	2,083,447	1,559,136	369,911	117,646	36,753	346
	Distribution:												
	Substations												
14	Generat Step Up	STRATH		3,046	1,015	2,022	89	1,933	1,412	345	144	33	9
15	Bulk Transmission	D10S		1,910	804	1,106	50	1,056	794	188	59	15	0
16	Distrib Function	D60Sub		779,962	333,761	441,606	23,698	417,907	348,211	81,000	(11,304)	0	4,595
17	Direct Assign	Dir Assign		20,107,951	0	20,108	0	20,108	438	7,033	12,636	0	0
18	Total		360-363	805,026	335,580	464,841	23,837	441,004	350,855	88,566	1,535	48	4,604
	Overhead Lines												
19	Primary Capacity 1 Phase	D61PS1Ph		195,081	146,047	47,888	5,405	42,483	32,450	10,033	0	0	1,146
20	Primary Capacity Multi Phase	D61PS		419,730	153,653	264,638	10,271	254,367	203,688	50,679	0	0	1,440
21	Primary Customer 1 Phase	C61PS1Ph		104,652	99,538	4,708	4,017	690	682	8	0	0	406
22	Primary Customer Multi Phase	C61PS		225,165	201,210	22,974	14,667	8,307	8,227	80	0	0	981
23	Total Primary			944,628	600,447	340,208	34,360	305,848	245,047	60,800	0	0	3,973
24	Second Capacity	D62SecL		48,009	23,382	24,500	1,452	23,048	23,048	0	0	0	127
25	Second Customer	C62Sec		172,728	154,406	17,569	11,256	6,313	6,313	0	0	0	753
26	Total Secondary			220,737	177,788	42,069	12,707	29,361	29,361	0	0	0	880
27	Street Lighting	DASL		58,777	0	0	0	0	0	0	0	0	58,777
28	Total		364,365	1,224,142	778,235	382,276	47,067	335,209	274,409	60,800	0	0	63,630
	Underground Lines												
29	Primary Capacity 1 Phase	D61PS1Ph		302,834	226,716	74,339	8,390	65,949	50,374	15,575	0	0	1,779
30	Primary Capacity Multi Phase	D61PS		435,252	159,335	274,424	10,651	263,774	211,220	52,553	0	0	1,493
31	Primary Customer 1 Phase	C61PS1Ph		344,151	327,333	15,481	13,211	2,270	2,243	27	0	0	1,337
32	Primary Customer Multi Phase	C61PS		494,635	442,010	50,470	32,221	18,249	18,073	176	0	0	2,155
33	Total Primary			1,576,873	1,155,395	414,714	64,472	350,242	281,911	68,331	0	0	6,764
34	Second Capacity	D62SecL		50,729	24,707	25,888	1,534	24,354	24,354	0	0	0	135
35	Second Customer	C62Sec		142,613	127,485	14,506	9,293	5,213	5,213	0	0	0	622
36	Total Secondary			193,342	152,192	40,394	10,827	29,567	29,567	0	0	0	756
37	Street Lighting	DASL		0	0	0	0	0	0	0	0	0	0
38	Total		366,367	1,770,215	1,307,587	455,108	75,299	379,809	311,478	68,331	0	0	7,520
	Line Transformers												
39	Primary	D61PS		42,955	15,725	27,083	1,051	26,032	20,846	5,187	0	0	147
40	Second Capacity	D62SecL		128,241	62,458	65,443	3,877	61,566	61,566	0	0	0	340
41	Second Customer	C62Sec		225,206	201,317	22,907	14,675	8,232	8,232	0	0	0	982
42	Total		368	396,403	279,500	115,433	19,604	95,830	90,643	5,187	0	0	1,469
	Services												
43	Second Capacity	D62NLL		69,528	50,909	18,619	1,378	17,241	17,241	0	0	0	0
44	Second Customer	C62NL		218,700	207,762	10,938	7,007	3,930	3,930	0	0	0	0
43	Total Services	C62NL	369	288,228	258,671	29,557	8,386	21,171	21,171	0	0	0	0
44	Meters	C12WM	370	117,873	81,502	36,105	12,245	23,860	22,750	1,064	31	15	266
45	Street Lighting	Dir Assign	373	71,880	0	0	0	0	0	0	0	0	71,880
46	**Total Distribution**			4,673,765	3,041,076	1,483,321	186,438	1,296,883	1,071,305	223,948	1,566	63	149,369
47	**General & Common Plant**	PTD	303, 389-399	2,257,788	952,555	1,285,209	69,802	1,215,407	905,873	215,698	75,439	18,397	20,025
48	Prelim Elec Plant			23,066,979	9,731,895	13,130,499	713,141	12,417,358	9,254,966	2,203,706	770,732	187,953	204,585
49	TBT Investment	NEPIS		0	0	0	0	0	0	0	0	0	0
50	**Elec Plant in Serv**			23,066,979	9,731,895	13,130,499	713,141	12,417,358	9,254,966	2,203,706	770,732	187,953	204,585

Northern States Power Company

2023 Class Cost of Service Detail ($000)

Accum Deprec; Net Plant

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		1,468,253	618,146	850,107	38,333	811,774	610,265	144,728	45,494	11,287	0
2	Decom Int Peaking	D10S		0	0	0	0	0	0	0	0	0	0
3	Decom Int Baseload	E8760		0	0	0	0	0	0	0	0	0	0
4	Nuclear Fuel	E8760		2,567,215	809,810	1,748,333	76,270	1,672,062	1,214,984	298,018	129,567	29,494	9,072
5	Base Load	E8760		3,475,642	1,096,368	2,366,992	103,259	2,263,733	1,644,915	403,473	175,415	39,930	12,282
6	Total		108,111,115,120.5	7,511,111	2,524,324	4,965,432	217,862	4,747,570	3,470,163	846,219	350,476	80,712	21,354
	Transmission												
7	Gen Step Up Base	E8760		13,680	4,315	9,317	406	8,910	6,474	1,588	690	157	48
8	Gen Step Up Peak	D10S		16,292	6,859	9,433	425	9,008	6,772	1,606	505	125	0
9	Total Gen Step Up			29,973	11,175	18,750	832	17,918	13,246	3,194	1,195	282	48
10	Bulk Transmission	D10S		865,636	364,440	501,196	22,600	478,597	359,793	85,327	26,822	6,655	0
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		2,686	0	2,686	0	2,686	296	0	0	2,390	0
13	Total		108,111,115,120.5	898,294	375,614	522,632	23,432	499,200	373,335	88,521	28,017	9,327	48
	Distribution												
14	Generat Step Up	STRATH		2,391	797	1,587	70	1,517	1,108	270	113	26	7
15	Bulk Transmission	D10S		670	282	388	18	371	279	66	21	5	0
16	Distrib Function	D60Sub		251,677	107,697	142,497	7,647	134,850	112,360	26,137	(3,648)	0	1,483
17	Direct Assign	Dir Assign		6,876	0	6,876	0	6,876	150	2,405	4,321	0	0
18	Total Substations			261,615	108,777	151,348	7,734	143,614	113,897	28,879	807	31	1,490
19	Overhead Lines	POL		401,083	254,984	125,251	15,421	109,829	89,908	19,921	0	0	20,848
20	Underground	PUL		532,775	393,540	136,972	22,662	114,310	93,744	20,565	0	0	2,263
21	Line Transformers	P68		181,467	127,951	52,844	8,974	43,869	41,495	2,374	0	0	673
22	Services	P69		188,072	168,786	19,286	5,472	13,814	13,814	0	0	0	0
23	Meters	C12WM		68,523	47,380	20,989	7,119	13,870	13,225	619	18	8	155
24	Street Lighting	P73		14,216	0	0	0	0	0	0	0	0	14,216
25	Total		108,111,115,120.5	1,647,751	1,101,417	506,690	67,382	439,307	366,084	72,358	825	40	39,644
26	**General & CommonPlant**	PTD	108,111,115,120.5	1,188,076	501,246	676,293	36,731	639,562	476,681	113,503	39,697	9,681	10,537
27	**Total Accum Depr**			11,245,231	4,502,601	6,671,046	345,407	6,325,639	4,686,264	1,120,601	419,016	99,759	71,584
28	**Net Elec Plant**			11,821,748	5,229,294	6,459,453	367,734	6,091,719	4,568,703	1,083,105	351,717	88,194	133,001
29	**Net Plant w/ TBT**			11,821,748	5,229,294	6,459,453	367,734	6,091,719	4,568,703	1,083,105	351,717	88,194	133,001

Subtractions: Accum Defer Inc Tax

				MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
	Production												
30	Peaking Plant	D10S		256,045	107,797	148,248	6,685	141,563	106,422	25,239	7,934	1,968	0
31	Base Load	E8760		975,487	307,711	664,329	28,981	635,348	461,668	113,240	49,233	11,207	3,447
32	Nuclear Fuel	E8760		(8,394)	(2,648)	(5,717)	(249)	(5,467)	(3,973)	(974)	(424)	(96)	(30)
33	Total		190,281,282,283	1,223,138	412,860	806,860	35,416	771,444	564,118	137,505	56,743	13,079	3,418
	Transmission												
34	Gen Step Up Base	E8760		17,559	5,539	11,958	522	11,437	8,310	2,038	886	202	62
35	Gen Step Up Peak	D10S		4,674	1,968	2,706	122	2,584	1,943	461	145	36	0
36	Total Gen Step Up			22,234	7,507	14,665	644	14,021	10,253	2,499	1,031	238	62
37	Bulk Transmission	D10S		732,870	308,544	424,326	19,134	405,193	304,610	72,240	22,708	5,634	0
38	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
39	Direct Assign	Dir Assign		1,604	0	1,604	0	1,604	177	0	0	1,428	0
40	Total		281,282,283	756,708	316,051	440,595	19,777	420,818	315,040	74,739	23,739	7,299	62
	Distribution												
41	Generat Step Up	STRATH		271	90	180	8	172	126	31	13	3	1
42	Bulk Transmission	D10S		237	100	137	6	131	99	23	7	2	0
43	Distrib Function	D60Sub		110,619	47,336	62,631	3,361	59,270	49,385	11,488	(1,603)	0	652
44	Direct Assign	Dir Assign		2,438	0	2,438	0	2,438	53	853	1,532	0	0
45	Total Substations			113,564	47,526	65,386	3,375	62,011	49,663	12,395	(51)	5	653
46	Overhead Lines	POL		154,365	98,136	48,205	5,935	42,270	34,603	7,667	0	0	8,024
47	Underground	PUL		230,858	170,526	59,352	9,820	49,532	40,621	8,911	0	0	981
48	Line Transformers	P68		53,059	37,411	15,451	2,624	12,827	12,133	694	0	0	197
49	Services	P69		15,001	13,463	1,538	436	1,102	1,102	0	0	0	0
50	Meters	C12WM		11,560	7,993	3,541	1,201	2,340	2,231	104	3	1	26
51	Street Lighting	P73		12,398	0	0	0	0	0	0	0	0	12,398
52	Total		281,282,283	590,806	375,055	193,473	23,392	170,081	140,352	29,771	(48)	6	22,278
53	**General & Common Plant**	PTD	281,282,283	142,558	60,145	81,149	4,407	76,741	57,197	13,619	4,763	1,162	1,264
54	**Total Deferred Tax**			2,713,209	1,164,110	1,522,077	82,993	1,439,084	1,076,707	255,635	85,197	21,546	27,022
55	Net Operating Loss (NOL) Carry F	NEPIS		(746,010)	(329,994)	(407,623)	(23,206)	(384,417)	(288,307)	(68,349)	(22,195)	(5,565)	(8,393)
56	Non-Plant Related	LABOR		41,384	15,649	25,309	1,207	24,102	17,835	4,305	1,592	370	426
57	**Accum Def W/ Adj**			2,008,583	849,766	1,139,763	60,993	1,078,769	806,235	191,590	64,594	16,351	19,055

Northern States Power Company

2023 Class Cost of Service Detail ($000)

Additions: CWIP, Etc; Rate Base

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		71,938	30,287	41,652	1,878	39,774	29,900	7,091	2,229	553	0
2	Base Load	E8760		73,013	23,031	49,723	2,169	47,554	34,555	8,476	3,685	839	258
3	Nuclear Fuel	E8760		80,423	25,369	54,770	2,389	52,381	38,062	9,336	4,059	924	284
4	Total		107	225,374	78,687	146,145	6,437	139,709	102,517	24,903	9,973	2,316	542
	Transmission												
5	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10S		0	0	0	0	0	0	0	0	0	0
7	Total Gen Step Up			0	0	0	0	0	0	0	0	0	0
8	Bulk Transmission	D10S		159,802	67,278	92,524	4,172	88,352	66,420	15,752	4,951	1,229	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
11	Total		107	159,802	67,278	92,524	4,172	88,352	66,420	15,752	4,951	1,229	0
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		19,572	8,375	11,082	595	10,487	8,738	2,033	(284)	0	115
15	Direct Assign	Dir Assign		1	0	1	0	1	0	0	0	0	0
16	Total Substations			19,573	8,375	11,082	595	10,488	8,738	2,033	(283)	0	115
17	Overhead Lines	POL		13,740	8,735	4,291	528	3,763	3,080	682	0	0	714
18	Underground	PUL		25,992	19,200	6,682	1,106	5,577	4,573	1,003	0	0	110
19	Line Transformers	P68		(670)	(472)	(195)	(33)	(162)	(153)	(9)	0	0	(2)
20	Services	P69		(101)	(91)	(10)	(3)	(7)	(7)	0	0	0	0
21	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
23	Total		107	58,535	35,747	21,850	2,193	19,658	16,231	3,710	(283)	0	937
24	**General & Common Plant**	PTD	107	88,866	37,492	50,585	2,747	47,838	35,655	8,490	2,969	724	788
25	**Total CWIP**			532,577	219,204	311,105	15,549	295,557	220,823	52,855	17,610	4,268	2,268
26	Fuel Inventory	E8760	151,152	84,026	26,505	57,224	2,496	54,727	39,767	9,754	4,241	965	297
	Materials & Supplies												
27	Production	P10		136,170	45,890	89,897	3,945	85,952	62,842	15,320	6,331	1,459	383
28	Trans & Distr	TD		16,036	8,770	6,981	542	6,440	5,011	1,131	227	70	285
29	Total		154	152,207	54,660	96,879	4,487	92,392	67,854	16,452	6,558	1,529	668
	Prepayments												
30	Miscellaneous	NEPIS		97,879	43,296	53,482	3,045	50,437	37,827	8,968	2,912	730	1,101
31	Fuel	E8760		0	0	0	0	0	0	0	0	0	0
32	Insurance	NEPIS	135,143,184,186,232	0	0	0	0	0	0	0	0	0	0
33	Total		235,252,165	97,879	43,296	53,482	3,045	50,437	37,827	8,968	2,912	730	1,101
34	Non-Plant Assets & Liab	LABOR	190,283,	140,883	53,275	86,159	4,107	82,052	60,717	14,655	5,419	1,260	1,449
35	Working Cash	PT0	calculated	(164,501)	(74,811)	(87,869)	(5,197)	(82,672)	(62,202)	(14,643)	(4,657)	(1,170)	(1,821)
36	**Total Additions**			843,070	322,130	516,979	24,487	492,492	364,785	88,040	32,083	7,583	3,962
37	**Total Rate Base**			10,656,235	4,701,659	5,836,669	331,228	5,505,441	4,127,253	979,555	319,206	79,427	117,908
38	**Common Rate Base (@ 52.50%)**			5,594,523.5	2,468,371	3,064,251	173,895	2,890,357	2,166,808	514,266	167,583	41,699	61,902

Northern States Power Company

2023 Class Cost of Service Detail ($000)

Operating Rev (Cal Month)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Retail Revenue	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Present Rate Revenue	R01; (calc)	440, 442,444,445	3,030,677	1,184,879	1,818,446	103,902	1,714,543	1,299,069	275,479	109,551	30,445	27,353
2	Proposed Rate Revenue	PROREV; (calc)		3,626,179	1,436,798	2,155,712	118,789	2,036,922	1,541,789	330,010	129,263	35,860	33,669
3	Equal Rate Revenue			3,626,179	1,458,002	2,133,572	112,483	2,021,089	1,501,422	358,284	129,888	31,496	34,605
	Other Retail Revenue												
4	Interdepartmental	R01; R02	448	686	268	411	24	388	294	62	25	7	6
5	Gross Earnings Tax	R01; R02	408	0	0	0	0	0	0	0	0	0	0
6	CIP Adjustment to Program Costs	E99XCIP	456	0	0	0	0	0	0	0	0	0	0
7	**Tot Other Retail Rev**			686	268	411	24	388	294	62	25	7	6
	Other Operating Revenue												
8	Interchg Prod Capacity	P10	456	428,389	144,369	282,815	12,412	270,403	197,701	48,197	19,916	4,589	1,205
9	Interchg Prod Energy	E8760	456	0	0	0	0	0	0	0	0	0	0
10	Interchg Tr Bulk Supply	D10S	456	0	0	0	0	0	0	0	0	0	0
11	Dist Int Sales; Oth Serv	E8760	412,451,456	1,005	317	685	30	655	476	117	51	12	4
12	Dist Overhd Line Rent	POL	454	4,760	3,026	1,487	183	1,304	1,067	236	0	0	247
13	Connection Charges	C11	451	1,923	1,691	193	123	70	69	1	0	0	40
14	Sales For Resale	E8760	447	0	0	0	0	0	0	0	0	0	0
15	Joint Op Agree-Other PSCo Rev	D10S	456	0	0	0	0	0	0	0	0	0	0
16	Misc Ancillary Trans Rev	D10S		215,853	90,876	124,977	5,635	119,342	89,717	21,277	6,688	1,659	0
17	MISO	D10S	456	(94,412)	(39,748)	(54,664)	(2,465)	(52,199)	(39,241)	(9,306)	(2,925)	(726)	0
18	Other	D10S	451,456,457	5,499	2,315	3,184	144	3,040	2,286	542	170	42	0
19	Late Pay Chg - Pres	R16C; R02		5,448	4,628	817	164	653	597	56	0	0	3
20	**Tot Other Op - Pres**		450	568,466	207,475	359,493	16,226	343,267	252,670	61,119	23,900	5,577	1,499
21	Incr Misc Serv - Prop	C62NL		667	633	33	21	12	12	0	0	0	0
22	Incr Inter-Dept'l - Prop	R01; R02		117	46	70	4	66	50	11	4	1	1
23	Incr Late Pay - Prop	(R16C); R02		1,071	909	160	32	128	117	11	0	0	1
	Tot Incr Other Op			1,854	1,588	264	58	206	179	22	4	1	2
24	**Tot Other Op - Prop**			570,320	209,063	359,757	16,284	343,473	252,850	61,141	23,904	5,578	1,501
25	**Tot Oper Rev - Pres**			3,599,829	1,392,621	2,178,350	120,152	2,058,198	1,552,033	336,661	133,476	36,028	28,858
26	**Tot Oper Rev - Prop**			4,197,185	1,646,129	2,515,880	135,097	2,380,783	1,794,933	391,214	153,192	41,444	35,176
	Tot Oper Rev - Eql			4,197,185	1,667,333	2,493,740	128,790	2,364,950	1,754,565	419,488	153,817	37,080	36,112

Operating & Maint (Pg 1 of 2)

				MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
	Production Expen												
27	**Fuel**	E8760	501,518,547	621,092	195,919	422,978	18,452	404,526	293,944	72,100	31,346	7,135	2,195
	Purchased Power												
28	Purchases: Cap Peak	D10S		104,628	44,049	60,579	2,732	57,847	43,488	10,313	3,242	804	0
29	Purchases: Cap Base	D10S		38,934	16,391	22,542	1,016	21,526	16,182	3,838	1,206	299	0
30	Purchases: Demand		555	143,562	60,441	83,121	3,748	79,373	59,670	14,151	4,448	1,104	0
31	Purchases: Other Energy	E8760	555	299,227	94,389	203,781	8,890	194,891	141,615	34,736	15,102	3,438	1,057
32	Tot Non-Assoc Purch			442,789	154,830	286,902	12,638	274,264	201,285	48,887	19,550	4,541	1,057
33	Interchg Agr Capacity	P10WoN	557	55,724	19,119	36,460	1,603	34,857	25,531	6,213	2,528	585	145
34	Interchg Agr Energy	E8760	557	14,378	4,536	9,792	427	9,365	6,805	1,669	726	165	51
35	Tot Wis Interchg Purch			70,102	23,655	46,251	2,030	44,221	32,336	7,882	3,254	750	196
36	**Tot Purchased Power**			512,891	178,485	333,153	14,668	318,485	233,621	56,769	22,804	5,291	1,254
	Other Production		500,502,505-507 509-514,517-519,520,										
37	Capacity Related	D10S	523-525,528-532,535,	95,684	40,284	55,400	2,498	52,902	39,770	9,432	2,965	736	0
38	Energy Related	E8760	539,543-546,548-550	358,488	113,083	244,138	10,650	233,488	169,661	41,615	18,093	4,119	1,267
39	Total Other Produc	21.07%	552-554,556,557 575.1-575.8	454,171.415	153,366	299,539	13,149	286,390	209,431	51,047	21,058	4,854	1,267
40	**Total Production**			1,588,155	527,770	1,055,670	46,269	1,009,401	736,996	179,916	75,208	17,281	4,715
41	**Transmission Exp**	D10S	560-563, 565-568 570-573	266,511	112,203	154,308	6,958	147,350	110,773	26,270	8,258	2,049	0

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company

2023 Class Cost of Service Detail ($000)

Docket No. E002/GR-20-723
Exhibit___(MAP), Schedule 8

Operating & Maint (Pg 2 of 2)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Distribution Expen	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Supervision & Eng'rg	ZDTS	580,590	12,959	7,841	4,369	537	3,832	3,139	676	14	3	750
2	Load Dispatching	T20D80	581	1,611	687	916	48	869	709	166	(9)	2	8
3	Substations	P61	582,591,592	8,034	3,349	4,639	238	4,401	3,501	884	15	0	46
4	Overhead Lines	POL	583,593	47,571	30,243	14,856	1,829	13,026	10,664	2,363	0	0	2,473
5	Underground Lines	PUL	584, 594	19,227	14,202	4,943	818	4,125	3,383	742	0	0	82
6	Line Transformers	P68	595	1,480	1,043	431	73	358	338	19	0	0	5
7	Meters	C12WM	586,597,598	2,219	1,534	680	230	449	428	20	1	0	5
8	Customer Install'n	OXDTS	587	4,005	2,482	1,283	157	1,126	922	203	0	0	240
9	Street Lighting	Dir Assign	585,596	2,352	0	0	0	0	0	0	0	0	2,352
10	Miscellaneous	OXDTS	588	31,598	19,585	10,123	1,238	8,884	7,276	1,604	3	1	1,890
11	Rents (Pole Attachmts)	POL	589	4,600	2,924	1,436	177	1,259	1,031	228	0	0	239
12	**Total Distribution**			135,655	83,891	43,675	5,345	38,330	31,393	6,906	24	7	8,089
13	**Customer Accounting**	C11WA	901-905	41,826	35,155	6,538	3,329	3,209	3,147	59	2	1	132
14	**Sales, Econ Dvlp & Other**	R01	912	283	111	170	10	160	121	26	10	3	3
	Admin & General												
15	Salaries	LABOR	920	83,611	31,618	51,134	2,438	48,696	36,034	8,697	3,216	748	860
16	Office Supplies	OXTS	921	60,835	22,621	37,809	1,847	35,962	26,549	6,376	2,451	585	406
17	Admin Transfer Credit	OXTS	922	(51,697)	(19,223)	(32,129)	(1,569)	(30,560)	(22,561)	(5,418)	(2,083)	(497)	(345)
18	Outside Services	LABOR	923	14,993	5,670	9,169	437	8,732	6,462	1,560	577	134	154
19	Property Insurance	NEPIS	924	7,666	3,391	4,189	238	3,950	2,963	702	228	57	86
20	Pensions & Benefits	LABOR	926	67,820	25,646	41,476	1,977	39,499	29,229	7,055	2,609	607	697
21	Injuries & Claims	LABOR	925	12,903	4,879	7,891	376	7,515	5,561	1,342	496	115	133
22	Regulatory Exp	R01; R02	928	6,282	2,456	3,769	215	3,554	2,693	571	227	63	57
23	General Advertising	OXTS	930.1	116	43	72	4	69	51	12	5	1	1
24	Contributions	OXTS		0	0	0	0	0	0	0	0	0	0
25	Misc General Exp	OXTS	929, 930.2	(3)	(1)	(2)	(0)	(2)	(1)	(0)	(0)	(0)	(0)
26	Rents	OXTS	931	35,949	13,367	22,342	1,091	21,250	15,688	3,768	1,449	346	240
27	Maint of General Plant	OXTS	935	141	52	88	4	83	62	15	6	1	1
28	Total			238,616	90,519	145,807	7,059	138,749	102,728	24,679	9,180	2,161	2,290
	Cust Service & Info												
29	Cust Assist Exp - Non-CIP	C11P10	908	2,442	1,485	929	114	815	607	138	57	13	29
30	CIP Total	E99XCIP	908	125,604.412	40,605	84,414	3,828	80,586	61,548	13,418	4,010	1,610	586
31	Instructional Advertising	C11P10	909	569	346	216	26	190	141	32	13	3	7
32	Total			128,615	42,435	85,559	3,968	81,591	62,297	13,588	4,080	1,626	621
33	Amortizations	LABOR		49,467	18,706	30,252	1,442	28,810	21,319	5,146	1,903	443	509
34	**Total O&M Expense**			2,449,128	910,791	1,521,980	74,379	1,447,601	1,068,774	256,591	98,665	23,571	16,358

Northern States Power Company

2023 Class Cost of Service Detail ($000)

Book Depreciation

Line	Item	Alloc	FERC Accounts	1=2+3+10 MN	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5=6 to 9 Demand	6 Second	7 Primary	8 Tr Transf	9 Trans	10 St Ltg
	Production												
1	Peaking Plant	D10S		108,275	45,585	62,691	2,827	59,864	45,004	10,673	3,355	832	0
2	Base Load	E8760		334,893	105,640	228,070	9,949	218,121	158,495	38,876	16,902	3,847	1,183
3	Total		403,413	443,169	151,225	290,761	12,776	277,984	203,498	49,549	20,257	4,680	1,183
	Transmission												
4	Gen Step Up Base	E8760		1,901	600	1,294	56	1,238	900	221	96	22	7
5	Gen Step Up Peak	D10S		1,120	471	648	29	619	465	110	35	9	0
6	Total Gen Step Up			3,020	1,071	1,943	86	1,857	1,365	331	131	30	7
7	Bulk Transmission	D10S		74,528	31,377	43,151	1,946	41,205	30,977	7,346	2,309	573	0
8	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
9	Direct Assign	Dir Assign		180	0	180	0	180	20	0	0	160	0
10	Total		403,413	77,728	32,448	45,274	2,031	43,242	32,362	7,677	2,440	764	7
	Distribution												
11	Generat Step Up	STRATH		69	23	46	2	44	32	8	3	1	0
12	Bulk Transmission	D10S		44	18	25	1	24	18	4	1	0	0
13	Distrib Function	D60Sub		17,768	7,603	10,060	540	9,520	7,932	1,845	(258)	0	105
14	Direct Assign	Dir Assign		449	0	449	0	449	10	157	282	0	0
15	Total Substations		403,413	18,329	7,645	10,580	543	10,037	7,992	2,014	29	1	105
16	Overhead Lines	POL		42,107	26,769	13,149	1,619	11,530	9,439	2,091	0	0	2,189
17	Underground	PUL		44,785	33,081	11,514	1,905	9,609	7,880	1,729	0	0	190
18	Line Transformers	P68		10,943	7,716	3,187	541	2,645	2,502	143	0	0	41
19	Services	P69		10,139	9,099	1,040	295	745	745	0	0	0	0
20	Meters	C12WM		6,470	4,474	1,982	672	1,310	1,249	58	2	1	15
21	Street Lighting	P73		3,832	0	0	0	0	0	0	0	0	3,832
22	Total		403,413	136,605	88,783	41,451	5,575	35,876	29,807	6,036	31	2	6,371
23	**General & Common Plant**	PTD	403,413	135,327	57,094	77,033	4,184	72,849	54,296	12,928	4,522	1,103	1,200
24	**Total Book Deprec**		403,404	792,829	329,549	454,518	24,567	429,951	319,963	76,191	27,249	6,548	8,761

Real Estate & Property Tax

Line	Item	Alloc	FERC Accounts	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
	Production												
25	Peaking Plant	D10S		25,970	10,934	15,036	678	14,358	10,794	2,560	805	200	0
26	Base Load	E8760		73,137	23,071	49,808	2,173	47,635	34,614	8,490	3,691	840	258
27	Total		408.1	99,107	34,004	64,845	2,851	61,994	45,408	11,050	4,496	1,040	258
	Transmission												
28	Gen Step Up Base	E8760		1,278.0881	403	870	38	832	605	148	65	15	5
29	Gen Step Up Peak	D10S		483.0620	203	280	13	267	201	48	15	4	0
30	Total Gen Step Up			1,761.1501	607	1,150	51	1,100	806	196	79	18	5
31	Bulk Transmission	D10S		47,014.8280	19,794	27,221	1,227	25,994	19,541	4,634	1,457	361	0
32	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
33	Direct Assign	Dir Assign		112	0	112	0	112	12	0	0	100	0
34	Total		408.1	48,888.446	20,400	28,484	1,278	27,206	20,359	4,830	1,536	480	5
	Distribution												
35	Generat Step Up	STRATH		43	14	28	1	27	20	5	2	0	0
36	Bulk Transmission	D10S		27	11	16	1	15	11	3	1	0	0
37	Distrib Function	D60Sub		10,990	4,703	6,222	334	5,888	4,906	1,141	(159)	0	65
38	Direct Assign	Dir Assign		283	0	283	0	283	6	99	178	0	0
39	Total Substations			11,343	4,728	6,550	336	6,214	4,943	1,248	22	1	65
40	Overhead Lines	POL		17,248	10,965	5,386	663	4,723	3,866	857	0	0	897
41	Underground	PUL		24,942	18,424	6,412	1,061	5,351	4,389	963	0	0	106
42	Line Transformers	P68		5,585	3,938	1,626	276	1,350	1,277	73	0	0	21
43	Services	P69		4,061	3,645	416	118	298	298	0	0	0	0
44	Meters	C12WM		1,661	1,148	509	173	336	321	15	0	0	4
45	Street Lighting	P73		1,013	0	0	0	0	0	0	0	0	1,013
46	Total		408.1	65,852	42,848	20,900	2,627	18,273	15,094	3,155	22	1	2,105
47	**General & Common Plant**	PTD	408.1	0	0	0	0	0	0	0	0	0	0
48	**Tot Rl Est & Pr Tax**			213,848	97,253	114,228	6,756	107,472	80,862	19,036	6,054	1,521	2,368
49	Gross Earnings Tax	R01; R02		0	0	0	0	0	0	0	0	0	0
50	Payroll Taxes	LABOR		28,308	10,705	17,312	825	16,487	12,200	2,945	1,089	253	291
51	**Tot Non-Inc Taxes**			242,156	107,957	131,540	7,581	123,959	93,061	21,980	7,143	1,774	2,659

Northern States Power Company

2023 Class Cost of Service Detail ($000)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Provision For Defer Inc Tax												
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		(10,840)	(4,564)	(6,276)	(283)	(5,993)	(4,506)	(1,069)	(336)	(83)	0
2	Nuclear Fuel	E8760		908	287	619	27	592	430	105	46	10	3
3	Base Load	E8760		(13,595)	(4,289)	(9,259)	(404)	(8,855)	(6,434)	(1,578)	(686)	(156)	(48)
4	Total		410, 411	(23,527)	(8,566)	(14,916)	(660)	(14,256)	(10,510)	(2,541)	(976)	(229)	(45)
	Transmission												
5	Gen Step Up Base	E8760		538	170	366	16	350	254	62	27	6	2
6	Gen Step Up Peak	D10S		183	77	106	5	101	76	18	6	1	0
7	Total Gen Step Up			721	247	472	21	451	331	80	33	8	2
8	Bulk Transmission	D10S		6,337	2,668	3,669	165	3,503	2,634	625	196	49	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		13	0	13	0	13	1	0	0	11	0
11	Total		410, 411	7,070	2,914	4,154	186	3,967	2,966	705	229	68	2
	Distribution												
12	Generat Step Up	STRATH		(28)	(9)	(18)	(1)	(17)	(13)	(3)	(1)	(0)	(0)
13	Bulk Transmission	D10S		(6)	(3)	(4)	(0)	(4)	(3)	(1)	(0)	(0)	0
14	Distrib Function	D60Sub		733	313	415	22	393	327	76	(11)	0	4
15	Direct Assign	Dir Assign		(50)	0	(50)	0	(50)	(1)	(17)	(31)	(0)	0
16	Total Substations			649	302	343	21	322	311	55	(43)	(0)	4
17	Overhead Lines	POL		4,994	3,175	1,559	192	1,367	1,119	248	0	0	260
18	Underground	PUL		(614)	(453)	(158)	(26)	(132)	(108)	(24)	0	0	(3)
19	Line Transformers	P68		(2,538)	(1,789)	(739)	(125)	(613)	(580)	(33)	0	0	(9)
20	Services	P69		(1,767)	(1,586)	(181)	(51)	(130)	(130)	0	0	0	0
21	Meters	C12WM		794	549	243	83	161	153	7	0	0	2
22	Street Lighting	P73		(650)	0	0	0	0	0	0	0	0	(650)
23	Total		410, 411	868	197	1,068	93	975	765	253	(43)	(0)	(397)
24	**General & Common Plant**	PTD	410, 411	1,897	801	1,080	59	1,021	761	181	63	15	17
25	**Net Operating Loss (NOL) Carry**	NEPIS		(135,490)	(59,933)	(74,032)	(4,215)	(69,818)	(52,362)	(12,414)	(4,031)	(1,011)	(1,524)
26	**Non - Plant Related**	LABOR	410, 411	3,285	1,242	2,009	96	1,913	1,416	342	126	29	34
27	**Tot Prov For Defer**			(145,897)	(63,345)	(80,638)	(4,441)	(76,197)	(56,964)	(13,474)	(4,631)	(1,128)	(1,913)
	Inv Tax Credit; Total Oper Exp												
	Production												
28	Peaking Plant	D10S		(260)	(109)	(150)	(7)	(144)	(108)	(26)	(8)	(2)	0
29	Base Load	E8760		(538)	(170)	(367)	(16)	(351)	(255)	(63)	(27)	(6)	(2)
30	Total		411	(798)	(279)	(517)	(23)	(494)	(363)	(88)	(35)	(8)	(2)
	Transmission												
31	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
32	Gen Step Up Peak	D10S		0	0	0	0	0	0	0	0	0	0
33	Total Gen Step Up			0	0	0	0	0	0	0	0	0	0
34	Bulk Transmission	D10S		(150)	(63)	(87)	(4)	(83)	(62)	(15)	(5)	(1)	0
35	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
36	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
37	Total		411	(150)	(63)	(87)	(4)	(83)	(62)	(15)	(5)	(1)	0
	Distribution												
38	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
39	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
40	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
41	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
42	Total Substations			0	0	0	0	0	0	0	0	0	0
43	Overhead Lines	POL		(264)	(168)	(82)	(10)	(72)	(59)	(13)	0	0	(14)
44	Underground	PUL		0	0	0	0	0	0	0	0	0	0
45	Line Transformers	P68		0	0	0	0	0	0	0	0	0	0
46	Services	P69		0	0	0	0	0	0	0	0	0	0
47	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
48	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
49	Total		411	(264)	(168)	(82)	(10)	(72)	(59)	(13)	0	0	(14)
50	**General & Common Plant**	PTD	411	(7)	(3)	(4)	(0)	(4)	(3)	(1)	(0)	(0)	(0)
51	**Net Inv Tax Credit**			(1,218)	(513)	(690)	(37)	(653)	(487)	(117)	(40)	(9)	(16)
28	TBT Misc Net Exp	NEPIS		0	0	0	0	0	0	0	0	0	0
52	**Total Operating Exp**			**3,336,998**	**1,284,439**	**2,026,710**	**102,049**	**1,924,661**	**1,424,347**	**341,173**	**128,386**	**30,756**	**25,849**
53A	**Pres Op Inc Before Inc Tax**			**262,831**	**108,182**	**151,640**	**18,103**	**133,537**	**127,686**	**(4,512)**	**5,090**	**5,273**	**3,008**
53B	**Prop Op Inc Before Inc Tax**			**860,187**	**361,690**	**489,170**	**33,048**	**456,122**	**370,586**	**50,041**	**24,807**	**10,689**	**9,327**

2023 Class Cost of Service Detail ($000)

Tax Deprec; Inc Tax & Return

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		93,204	39,240	53,964	2,433	51,531	38,739	9,187	2,888	717	0
2	Nuclear Fuel	E8760		100,364	31,659	68,350	2,982	65,368	47,499	11,651	5,065	1,153	355
3	Base Load	E8760		378,620	119,433	257,849	11,249	246,600	179,189	43,952	19,109	4,350	1,338
4	Total		tax books	572,188	190,332	380,163	16,664	363,500	265,428	64,791	27,062	6,219	1,693
	Transmission												
5	Gen Step Up Base	E8760		3,992	1,259	2,719	119	2,600	1,889	463	201	46	14
6	Gen Step Up Peak	D10S		1,441	607	835	38	797	599	142	45	11	0
7	Total Gen Step Up			5,434	1,866	3,553	156	3,397	2,489	606	246	57	14
8	Bulk Transmission	D10S		107,841	45,402	62,439	2,815	59,624	44,823	10,630	3,341	829	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		245	0	245	0	245	27	0	0	218	0
11	Total		tax books	113,520	47,268	66,238	2,972	63,266	47,339	11,236	3,588	1,104	14
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		18	8	11	0	10	8	2	1	0	0
14	Distrib Function	D60Sub		22,422	9,595	12,695	681	12,014	10,010	2,329	(325)	0	132
15	Direct Assign	Dir Assign		250	0	250	0	250	5	88	157	0	0
16	Total Substations			22,691	9,603	12,956	682	12,274	10,023	2,418	(167)	0	132
17	Overhead Lines	POL		61,524	39,113	19,213	2,366	16,847	13,791	3,056	0	0	3,198
18	Underground	PUL		47,577	35,143	12,232	2,024	10,208	8,371	1,836	0	0	202
19	Line Transformers	P68		8,155	5,750	2,375	403	1,971	1,865	107	0	0	30
20	Services	P69		4,323	3,880	443	126	318	318	0	0	0	0
21	Meters	C12WM		9,338	6,456	2,860	970	1,890	1,802	84	2	1	21
22	Street Lighting	P73		2,154	0	0	0	0	0	0	0	0	2,154
23	Total		tax books	155,761	99,945	50,079	6,570	43,508	36,171	7,501	(165)	1	5,738
24	**General & Common Plant**	PTD	tax books	163,797	69,106	93,239	5,064	88,175	65,719	15,648	5,473	1,335	1,453
25	Net Operating Loss (NOL) Carry F	NEPIS		0	0	0	0	0	0	0	0	0	0
26	**Total Tax Deprec**			1,005,266	406,650	589,719	31,270	558,449	414,656	99,176	35,958	8,659	8,897
27	Interest Expense		427,431	209,927.83	92,623	114,982	6,525	108,457	81,307	19,297	6,288	1,565	2,323
28	Other Tax Timing Differ	LABOR		1,385	524	847	40	807	597	144	53	12	14
29	Meals & Enter	LABOR		1,112	420	680	32	647	479	116	43	10	11
30	Total Tax Deductions			1,217,691	500,217	706,228	37,867	668,361	497,039	118,733	42,343	10,247	11,246
	Inc Tax Additions												
31	Book Depreciation			792,829	329,549	454,518	24,567	429,951	319,963	76,191	27,249	6,548	8,761
32	Deferred Inc Tax & ITC			(147,115.15)	(63,858)	(81,328)	(4,478)	(76,850)	(57,451)	(13,590)	(4,672)	(1,137)	(1,929)
33	Nuclear Fuel Book Burn	E8760		100,409	31,673	68,381	2,983	65,398	47,521	11,656	5,068	1,154	355
34	Tax Capitalized Leases	PTD		41,642	17,569	23,704	1,287	22,417	16,708	3,978	1,391	339	369
35	Avoided Tax Interest	RTBASE		16,509	7,284	9,043	513	8,529	6,394	1,518	495	123	183
36	Total Tax Additions			804,275	322,218	474,318	24,872	449,445	333,134	79,753	29,531	7,027	7,739
37	**Total Inc Tax Adjustments**			(413,416)	(177,999)	(231,910)	(12,995)	(218,915)	(163,905)	(38,980)	(12,811)	(3,220)	(3,506)
38A	**Pres Taxable Net Income**			(150,586)	(69,817)	(80,270)	5,108	(85,378)	(36,218)	(43,492)	(7,721)	2,053	(498)
38B	**Prop Taxable Net Income**			446,770	183,690	257,260	20,053	237,207	206,681	11,061	11,996	7,469	5,820
39A	Pres Fed & State Inc Tax			(61,484)	(28,098)	(33,041)	902	(33,943)	(17,460)	(14,174)	(2,765)	454	(345)
38A	Exp Fed & State Inc Tax			110,208	39,275	69,732	6,787	62,946	55,957	1,390	3,424	2,174	1,201
39B	Prop Fed & State Inc Tax			110,208	44,765	63,972	5,198	58,774	52,354	1,506	2,902	2,011	1,471
40A	Pres Preliminary Return	(total); BASE		324,314	136,280	184,681	17,201	167,481	145,146	9,662	7,854	4,818	3,353
40B	Prop Preliminary Return	(total); BASE		749,978	316,925	425,198	27,850	397,348	318,232	48,535	21,904	8,678	7,855
41	Total AFUDC			31,124	12,597	18,406	923	17,483	13,061	3,119	1,049	254	120
42A	**Present Total Return**			355,438	148,877	203,087	18,124	184,963	158,207	12,780	8,903	5,072	3,473
42B	**Proposed Total Return**			781,102	329,522	443,604	28,773	414,831	331,293	51,654	22,953	8,932	7,976
43A	**Pres % Return on Rate Base**			3.34%	3.17%	3.48%	5.47%	3.36%	3.83%	1.30%	2.79%	6.39%	2.95%
43B	**Prop % Return on Rate Base**			7.33%	7.01%	7.60%	8.69%	7.53%	8.03%	5.27%	7.19%	11.25%	6.76%
44A	**Present Common Return**			145,510	56,255	88,105	11,599	76,506	76,900	(6,517)	2,615	3,508	1,151
44B	**Proposed Common Return**			571,174	236,899	328,622	22,248	306,374	249,986	32,357	16,665	7,367	5,653
45A	**Pres % Ret on Common Rt Base**			2.60%	2.28%	2.88%	6.67%	2.65%	3.55%	-1.27%	1.56%	8.41%	1.86%
45B	**Prop % Ret on Common Rt Base**			10.21%	9.60%	10.72%	12.79%	10.60%	11.54%	6.29%	9.94%	17.67%	9.13%

2023 Class Cost of Service Detail ($000)

	Allow For Funds Used During Constr			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		4,172	1,756	2,416	109	2,307	1,734	411	129	32	0
2	Nuclear Fuel	E8760		5,189	1,637	3,534	154	3,380	2,456	602	262	60	18
3	Base Load	E8760		4,778	1,507	3,254	142	3,112	2,261	555	241	55	17
4	Total		419.1,432	14,140	4,901	9,204	405	8,799	6,451	1,568	632	147	35
	Transmission												
5	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10S		0	0	0	0	0	0	0	0	0	0
7	Total Gen Step Up			0	0	0	0	0	0	0	0	0	0
8	Bulk Transmission	D10S		9,205	3,876	5,330	240	5,089	3,826	907	285	71	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
11	Total		419.1,432	9,205	3,876	5,330	240	5,089	3,826	907	285	71	0
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		1,347	576	763	41	722	601	140	(20)	0	8
15	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
16	Total Substations			1,347	576	763	41	722	601	140	(20)	0	8
17	Overhead Lines	POL		622	395	194	24	170	139	31	0	0	32
18	Underground	PUL		1,007	744	259	43	216	177	39	0	0	4
19	Line Transformers	P68		0	0	0	0	0	0	0	0	0	0
20	Services	P69		0	0	0	0	0	0	0	0	0	0
21	Meters	C12WM		294	203	90	30	59	57	3	0	0	1
22	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
23	Total		419.1,432	3,270	1,919	1,306	138	1,168	975	212	(19)	0	45
24	**General & Common Plant**	PTD	419.1,432	4,509	1,902	2,566	139	2,427	1,809	431	151	37	40
25	**Total AFUDC**			31,124	12,597	18,406	923	17,483	13,061	3,119	1,049	254	120
	Labor Allocator												
	Production												
26	Other Prod - Cap	D10S		75,066	31,603	43,463	1,960	41,503	31,200	7,399	2,326	577	0
27	Other Prod - Ene	E8760		211,401	66,685	143,969	6,281	137,688	100,050	24,541	10,669	2,429	747
28	Total		500 through 557	286,467	98,288	187,431	8,240	179,191	131,250	31,940	12,995	3,006	747
	Transmission												
29	Stepup Subtrans	P5161A		1,494	514	976	43	933	684	166	67	16	4
30	Bulk Power Subs	D10S		39,887	16,793	23,094	1,041	22,053	16,579	3,932	1,236	307	0
31	Total		560 through 571	41,381	17,307	24,070	1,084	22,986	17,262	4,098	1,303	322	4
	Distribution												
32	Superv & Eng	ZDTS	580, 590	11,648	7,047	3,927	483	3,444	2,822	608	12	2	674
33	Load Dispatch	D10S	581	918	387	532	24	508	382	91	28	7	0
34	Substation	P61	582, 592	5,481	2,285	3,165	162	3,002	2,389	603	10	0	31
35	Overhead Lines	POL	583, 593	9,492	6,034	2,964	365	2,599	2,128	471	0	0	493
36	Underground Lines	PUL	584, 594	8,057	5,952	2,071	343	1,729	1,418	311	0	0	34
37	Line Transformer	P68	595	1,264	891	368	63	306	289	17	0	0	5
38	Meter	C12WM	586, 597	2,472	1,709	757	257	500	477	22	1	0	6
39	Cust Installation	ZDTS	587	3,670	2,220	1,237	152	1,085	889	192	4	1	212
40	Street Lighting	P73	585, 596	1,076	0	0	0	0	0	0	0	0	1,076
41	Miscellaneous	OXDTS	588	9,636	5,973	3,087	378	2,709	2,219	489	1	0	576
42	Total			53,714	32,498	18,108	2,226	15,883	13,011	2,804	56	11	3,108
43	**Cust Accounting**	C11WA	901,902,903,904,905	(8,927)	(7,503)	(1,395)	(710)	(685)	(672)	(13)	(0)	(0)	(28)
44	**Sales Expense**	C11P10	912	9	5	3	0	3	2	0	0	0	0
45	**Admin & General**	LABOR	920,921,922,923,924,	153,329	57,982	93,771	4,470	89,301	66,081	15,950	5,898	1,372	1,577
46	**Service & Inform**	C11P10	908, 909	1,393	847	529	65	465	346	79	32	7	16
47	**Labor**			527,366	199,424	322,518	15,375	307,143	227,282	54,858	20,285	4,718	5,424

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NOT PUBLIC DATA HAS BEEN EXCISED

2023 Class Cost of Service Detail ($000)

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	
INTERNAL ALLOCATORS		Intern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	50% Cus, 50% Prod Plt	C11P10	100.00%	60.80%	38.02%	4.65%	33.37%	24.87%	5.64%	2.32%	0.54%	1.17%
2	Peaking Plant Capacity	D10S	100.00%	42.10%	57.90%	2.61%	55.29%	41.56%	9.86%	3.10%	0.77%	0.00%
3	57% Dmd; 43% Energy: Sales & E	D57E43	100.00%	31.54%	68.10%	2.97%	65.13%	47.33%	11.61%	5.05%	1.15%	0.35%
4	40% Dmd; 60% Energy: CIP	D40E60	100.00%	31.54%	68.10%	2.97%	65.13%	47.33%	11.61%	5.05%	1.15%	0.35%
5	20%D10T; 80%D60Sub	T20D80	100.00%	42.65%	56.87%	2.95%	53.92%	44.03%	10.28%	-0.54%	0.15%	0.47%
6	Labor w/o (or w/) A&G	LABOR	100.00%	37.82%	61.16%	2.92%	58.24%	43.10%	10.40%	3.85%	0.89%	1.03%
7	Net Plant In Service	NEPIS	100.00%	44.23%	54.64%	3.11%	51.53%	38.65%	9.16%	2.98%	0.75%	1.13%
8	Dis O&M w/o Sup & Misc	OXDTS	100.00%	61.98%	32.04%	3.92%	28.12%	23.03%	5.08%	0.01%	0.00%	5.98%
9	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	100.00%	37.18%	62.15%	3.04%	59.11%	43.64%	10.48%	4.03%	0.96%	0.67%
10	Production Plant	P10	100.00%	33.70%	66.02%	2.90%	63.12%	46.15%	11.25%	4.65%	1.07%	0.28%
11	Production Plant Wo Nuclear	P10WoN	100.00%	34.31%	65.43%	2.88%	62.55%	45.82%	11.15%	4.54%	1.05%	0.26%
12	Total P51 & P61A	P5161A	100.00%	34.42%	65.33%	2.87%	62.45%	45.76%	11.13%	4.52%	1.05%	0.26%
13	Distribution Plant	P60	100.00%	65.07%	31.74%	3.99%	27.75%	22.92%	4.79%	0.03%	0.00%	3.20%
14	Distr Substn Plant	P61	100.00%	41.69%	57.74%	2.96%	54.78%	43.58%	11.00%	0.19%	0.01%	0.57%
15	Line Transformer Plant	P68	100.00%	70.51%	29.12%	4.95%	24.17%	22.87%	1.31%	0.00%	0.00%	0.37%
16	Services Plant	P69	100.00%	89.75%	10.25%	2.91%	7.35%	7.35%	0.00%	0.00%	0.00%	0.00%
17	Dist Plt Overhead Lines	POL	100.00%	63.57%	31.23%	3.84%	27.38%	22.42%	4.97%	0.00%	0.00%	5.20%
18	Real Est & Property Tax	PT0	100.00%	45.48%	53.42%	3.16%	50.26%	37.81%	8.90%	2.83%	0.71%	1.11%
19	Produc, Trans & Distrib	PTD	100.00%	42.19%	56.92%	3.09%	53.83%	40.12%	9.55%	3.34%	0.81%	0.89%
20	Dist Plt Undground Lines	PUL	100.00%	73.87%	25.71%	4.25%	21.46%	17.60%	3.86%	0.00%	0.00%	0.42%
21	Rate Base (Non-Column)	RTBASE	100.00%	44.12%	54.77%	3.11%	51.66%	38.73%	9.19%	3.00%	0.75%	1.11%
22	Stratified Hydro Baseload	STRATH	100.00%	33.33%	66.37%	2.91%	63.46%	46.35%	11.31%	4.72%	1.08%	0.29%
23	Transmission & Distrib	TD	100.00%	54.69%	43.53%	3.38%	40.16%	31.25%	7.05%	1.42%	0.44%	1.78%
24	Labor Dis w/o Sup & Eng	ZDTS	100.00%	60.50%	33.71%	4.14%	29.57%	24.22%	5.22%	0.11%	0.02%	5.79%

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
INTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
25	Labor w/o A&G	LABOR(S)	374,037	141,442	228,748	10,905	217,843	161,201	38,908	14,387	3,347	3,847
26	Dis O&M w/o Sup, Cust Install & M	OXDTS	87,093	53,983	27,901	3,413	24,488	20,055	4,422	7	3	5,210
27	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	2,397,505	891,475	1,490,031	72,787	1,417,244	1,046,294	251,268	96,611	23,071	15,999
28	Total P51 & P61A	P5161A	137,917	47,465	90,097	3,962	86,135	63,110	15,353	6,230	1,442	355
29	Produc, Trans & Distrib	PTD	20,809,191	8,779,341	11,845,290	643,339	11,201,951	8,349,093	1,988,008	695,293	169,556	184,560
30	Transmission & Distrib	TD	8,417,698	4,603,342	3,664,641	284,311	3,380,329	2,630,442	593,859	119,213	36,815	149,715
31	Labor Dis w/o Sup & Eng, Cust In	ZDTS	38,397	23,231	12,944	1,591	11,353	9,301	2,004	40	8	2,221

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NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company

2023 Class Cost of Service Detail ($000)

Docket No. E002/GR-20-723
Exhibit___(MAP), Schedule 8

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
EXTERNAL ALLOCATORS		Extern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Customers - Ave Monthly	C11	100.00%	87.91%	10.02%	6.40%	3.62%	3.58%	0.03%	0.00%	0.00%	2.07%
2	Cust Acctg Wtg Factor	C11WA	100.00%	84.05%	15.63%	7.96%	7.67%	7.52%	0.14%	0.01%	0.00%	0.32%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	69.14%	30.63%	10.39%	20.24%	19.30%	0.90%	0.03%	0.01%	0.23%
4	Sec & Pri Customers	C61PS	100.00%	89.36%	10.20%	6.51%	3.69%	3.65%	0.04%	0.00%	0.00%	0.44%
5	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	100.00%	95.11%	4.50%	3.84%	0.66%	0.65%	0.01%	0.00%	0.00%	0.39%
6	C62Sec, w/o Ltg & C/I Undergrou	C62NL	100.00%	95.00%	5.00%	3.20%	1.80%	1.80%	0.00%	0.00%	0.00%	0.00%
7	Secondary Customers	C62Sec	100.00%	89.39%	10.17%	6.52%	3.66%	3.66%	0.00%	0.00%	0.00%	0.44%
8	Summer Peak Resp KW	D10S	100.00%	42.10%	57.90%	2.61%	55.29%	41.56%	9.86%	3.10%	0.77%	0.00%
9	Transmission Demand %	D10T	100.00%	39.50%	60.18%	2.84%	57.33%	42.66%	10.09%	3.62%	0.96%	0.33%
10	Winter Peak Resp KW	D10W	100.00%	35.79%	63.42%	3.18%	60.25%	44.23%	10.43%	4.36%	1.23%	0.79%
11	Alternative Production Allocator	1CP	100.00%	42.10%	57.90%	2.61%	55.29%	41.56%	9.86%	3.10%	0.77%	0.00%
12	Sec, Pri & TT, Class Coin kW @ $	D60Sub	100.00%	42.79%	56.62%	3.04%	53.58%	44.64%	10.39%	-1.45%	0.00%	0.59%
13	Sec & Pri, Cl Coin kW (no Min Sy	D61PS	100.00%	36.61%	63.05%	2.45%	60.60%	48.53%	12.07%	0.00%	0.00%	0.34%
14	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	100.00%	74.86%	24.55%	2.77%	21.78%	16.63%	5.14%	0.00%	0.00%	0.59%
15	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	100.00%	73.22%	26.78%	1.98%	24.80%	24.80%	0.00%	0.00%	0.00%	0.00%
16	Sec, Class Coin kW (w/o Min Sys	D62SecL	100.00%	48.70%	51.03%	3.02%	48.01%	48.01%	0.00%	0.00%	0.00%	0.27%
17	Direct Assign Street Lighting	DASL	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
18	On + Off Sales MWH	E8760	100.00%	31.54%	68.10%	2.97%	65.13%	47.33%	11.61%	5.05%	1.15%	0.35%
19	Street Lighting (Dir Assign)	P73	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
20	MWh Sales Excl CIP Exempt	E99XCIP	100.00%	32.33%	67.21%	3.05%	64.159%	49.00%	10.68%	3.19%	1.28%	0.47%
21	Present Rev	R01	100.00%	39.10%	60.00%	3.43%	56.57%	42.86%	9.09%	3.61%	1.00%	0.90%
22	Late Fee Revenue Allocator	LateFee	100.00%	84.95%	14.99%	3.01%	11.98%	10.95%	1.02%	0.01%	0.00%	0.06%

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
EXTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
23	Customers - B Basis	C10	1,333,626	1,191,720	136,095	86,872	49,223	48,728	473	13	9	5,811
24	Cust - Ave Monthly (C10-Area Lt)	C11	1,359,826	1,195,411	136,291	87,068	49,223	48,728	473	13	9	28,124
25	Mo Cus Wtd By Cus Acct	C11WA	1,422,221	1,195,411	222,316	113,189	109,128	107,000	2,005	75	47	4,494
26	Cust Acctg Wtg Factor	C11WAF	19.72	1.00	18.72	1.30	17.42	2.20	4.24	5.75	5.24	N/A
27	Cust-Ave Mo (C11 w/ Dir Assign $	C12	1,334,415	1,195,411	136,291	87,068	49,223	48,728	473	13	9	2,713
28	Mo Cus Wtd By Mtr Invest	C12WM	169,705,920	117,341,310	51,981,814	17,630,125	34,351,689	32,753,766	1,532,010	44,906	21,007	382,796
29	Meter Invest / Cust Factor	C12WMF	10,138	98	9,899	202	9,697	672	3,236	3,454	2,334	141
30	Sec & Pri Customers	C61PS	1,333,604	1,191,720	136,073	86,872	49,201	48,728	473	0	0	5,811
31	% Served by Primary Single Phase		0.0%	73.13%	0.00%	40.49%	0.00%	12.26%	15.23%	18.18%	22.22%	61.24%
32	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	916,286	871,510	41,217	35,172	6,045	5,973	72	0	0	3,558
33	C62Sec, w/o Ltg & C/I Undergrou	C62NL	1,254,458	1,191,720	62,738	40,193	22,545	22,545	0	0	0	0
34	Secondary Customers	C62Sec	1,333,130	1,191,720	135,600	86,872	48,728	48,728	0	0	0	5,811
35	Summer Peak Resp KW	D10S	35,569	14,975	20,594	929	19,665	14,784	3,506	1,102	273	0
36	Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	3,949,725	6,017,689	284,470	5,733,219	4,266,140	1,009,491	361,715	95,873	32,586
37	Winter Peak Resp KW	D10W	4,104	1,469	2,603	130	2,472	1,815	428	179	50	32
38	Alternative Production Allocator	1CP	35,569	14,975	20,594	929	19,665	14,784	3,506	1,102	273	0
39	Sec, Pri & TT, Class Coin kW @ $	D60Sub	6,047,261	2,587,740	3,423,891	183,740	3,240,151	2,699,777	628,017	(87,643)	0	35,630
40	Sec & Pri, Class Coin kW (w/o Mi	D61PS	5,496,409	2,012,097	3,465,457	134,496	3,330,961	2,667,313	663,648	0	0	18,854
41	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	1,965,486	1,471,456	482,484	54,454	428,029	326,944	101,085	0	0	11,546
42	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	10,222,704	7,485,119	2,737,585	202,679	2,534,906	2,534,906	0	0	0	0
43	Sec, Class Coin kW (w/o Min Sys	D62SecL	10,000,000	4,870,327	5,103,142	302,353	4,800,789	4,800,789	0	0	0	26,531
44	Annual Billing kW	D99	47,111.052	0	47,111	0	47,111	36,288	7,179	2,700	945	0
45	Summer Billing kW	D99S	17,357.236	0	17,357	0	17,357	13,350	2,694	935	378	0
46	Winter Billing kW	D99W	29,753.816	0	29,754	0	29,754	22,937	4,485	1,764	567	0
47	Non-Coinc Pk Second	DN-Sec	13,420,925	7,485,119	5,916,952	438,066	5,478,885	5,478,885	0	0	0	18,854
48	MWh Sales	E99	27,358,000	8,458,905	18,777,113	797,613	17,979,500	12,890,479	3,259,279	1,494,404	335,338	121,981
49	MWh Sales Excl CIP Exempt	E99XCIP	26,166,420	8,458,905	17,585,534	797,465	16,788,068	12,821,972	2,795,334	835,424	335,338	121,981
50	Late Fee Revenue Allocation	LateFee	100.00%	84.95%	14.99%	3.01%	11.98%	10.95%	1.02%	0.01%	0.00%	0.06%

CCOSS Model: Index of Spreadsheet Tabs

Tab No.	CCOSS Spreadsheet Tab Label	Spreadsheet Tab Description
1	CCOSS Worksheet Tab Index	Describes the data and analysis within each CCOSS worksheet tab.
2	CCOSS Summary	Shows a summary of CCOSS results; specifically Unadjusted Revenue Requirement, Adjusted Revenue Requirements and Revenue Deficiency are shown by Customer Class.
3	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.
4	RR-TOT	Shows detailed revenue requirement calculations for all functions and cost classifications combined.
5	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.
6	RR-DMD	Shows detailed revenue requirement calculations for costs that have been classified as Demand-Related.
7	RR-ENE	Shows detailed revenue requirement calculations for costs that have been classified as Energy-Related. RR-ENE = RR-On + RR-Off.
8	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.
9	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.
10	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.
11	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.
12	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.
13	RR-On	Shows detailed revenue requirement calculations for costs of fuel and purchases of energy for on-peak hours.
14	RR-Off	Shows detailed revenue requirement calculations for costs of fuel and purchases of energy for off-peak hours.
15	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.
16	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.
17	RR-Psub	Shows detailed revenue requirement calculations for Distribution substations.
18	RR-Prim	Shows detailed revenue requirement calculations for the capacity-related portion of primary voltage conductors, transformers and related facilities.
19	RR-Sec	Shows detailed revenue requirement calculations for the capacity-related portion of secondary voltage conductors, transformers and related facilities.
20	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.
21	RR_En_Svc	Shows detailed revenue requirement calculations for costs of meter reading, billing, customer service and costs of back office support.
22	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.
23	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.
24	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.

CCOSS Model: Index of Spreadsheet Tabs

Tab No.	CCOSS Spreadsheet Tab Label	Spreadsheet Tab Description
25	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.
26	JCOSS-Labels	Shows JCOSS line-item labels used in the Revenue Analysis RIS System.
27	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.
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 2020 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 Peaks	Has the TY2021 forecasted hourly loads for the NSP System. Also calculates the NSP System Load Factor.
35	InputData-NSP Syst Peaks Sorted	Has the TY2021 forecasted hourly loads for the NSP System sorted by load level. This tab is used to identify hours that should be used for the D10S allocator.
37	InputData-8760 Loads	Has TY2021 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.
38	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.
39	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.
40	InputData-Cust Fcst	Has the results of the 2021 customer forecast by customer class. These results were used in calculation allocation factors for customer-related costs.
41	InputData-MWh Sales Fcst	Has the results of the 2021 kWh sales forecast by customer class.
42	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.
43	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.
44	InputData-OthProdOM	Has the split of Other Production O&M costs into energy-related and capacity-related components using the "Location" method.
45	InputData-PlantStrat2019	Has the plant stratification analysis results. These peaking versus baseload results were applied as shown on the "JCOSS-Plant Stratified" and "InputData-OthProdOM" tabs.
46	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.
47	InputData-Dist1Ph3Ph	Shows the percent of customers that are served off 3 phase primary distribution lines versus 1 phase distribution lines.
48	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.
49	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.
50	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.
51	InputData-CustAcctgWt	Relative weighting by customer class for costs of meter reading, billing and collections and uncollectible accounts.

CCOSS Model: Index of Spreadsheet Tabs

Tab No.	CCOSS Spreadsheet Tab Label	Spreadsheet Tab Description
52	InputData-Write Off Analysis	Based of Accounting records for 2019 calculates the percent customer bill write offs by customer class for 2019. These ratios were used to determine customer class weights fo FERC code 904.
53	InputData-LateFees	Based on budgeted late fees for C&I versus Residential customers and a query of 2019 late fee revenues by customer class, provides an allocation factor for late fee revenues.
54	InputData-T&D Direct Assign $	Based on the customers served by direct assignment distribution substations and transmission radials, provides allocation factors for allocating these costs. **THIS TAB IS TRADE SECRET**
55	InputData-T&D Direct Assign MW	Has the MW loads of customers that have Distribution Substation costs directly assigned to them. These MW loads are excluded from the loads that are used to calculate the D60Sub Allocator. **THIS TAB IS TRADE SECRET**
56	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.
57	InputData-2021 Pres Prop Revenue	Has present 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 on page 149-150 of Kelly 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 on pages 151-154 of 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

	% of Costs Classified as Customer-Related	
Property Unit	**Zero Intercept Method**	**Minimum System Method**
Overhead Primary	34.9%	51.4%
Overhead Secondary	78.3%	89.6%
Overhead Transformers	72.7%	79.5%
Underground Primary	58.1%	53.2%
Underground Secondary	73.8%	100%
Underground Transformers	87.3%	51.5%

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)	34.9%	65.1%
Overhead Secondary (used Zero Intercept result)	78.3%	21.7%
Underground Primary (used Minimum System result)	53.2%	46.8%
Underground Secondary (used Zero Intercept result)	73.8%	26.2%
Weighted Average for Overhead and Underground Transformers (used Zero Intercept for OH Transformers; used Minimum System for UG Transformers)	64.1%	35.9%

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 wasn't 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	15,663,066	52.91%	52.91%	30.09%	30.09%
	2 AL 1ph	13,190,012	44.56%	97.47%	25.34%	55.43%
	1/0 Unknown 1ph	250,307	0.85%	98.31%	0.48%	55.92%
	1 AL 1ph	238,717	0.81%	99.12%	0.46%	56.37%
	Unknown AL 1ph	78,819	0.27%	99.38%	0.15%	56.53%
	Unknown Unknown 1ph	50,350	0.17%	99.55%	0.10%	56.62%
	0 0 1ph	43,038	0.15%	99.70%	0.08%	56.70%
	2 Unknown 1ph	34,982	0.12%	99.82%	0.07%	56.77%
	1/0 CU 1ph	16,400	0.06%	99.87%	0.03%	56.80%
	2/0 AL 1ph	9,574	0.03%	99.91%	0.02%	56.82%
	2 CU 1ph	8,547	0.03%	99.93%	0.02%	56.84%
	Unknown CU 1ph	4,504	0.02%	99.95%	0.01%	56.85%
	4/0 AL 1ph	4,020	0.01%	99.96%	0.01%	56.85%
	Footage of 16 Remaining 1 Phase Underground Primary Conductor Configurations	11,050	0.04%	100.00%	0.02%	56.88%
	Total 1 Phase	**29,603,387**	**100.00%**		**56.88%**	

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	12,837,974	57.20%	57.20%	24.67%	81.54%
	750 AL 3ph	4,426,067	19.72%	76.92%	8.50%	90.04%
	2 AL 3ph	1,161,402	5.17%	82.09%	2.23%	92.28%
	600 CU 3ph	862,737	3.84%	85.93%	1.66%	93.93%
	500 CU 3ph	543,913	2.42%	88.36%	1.05%	94.98%
	1000 AL 3ph	542,869	2.42%	90.78%	1.04%	96.02%
	500 AL 3ph	474,292	2.11%	92.89%	0.91%	96.93%
	1/0 Unknown 3ph	353,252	1.57%	94.46%	0.68%	97.61%
	750 CU 3ph	291,013	1.30%	95.76%	0.56%	98.17%
	Unknown Unknown 3ph	167,672	0.75%	96.51%	0.32%	98.49%
	500 Unknown 3ph	137,705	0.61%	97.12%	0.26%	98.76%
	1 AL 3ph	119,022	0.53%	97.65%	0.23%	98.99%
	350 CU 3ph	99,870	0.44%	98.09%	0.19%	99.18%
	4/0 CU 3ph	96,745	0.43%	98.53%	0.19%	99.36%
	1/0 CU 3ph	87,647	0.39%	98.92%	0.17%	99.53%
	0 0 3ph	54,888	0.24%	99.16%	0.11%	99.64%
	400 CU 3ph	46,278	0.21%	99.37%	0.09%	99.73%
	750 Unknown 3ph	27,563	0.12%	99.49%	0.05%	99.78%
	Unknown AL 3ph	23,418	0.10%	99.59%	0.04%	99.82%
	2 Unknown 3ph	23,162	0.10%	99.70%	0.04%	99.87%
	4/0 Unknown 3ph	20,396	0.09%	99.79%	0.04%	99.91%
	600 Unknown 3ph	13,656	0.06%	99.85%	0.03%	99.93%
	Footage of 17 Remaining 3 Phase Underground Primary Conductor Configurations	34,023	0.15%	100.00%	0.07%	100.00%
	Total 3 Phase	**22,445,564**	**100.00%**		**43.12%**	
	Total 1 and 3 Phase	**52,048,950**			**100.00%**	

Configurateion Details Underground Secondary	Total Footage	% of UG Secondary	Cumulative % UG Secondary
6 AL Duplex	5,314,262	44.34%	44.34%
4/0 AL Triplex	3,261,342	27.21%	71.56%
2/0 AL Triplex	900,641	7.52%	79.07%
1/0 AL Triplex	566,227	4.72%	83.80%
350 AL Triplex	382,109	3.19%	86.98%
6 CU Open Wire	350,384	2.92%	89.91%
6 AL Triplex	151,586	1.26%	91.17%
6 CU Triplex	125,589	1.05%	92.22%
8 CU Triplex	123,334	1.03%	93.25%
2 AL Triplex	94,397	0.79%	94.04%
8 CU Open Wire	82,331	0.69%	94.72%
Unknown Unknown Unknown	72,070	0.60%	95.33%
4 CU Open Wire	53,879	0.45%	95.78%
4 CU Triplex	45,804	0.38%	96.16%
8 AL Triplex	27,276	0.23%	96.38%
0 0 Unknown	23,232	0.19%	96.58%
2 Unknown Triplex	19,835	0.17%	96.74%
8 CU Duplex	19,746	0.16%	96.91%
2 Unknown Open Wire	17,030	0.14%	97.05%
2 Unknown Duplex	16,627	0.14%	97.19%
4 CU Duplex	16,573	0.14%	97.33%
4 CU N/A	16,440	0.14%	97.47%
2 AL Duplex	15,606	0.13%	97.60%
4/0 AL Duplex	15,086	0.13%	97.72%
6 AL Open Wire	14,818	0.12%	97.84%
0 0 Duplex	13,775	0.11%	97.96%
6 CU Duplex	11,974	0.10%	98.06%
0 0 Triplex	11,835	0.10%	98.16%
4/0 AL Quadraplex	11,605	0.10%	98.26%
6 CU Unknown	11,569	0.10%	98.35%
Unknown Unknown Duplex	10,588	0.09%	98.44%
6 CU Quadraplex	10,421	0.09%	98.53%
6 CU N/A	10,355	0.09%	98.61%
8 AL Duplex	9,036	0.08%	98.69%
4 AL Triplex	8,333	0.07%	98.76%
1/0 AL Duplex	8,012	0.07%	98.83%
6 Unknown Duplex	7,438	0.06%	98.89%
8 CU N/A	7,423	0.06%	98.95%
4/0 AL Unknown	7,278	0.06%	99.01%
350 AL Duplex	6,918	0.06%	99.07%
Footage of 114 Remaining Underground Secondary Conductor Configurations	111,706	0.93%	100.00%
	11,984,490	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	1 Phase	24,744	42.39%	30.42%	30.42%
1 Phase Wye 25 kVA	1 Phase	18,632	31.92%	22.91%	53.33%
1 Phase Wye 37.5 kVA	1 Phase	9,273	15.89%	11.40%	64.73%
1 Phase Wye 15 kVA	1 Phase	2,480	4.25%	3.05%	67.78%
1 Phase Wye 75 kVA	1 Phase	1,299	2.23%	1.60%	69.37%
1 Phase Wye 100 kVA	1 Phase	1,198	2.05%	1.47%	70.85%
1 Phase Wye 10 kVA	1 Phase	322	0.55%	0.40%	71.24%
1 Phase Wye 167 kVA	1 Phase	206	0.35%	0.25%	71.50%
1 Phase Wye 0 kVA	1 Phase	134	0.23%	0.16%	71.66%
1 Phase Delta 50 kVA	1 Phase	32	0.05%	0.04%	71.70%
1 Phase Wye 250 kVA	1 Phase	16	0.03%	0.02%	71.72%
Number of Transformers for 18 Remaining Single Phase Transformer Configurations		35	0.06%	0.04%	
Total 1 Phase Transformers		58,371	100.00%	71.76%	

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	2 Phase	294	31.85%	0.36%	72.12%
2 Phase Wye/Delta 125 kVA	2 Phase	175	18.96%	0.22%	72.34%
2 Phase Wye/Delta 204.5 kVA	2 Phase	116	12.57%	0.14%	72.48%
2 Phase Wye/Delta 50 kVA	2 Phase	61	6.61%	0.07%	72.56%
2 Phase Wye/Delta 300 kVA	2 Phase	59	6.39%	0.07%	72.63%
2 Phase Wye/Delta 100 kVA	2 Phase	35	3.79%	0.04%	72.67%
2 Phase Wye/Delta 62.5 kVA	2 Phase	32	3.47%	0.04%	72.71%
2 Phase Wye/Delta 150 kVA	2 Phase	23	2.49%	0.03%	72.74%
2 Phase Wye/Delta 30 kVA	2 Phase	23	2.49%	0.03%	72.77%
2 Phase Wye/Delta 87.5 kVA	2 Phase	14	1.52%	0.02%	72.79%
Number of Transformers for 26 Remaining 2 Phase Transformer Configurations		91	9.86%	0.11%	72.90%
Total 2 Phase Transformers		923	100.00%	1.13%	

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 Phase	3,569	16.19%	4.39%	77.29%
3 Phase Wye/Wye 300 kVA	3 Phase	3,453	15.66%	4.25%	81.53%
3 Phase Wye/Wye 75 kVA	3 Phase	3,365	15.26%	4.14%	85.67%
3 Phase Wye/Wye 500 kVA	3 Phase	2,889	13.11%	3.55%	89.22%
3 Phase Wye/Wye 112 kVA	3 Phase	2,094	9.50%	2.57%	91.79%
3 Phase Wye/Wye 225 kVA	3 Phase	1,874	8.50%	2.30%	94.10%
3 Phase Wye/Wye 750 kVA	3 Phase	1,506	6.83%	1.85%	95.95%
3 Phase Wye/Wye 1000 kVA	3 Phase	974	4.42%	1.20%	97.15%
3 Phase Wye/Wye 1500 kVA	3 Phase	856	3.88%	1.05%	98.20%
3 Phase Wye/Wye 45 kVA	3 Phase	536	2.43%	0.66%	98.86%
3 Phase Wye/Wye 2000 kVA	3 Phase	443	2.01%	0.54%	99.40%
3 Phase Wye/Wye 2500 kVA	3 Phase	113	0.51%	0.14%	99.54%
3 Phase Wye/Wye 0 kVA	3 Phase	64	0.29%	0.08%	99.62%
3 Phase Wye/Delta 300 kVA	3 Phase	27	0.12%	0.03%	99.65%
3 Phase Wye/Delta 500 kVA	3 Phase	23	0.10%	0.03%	99.68%
Number of Transformers for 65 Remaining 3 Phase Transformer Configurations		259	1.17%	0.32%	100.11%
Total 3 Phase Transformers		22,045	100.00%	27.10%	
Total All Underground Transformers		81,339		100.00%	

Inventory of Overhead Primary by Conductor Configuration

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	10,859,454	26.74%	26.74%	15.47%	15.47%
	2 ACSR 1ph	9,678,158	23.83%	50.56%	13.79%	29.25%
	6A CUWD 1ph	8,014,369	19.73%	70.29%	11.42%	40.67%
	6 CU 1ph	6,987,194	17.20%	87.50%	9.95%	50.62%
	3/10 CU 1ph	1,648,191	4.06%	91.55%	2.35%	52.97%
	Unknown Unknown 1ph	811,788	2.00%	93.55%	1.16%	54.13%
	4 CU 1ph	760,417	1.87%	95.43%	1.08%	55.21%
	2/0 ACSR 1ph	235,097	0.58%	96.00%	0.33%	55.55%
	3/8 CU 1ph	218,309	0.54%	96.54%	0.31%	55.86%
	8A CUWD 1ph	172,486	0.42%	96.97%	0.25%	56.10%
	2 CU 1ph	145,310	0.36%	97.32%	0.21%	56.31%
	1/0 ACSR 1ph	138,229	0.34%	97.66%	0.20%	56.51%
	Unknown CU 1ph	133,578	0.33%	97.99%	0.19%	56.70%
	130 Steel 1ph	90,440	0.22%	98.22%	0.13%	56.82%
	4A CUWD 1ph	75,089	0.18%	98.40%	0.11%	56.93%
	1/0 CU 1ph	68,617	0.17%	98.57%	0.10%	57.03%
	336 AL 1ph	55,401	0.14%	98.71%	0.08%	57.11%
	6A CU 1ph	50,587	0.12%	98.83%	0.07%	57.18%
	8 CU 1ph	48,324	0.12%	98.95%	0.07%	57.25%
	336 ACSR 1ph	42,901	0.11%	99.06%	0.06%	57.31%
	Footage of 66 Remaining Single Phase Overhead Primary Conductor Configurations	383,745	0.94%	100.00%	0.55%	57.86%
	Total 1 Phase	40,617,685	100.00%		57.86%	

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	7,078,360	23.92%	23.92%	10.08%	67.94%
	2 ACSR 3ph	5,887,683	19.90%	43.83%	8.39%	76.33%
	336 ACSR 3ph	3,804,835	12.86%	56.69%	5.42%	81.75%
	2/0 ACSR 3ph	2,437,313	8.24%	64.92%	3.47%	85.22%
	4 ACSR 3ph	1,906,163	6.44%	71.37%	2.72%	87.93%
	6 CU 3ph	1,333,107	4.51%	75.87%	1.90%	89.83%
	1/0 ACSR 3ph	845,598	2.86%	78.73%	1.20%	91.04%
	4/0 CU 3ph	831,557	2.81%	81.54%	1.18%	92.22%
	6A CUWD 3ph	806,062	2.72%	84.27%	1.15%	93.37%
	Unknown Unknown 3ph	504,695	1.71%	85.97%	0.72%	94.09%
	4/0 ACSR 3ph	476,335	1.61%	87.58%	0.68%	94.77%
	556 AL 3ph	456,240	1.54%	89.12%	0.65%	95.42%
	4 CU 3ph	409,354	1.38%	90.51%	0.58%	96.00%
	3/8 CU 3ph	350,840	1.19%	91.69%	0.50%	96.50%
	556 ACSR 3ph	313,772	1.06%	92.75%	0.45%	96.95%
	3/10 CU 3ph	303,618	1.03%	93.78%	0.43%	97.38%
	1/0 CU 3ph	229,219	0.77%	94.55%	0.33%	97.71%
	336 AAC 3ph	219,522	0.74%	95.30%	0.31%	98.02%
	3/6 CU 3ph	206,220	0.70%	95.99%	0.29%	98.31%
	2 CU 3ph	157,043	0.53%	96.52%	0.22%	98.54%
	2/0 CU 3ph	154,819	0.52%	97.05%	0.22%	98.76%
	336 CU 3ph	123,373	0.42%	97.46%	0.18%	98.93%
	556 AAC 3ph	120,854	0.41%	97.87%	0.17%	99.10%
	2/0 AL 3ph	84,143	0.28%	98.16%	0.12%	99.22%
	Footage of 68 Remaining 3 Phase Overhead Primary Conductor Configurations	545,045	1.84%	100.00%	0.78%	100.00%
	Total 3 Phase	29,585,771	100.00%		42.14%	
	Total All OH Primary	70,203,456				

Inventory of Overhead Secondary by Conductor Configuration

Configuration Details Overhead Secondary	Total Footage	% of Total Overhead Secondary	Cumulative % Overhead Secondary
2 ACSR Open Wire	18,398,559	23.46%	23.46%
4 ACSR Open Wire	8,445,823	10.77%	34.23%
1/0 ACSR Open Wire	6,875,855	8.77%	43.00%
6A CUWD Open Wire	6,495,877	8.28%	51.28%
6 CU Open Wire	5,944,768	7.58%	58.86%
4 CU Open Wire	5,809,064	7.41%	66.27%
2 CU Open Wire	5,372,600	6.85%	73.12%
1/0 AL Triplex	2,716,408	3.46%	76.58%
1/0 AL Triplex, Lashed	2,703,151	3.45%	80.03%
6 ACSR Duplex	2,501,466	3.19%	83.22%
3/10 CU Open Wire	1,417,755	1.81%	85.03%
1/0 CU Open Wire	1,026,461	1.31%	86.34%
2 AL Triplex	968,987	1.24%	87.57%
Unknown CU Open Wire	882,598	1.13%	88.70%
2/0 ACSR Open Wire	836,644	1.07%	89.76%
2 ACSR N/A	835,222	1.07%	90.83%
6 AL Duplex	748,802	0.95%	91.78%
3/8 CU Open Wire	538,822	0.69%	92.47%
1/0 AL Open Wire	447,898	0.57%	93.04%
2 ACSR Neutral	427,705	0.55%	93.59%
2/0 ACSR Neutral	401,964	0.51%	94.10%
2 AL Open Wire	286,818	0.37%	94.47%
6 AL Triplex	258,183	0.33%	94.79%
Unknown Unknown Unknown	229,020	0.29%	95.09%
3/6 CU Open Wire	199,882	0.25%	95.34%
6 CUWD Open Wire	166,286	0.21%	95.55%
8A CUWD Open Wire	162,708	0.21%	95.76%
2 ACSR Triplex	155,722	0.20%	95.96%
1/0 ACSR Quadraplex	130,745	0.17%	96.13%
4A CUWD Open Wire	127,475	0.16%	96.29%
2/0 CU Open Wire	124,658	0.16%	96.45%
1/0 ACSR Triplex, Lashed	122,346	0.16%	96.60%
2 ACSR Triplex, Lashed	121,566	0.16%	96.76%
4/0 CU Open Wire	107,564	0.14%	96.90%
336 ACSR Open Wire	89,242	0.11%	97.01%
4 AL Open Wire	86,774	0.11%	97.12%
4 ACSR Triplex	76,402	0.10%	97.22%
4/0 AL Triplex	75,490	0.10%	97.31%
Unknown Steel Martin Open Wire	74,760	0.10%	97.41%
8 CU Open Wire	73,538	0.09%	97.50%
Footage of 333 Remaining Overhead Secondary Conductor Configurations	1,958,037	2.50%	
Total OH Secondary	78,423,646	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	32,366	32.45%	32.45%	28.84%	28.84%
1 Phase Wye 10 kVA	19,792	19.85%	52.30%	17.64%	46.48%
1 Phase Wye 37.5 kVA	16,543	16.59%	68.89%	14.74%	61.22%
1 Phase Wye 15 kVA	16,343	16.39%	85.28%	14.56%	75.79%
1 Phase Wye 50 kVA	12,139	12.17%	97.45%	10.82%	86.60%
1 Phase Wye 75 kVA	819	0.82%	98.27%	0.73%	87.33%
1 Phase Wye 100 kVA	550	0.55%	98.82%	0.49%	87.82%
1 Phase Wye 5 kVA	452	0.45%	99.27%	0.40%	88.23%
1 Phase Wye 0 kVA	159	0.16%	99.43%	0.14%	88.37%
1 Phase Wye 3 kVA	126	0.13%	99.56%	0.11%	88.48%
1 Phase Delta Unknown kVA	71	0.07%	99.63%	0.06%	88.54%
1 Phase Wye 167 kVA	60	0.06%	99.69%	0.05%	88.60%
Number of Transformers for 28 Remaining 1 Phase Transformer Configurations	308	0.31%	100.00%	0.27%	88.87%
Total 1 Phase Transformers	99,728	100.00%			

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 75 kVA	651	12.29%	12.29%	0.58%	89.45%
2 Phase Wye/Delta 40 kVA	447	8.44%	20.74%	0.40%	89.85%
2 Phase Wye/Delta 35 kVA	419	7.91%	28.65%	0.37%	90.22%
2 Phase Wye/Delta 20 kVA	315	5.95%	34.60%	0.28%	90.50%
2 Phase Wye/Delta 62.5 kVA	314	5.93%	40.53%	0.28%	90.78%
2 Phase Wye/Delta 52.5 kVA	298	5.63%	46.16%	0.27%	91.05%
2 Phase Wye/Delta 100 kVA	294	5.55%	51.71%	0.26%	91.31%
2 Phase Wye/Delta 65 kVA	282	5.33%	57.03%	0.25%	91.56%
Number of Transformers for 48 Remaining 2 Phase Transformer Configurations	2,275	42.97%	100.00%	2.03%	93.59%
Total 2 Phase Transformers	5,295	100.00%			

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	1,178	16.38%	16.38%	1.05%	94.64%
3 Phase Wye/Wye 150 kVA	919	12.78%	29.16%	0.82%	95.46%
3 Phase Wye/Wye 45 kVA	696	9.68%	38.83%	0.62%	96.08%
3 Phase Wye/Wye 112 kVA	627	8.72%	47.55%	0.56%	96.64%
3 Phase Wye/Wye 300 kVA	448	6.23%	53.78%	0.40%	97.04%
3 Phase Wye/Wye 225 kVA	319	4.44%	58.22%	0.28%	97.32%
3 Phase Wye/Delta 150 kVA	207	2.88%	61.10%	0.18%	97.51%
3 Phase Wye/Wye 30 kVA	207	2.88%	63.97%	0.18%	97.69%
3 Phase Wye/Wye 500 kVA	172	2.39%	66.37%	0.15%	97.84%
3 Phase Wye/Delta 175 kVA	153	2.13%	68.49%	0.14%	97.98%
3 Phase Wye/Delta 125 kVA	138	1.92%	70.41%	0.12%	98.10%
3 Phase Wye/Delta 75 kVA	132	1.84%	72.25%	0.12%	98.22%
3 Phase Wye/Delta 112 kVA	111	1.54%	73.79%	0.10%	98.32%
3 Phase Wye/Delta 100 kVA	100	1.39%	75.18%	0.09%	98.41%
3 Phase Wye/Delta 250 kVA	89	1.24%	76.42%	0.08%	98.49%
Number of Transformers for 110 Remaining 3 Phase Transformer Configurations	1,696	23.58%	100.00%	1.51%	100.00%
Total 3 Phase Transformers	7,192	100.00%		6.41%	
Total OH Transformers	112,215			100.00%	

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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 Transf	**1,471**					$58,201	**$85,614,116**

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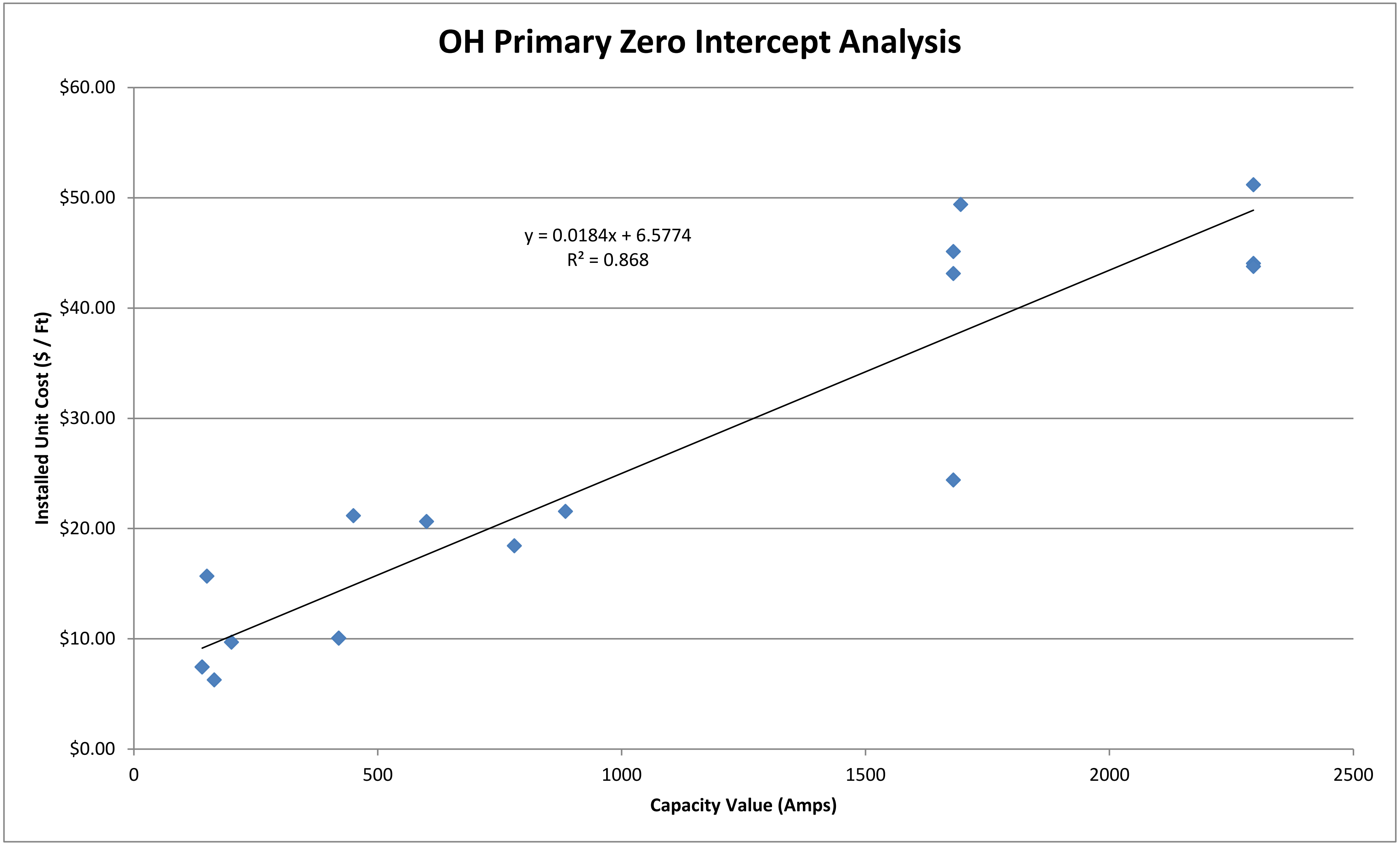
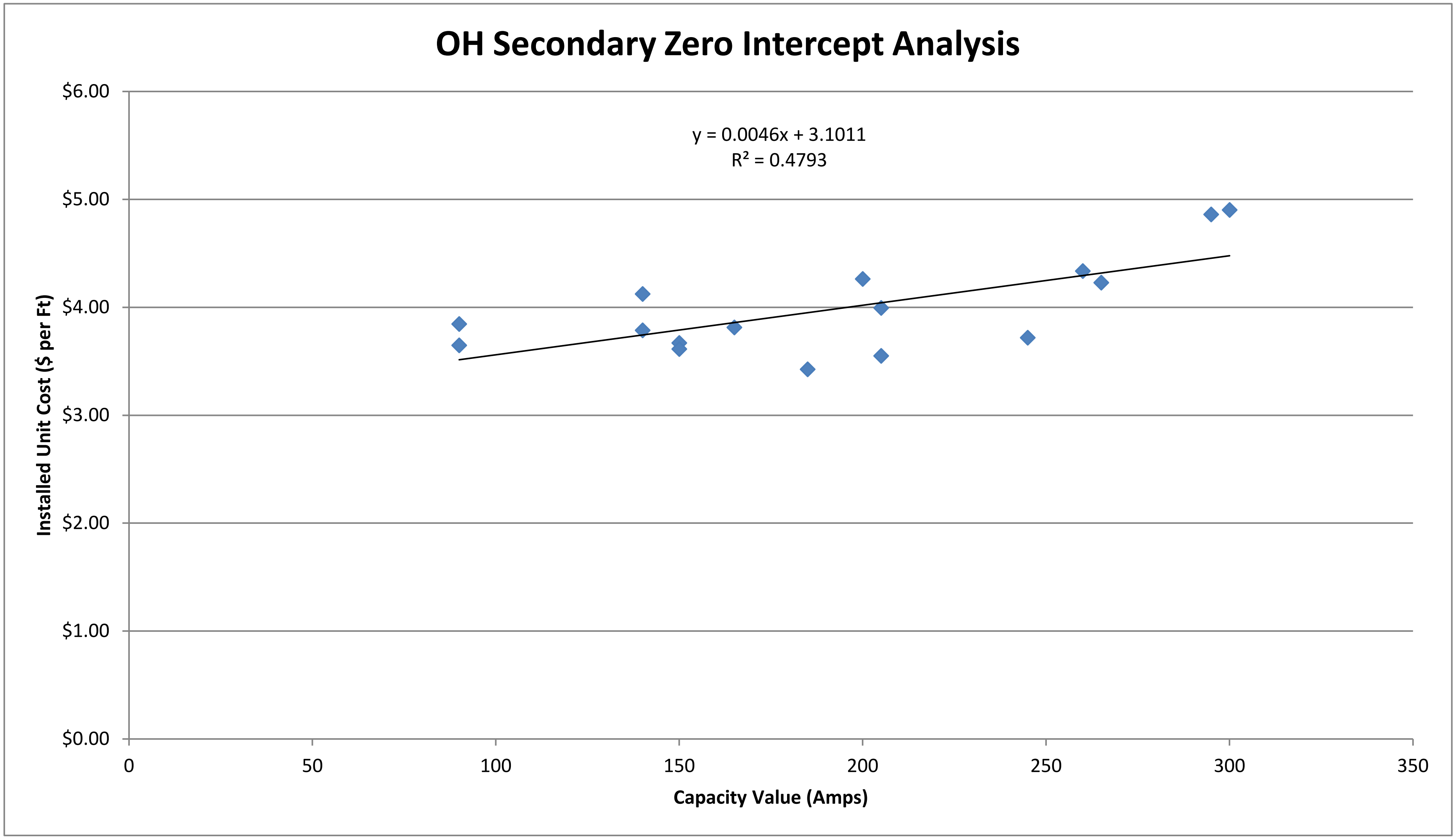
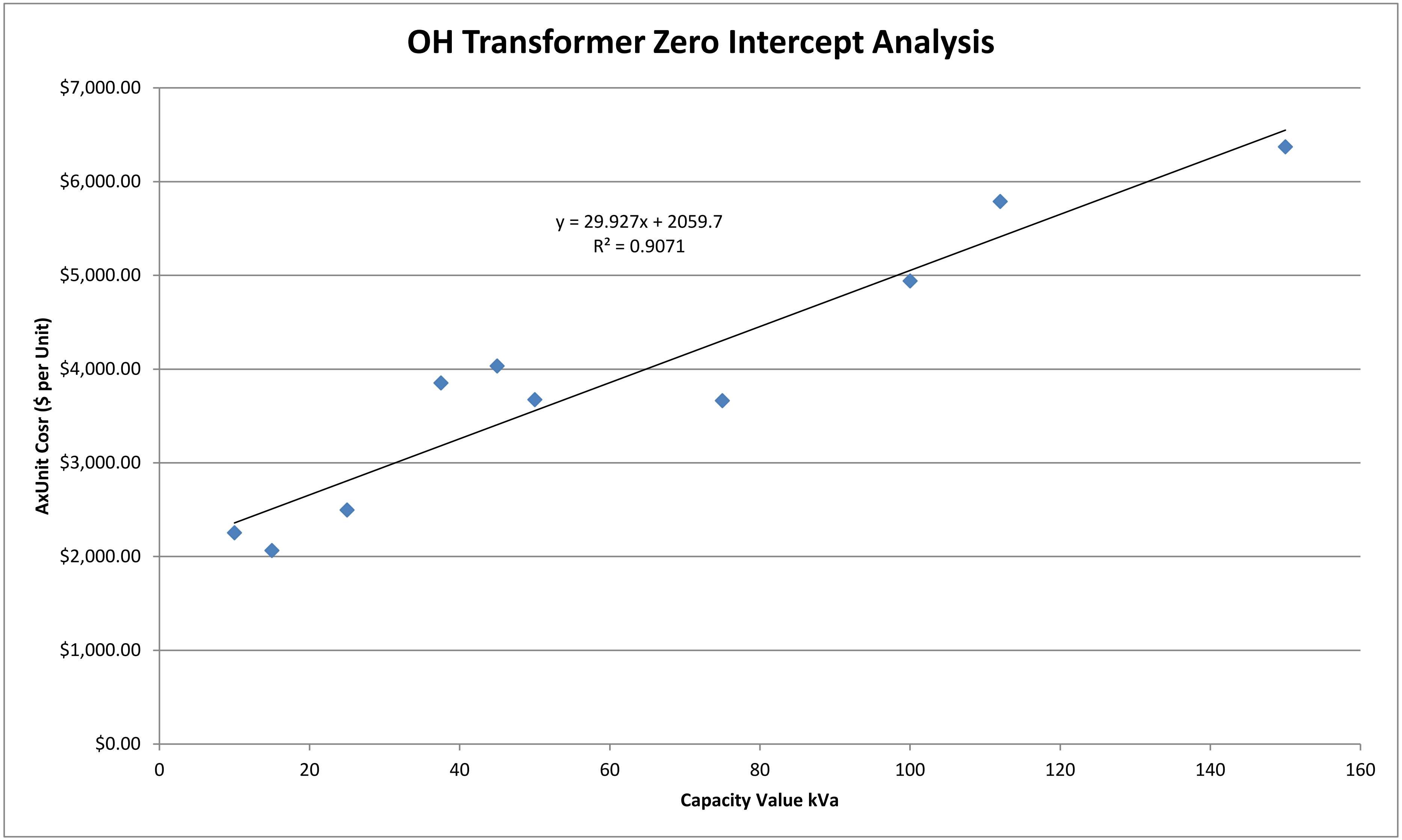
Overhead Primary Zero Intercept Analysis



Northern States Power Company
Overhead Secondary Zero Intercept Analysis

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$6,000.00
$5,000.00
$4,000.00
$3,000.00
$2,000.00
$1,000.00
$0.00
AxUnit Cosr ($ per Unit)
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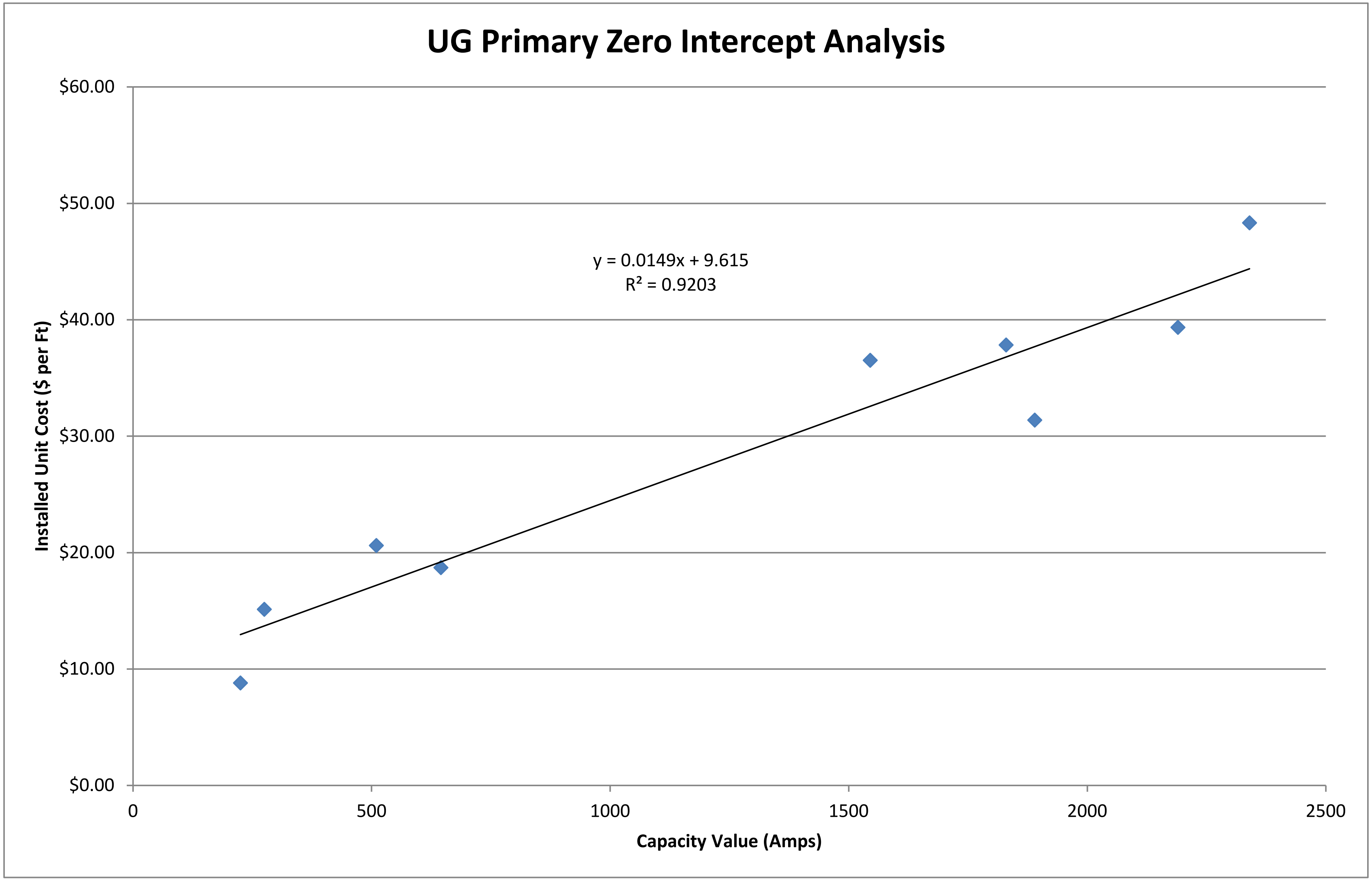
20
40
60
80
100
120
140
160
Capacity Value kVa

Northern States Power Company
Underground Primary Zero Intercept Analysis



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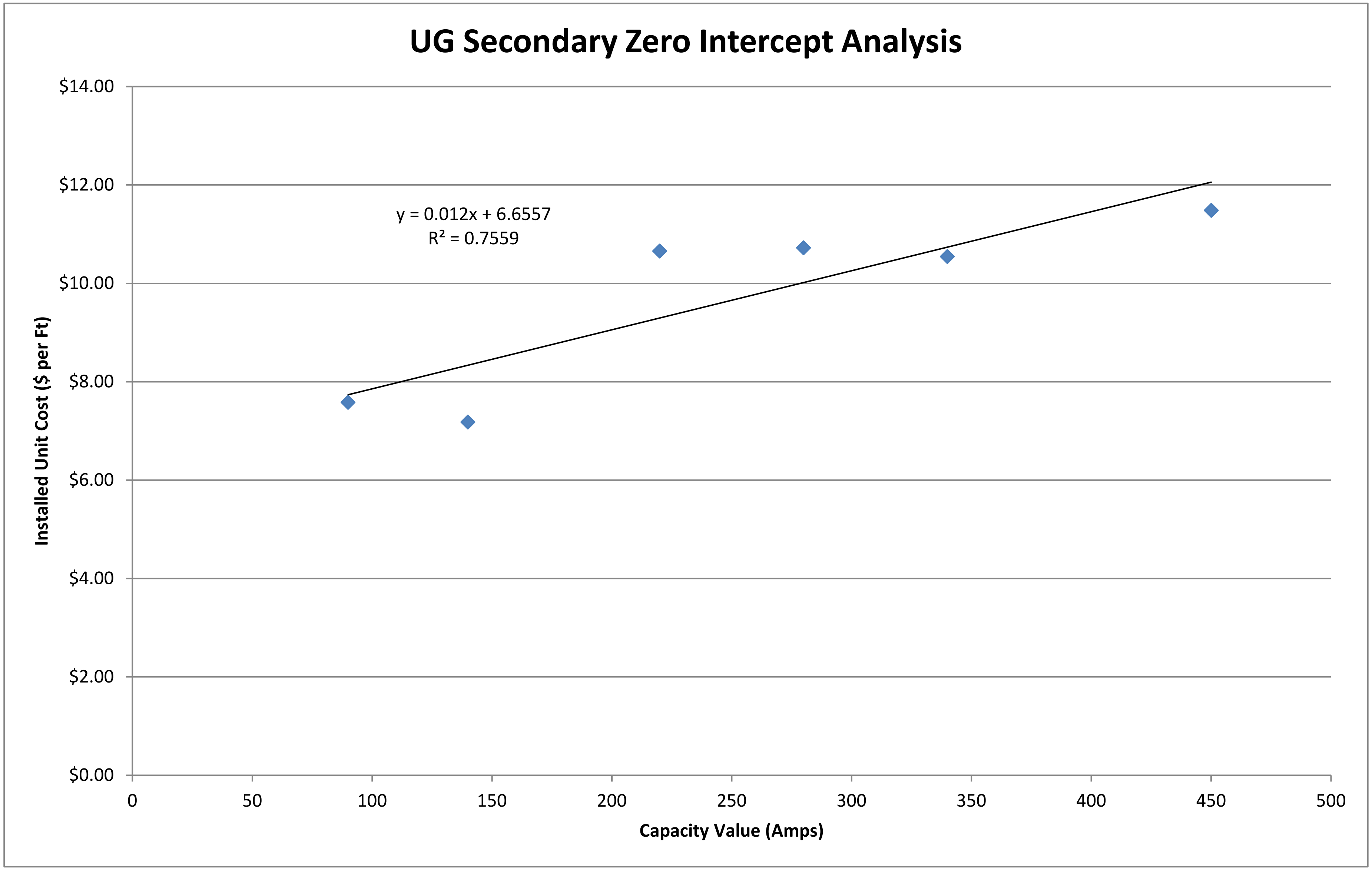
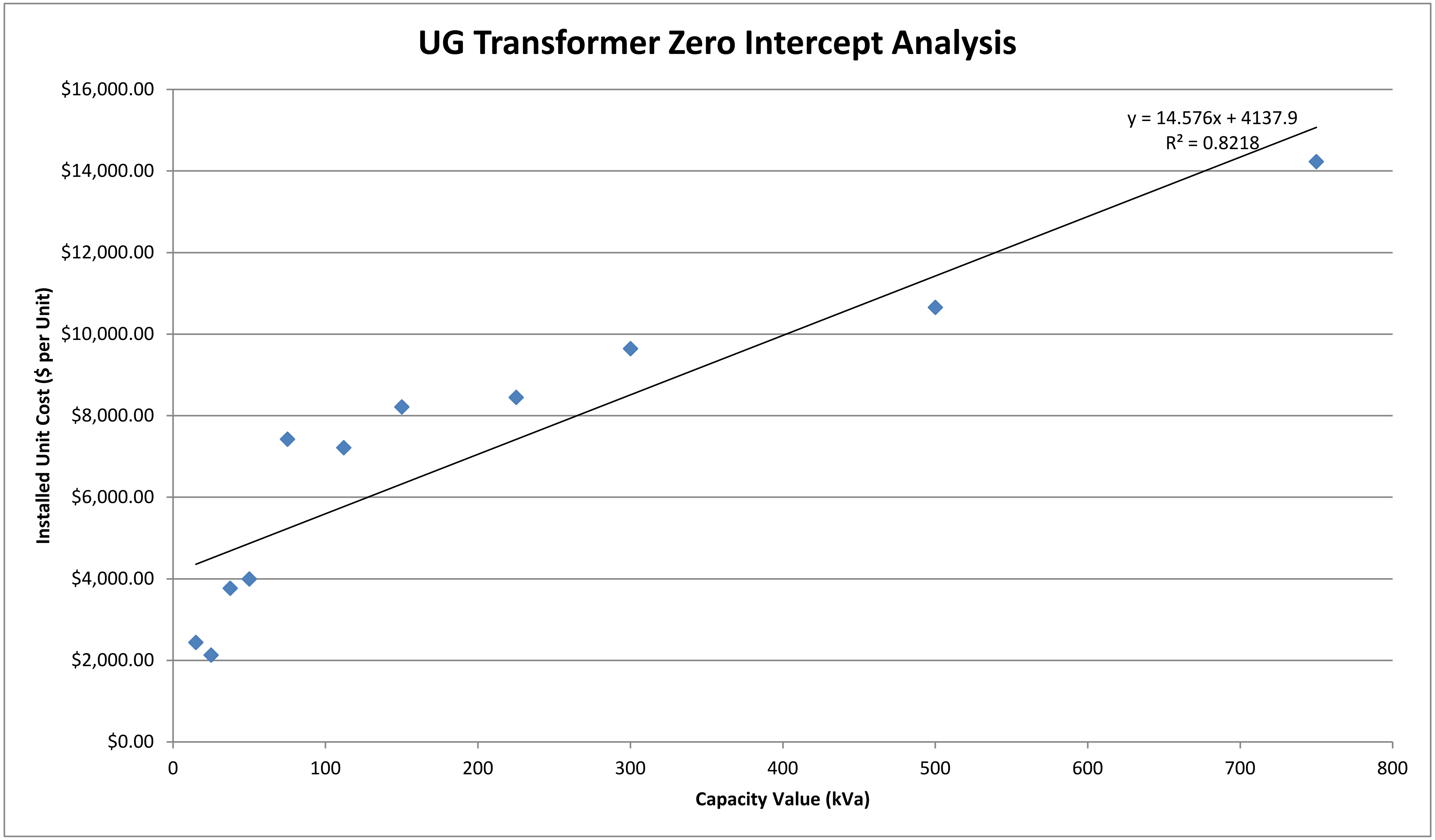
Underground Secondary Zero Intercept Analysis



Northern States Power Company
Underground Transformer Zero Intercept Analysis



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Minimum System / Zero Intercept Distribution System Cost Analysis

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]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9] = [4] x [8]	[10]	[11] = [4] x [10]	[12]	[13] = [4] x [12]
1	OH Primary	1 ph	4 ACSR 1ph	10,859,454	15.5%	15.5%	150	$15.68	$170,305,310	$6.58	$71,455,205	$9.70	$105,283,566
2	OH Primary	1 ph	2 ACSR 1ph	9,678,158	13.8%	29.3%	200	$9.70	$93,830,776	$6.58	$63,682,279	$9.70	$93,830,776
3	OH Primary	1 ph	6A CUWD 1ph	8,014,369	11.4%	40.7%	140	$7.45	$59,692,680	$6.58	$52,734,549	$9.70	$77,700,167
4	OH Primary	1 ph	6 CU 1ph	6,987,194	10.0%	50.6%	140	$7.45	$52,054,593	$6.58	$45,975,734	$9.70	$67,741,590
5	OH Primary	1 ph	3/10 CU 1ph	1,648,191	2.3%	53.0%	165	$6.28	$10,358,351	$6.58	$10,845,100	$9.70	$15,979,393
6			**Total 1 Phase Primary in Sample**	37,187,366				**$10.39**	$386,241,710		$244,692,868		$360,535,492
7	OH Primary	3 ph	336 AL 3ph	7,078,360	10.1%	63.1%	1680	$43.13	$305,312,256	$6.58	$46,575,608	$9.70	$68,625,457
8	OH Primary	3 ph	2 ACSR 3ph	5,887,683	8.4%	71.4%	600	$20.63	$121,491,704	$6.58	$38,740,952	$9.70	$57,081,714
9	OH Primary	3 ph	336 ACSR 3ph	3,804,835	5.4%	76.9%	1695	$49.41	$187,989,678	$6.58	$25,035,814	$9.70	$36,888,281
10	OH Primary	3 ph	2/0 ACSR 3ph	2,437,313	3.5%	80.3%	885	$21.57	$52,580,782	$6.58	$16,037,518	$9.70	$23,630,008
11	OH Primary	3 ph	4 ACSR 3ph	1,906,163	2.7%	83.0%	450	$21.17	$40,353,481	$6.58	$12,542,556	$9.70	$18,480,459
12	OH Primary	3 ph	6 CU 3ph	1,333,107	1.9%	84.9%	420	$10.06	$13,411,056	$6.58	$8,771,843	$9.70	$12,924,614
13	OH Primary	3 ph	6A CUWD 3ph	806,062	1.1%	86.1%	420	$10.06	$8,107,342	$6.58	$5,303,887	$9.70	$7,814,855
14	OH Primary	3 ph	1/0 ACSR 3ph	845,598	1.2%	87.3%	780	$18.44	$15,595,854	$6.58	$5,564,038	$9.70	$8,198,168
15	OH Primary	3 ph	4/0 CU 3ph	831,557	1.2%	88.5%	1680	$24.41	$20,294,478	$6.58	$5,471,643	$9.70	$8,062,031
16	OH Primary	3 ph	556 AL 3ph	456,240	0.6%	89.1%	2295	$43.77	$19,971,291	$6.58	$3,002,058	$9.70	$4,423,294
17	OH Primary	3 ph	556 ACSR 3ph	313,772	0.4%	89.6%	2295	$44.06	$13,823,980	$6.58	$2,064,623	$9.70	$3,042,058
18	OH Primary		336 AAC 3ph	219,522	0.3%	89.9%	1680	$45.14					
19	OH Primary		556 AAC 3ph	120,854	0.2%	90.1%	2295	$51.19					
20	OH Primary		**Total 3 Phase Primary in Sample**	26,041,066				**$30.68**	$798,931,902		$169,110,540		$249,170,939
19	OH Primary		**Total 1 Ph & 3 Ph OH Primary in Sample**	63,228,432				**$18.74**	$1,185,173,613		$413,803,408		$609,706,431
20										**% Customer Related Costs Using Zero Intercept =**	34.92%	**% Customer Related Costs Using Minimum System =**	**51.44%**

Northern States Power Company

Minimum System / Zero Intercept Distribution System Cost Analysis

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]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9] = [4] x [8]	[10]	[11] = [4] x [10]	[12]	[13] = [4] x [12]
21	OH Secondary		2 ACSR Open Wire	18,398,559	23.5%	23.5%	200	$4.26	$78,421,555	$3.10	$57,035,533	$3.55	$65,316,026
22	OH Secondary		4 ACSR Open Wire	8,445,823	10.8%	34.2%	150	$3.61	$30,508,867	$3.10	$26,182,052	$3.55	$29,983,196
23	OH Secondary		1/0 ACSR Open Wire	6,875,855	8.8%	43.0%	260	$4.34	$29,810,243	$3.10	$21,315,150	$3.55	$24,409,710
24	OH Secondary		6 CU Open Wire	5,944,768	7.6%	50.6%	140	$4.12	$24,507,739	$3.10	$18,428,782	$3.55	$21,104,296
25	OH Secondary		6A CUWD Open Wire	6,495,877	8.3%	58.9%	140	$3.79	$24,601,573	$3.10	$20,137,218	$3.55	$23,060,765
26	OH Secondary		4 CU Open Wire	5,809,064	7.4%	66.3%	185	$3.43	$19,904,932	$3.10	$18,008,098	$3.55	$20,622,537
27	OH Secondary		2 CU Open Wire	5,372,600	6.9%	73.1%	245	$3.72	$19,975,072	$3.10	$16,655,061	$3.55	$19,073,064
28	OH Secondary		1/0 AL Triplex	2,716,408	3.5%	76.6%	205	$3.55	$9,643,415	$3.10	$8,420,864	$3.55	$9,643,415
29	OH Secondary		6 ACSR Duplex	2,501,466	3.2%	79.8%	90	$3.65	$9,123,936	$3.10	$7,754,544	$3.55	$8,880,358
30	OH Secondary		1/0 AL Triplex, Lashed	2,703,151	3.4%	83.2%	205	$3.99	$10,795,628	$3.10	$8,379,770	$3.55	$9,596,355
31	OH Secondary		3/10 CU Open Wire	1,417,755	1.8%	85.0%	165	$3.81	$5,406,260	$3.10	$4,395,041	$3.55	$5,033,118
32	OH Secondary		1/0 CU Open Wire	1,026,461	1.3%	86.3%	300	$4.90	$5,032,175	$3.10	$3,182,029	$3.55	$3,644,000
33	OH Secondary		2 AL Triplex	968,987	1.2%	87.6%	150	$3.67	$3,556,408	$3.10	$3,003,860	$3.55	$3,439,964
34	OH Secondary		2/0 ACSR Open Wire	836,644	1.1%	88.6%	295	$4.86	$4,066,091	$3.10	$2,593,597	$3.55	$2,970,139
35	OH Secondary		6 AL Duplex	748,802	1.0%	89.6%	90	$3.84	$2,878,937	$3.10	$2,321,287	$3.55	$2,658,294
36	OH Secondary		1/0 AL Open Wire	447,898	0.6%	90.2%	265	$4.23	$1,894,190	$3.10	$1,388,485	$3.55	$1,590,067
37		**Total OH Secondary in Sample**		70,710,119				**$3.96**	$280,127,022		$219,201,369		$251,025,306
38										**% Customer Related Costs Using Zero Intercept =**	**78.25%**	**% Customer Related Costs Using Minimum System =**	**89.61%**

Northern States Power Company

Docket No. E002/GR-20-723
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**
39	OH Transformers		1 Phase Wye 25 kVA	32,366	28.8%	28.8%	25	$2,497	$80,826,837	$2,060	$66,673,960	$2,253	$72,920,598
40	OH Transformers		1 Phase Wye 10 kVA	19,792	17.6%	46.5%	10	$2,253	$44,584,676	$2,060	$40,771,520	$2,253	$44,591,376
41	OH Transformers		1 Phase Wye 37.5 kVA	16,543	14.7%	61.2%	37.5	$3,851	$63,715,349	$2,060	$34,078,580	$2,253	$37,271,379
42	OH Transformers		1 Phase Wye 15 kVA	16,343	14.6%	75.8%	15	$2,065	$33,751,805	$2,060	$33,666,580	$2,253	$36,820,779
43	OH Transformers		1 Phase Wye 50 kVA	12,139	10.8%	86.6%	50	$3,673	$44,587,443	$2,060	$25,006,340	$2,253	$27,349,167
44	OH Transformers		3 Phase Wye/Wye 75 kVA	1,178	1.0%	87.7%	75	$3,662	$4,314,234	$2,060	$2,426,680	$2,253	$2,654,034
45	OH Transformers		3 Phase Wye/Wye 150 kVA	919	0.8%	88.5%	150	$6,371	$5,854,792	$2,060	$1,893,140	$2,253	$2,070,507
46	OH Transformers		3 Phase Wye/Wye 112 kVA	627	0.6%	89.0%	112	$5,789	$3,629,692	$2,060	$1,291,620	$2,253	$1,412,631
47	OH Transformers		3 Phase Wye/Wye 45 kVA	696	0.6%	89.7%	45	$4,034	$2,807,811	$2,060	$1,433,760	$2,253	$1,568,088
48	OH Transformers		1 Phase Wye 100 kVA	550	0.5%	90.1%	100	$4,941	$2,717,436	$2,060	$1,133,000	$2,253	$1,239,150
49			**Total OH Transformers in Sample**	101,153				**$2,835.21**	**$286,790,075**		**$208,375,180**		**$227,897,709**
50										**% Customer Related Costs Using Zero Intercept =**	**72.66%**	**% Customer Related Costs Using Minimum System =**	**79.46%**
51	UG Primary	1 ph	1/0 AL 1ph	15,663,066	30.1%	30.1%	275	$15.13	$236,951,289	$9.61	$150,522,067	$8.79	$137,715,665
52	UG Primary	1 ph	2 AL 1ph	13,190,012	25.3%	55.4%	225	$8.79	$115,971,630	$9.61	$126,756,019	$8.79	$115,971,630
53			**Total 1 Phase Primary in Sample**	28,853,079				**$12.23**	**$352,922,919**		**$277,278,085**		**$253,687,294**
54													
55	UG Primary	3 ph	1/0 AL 3ph	12,837,974	24.7%	80.1%	645	$18.72	$240,311,035	$9.61	$123,372,928	$8.79	$112,876,372
56	UG Primary	3 ph	750 AL 3ph	4,426,067	8.5%	88.6%	1890	$31.38	$138,910,770	$9.61	$42,534,499	$8.79	$38,915,669
57	UG Primary	3 ph	2 AL 3ph	1,161,402	2.2%	90.8%	510	$20.62	$23,948,111	$9.61	$11,161,074	$8.79	$10,211,491
58	UG Primary	3 ph	1000 AL 3ph	542,869	1.0%	91.9%	2190	$39.34	$21,354,087	$9.61	$5,216,976	$8.79	$4,773,116
59	UG Primary	3 ph	500 AL 3ph	474,292	0.9%	92.8%	1545	$36.51	$17,316,384	$9.61	$4,557,942	$8.79	$4,170,153
60	UG Primary	3 ph	500 CU 3ph	543,913	1.0%	93.8%	1830	$37.84	$20,582,764	$9.61	$5,227,000	$8.79	$4,782,287
61	UG Primary	3 ph	750 CU 3ph	291,013	0.6%	94.4%	2340	$48.32	$14,060,328	$9.61	$2,796,636	$8.79	$2,558,699
62			**Total 3 Phase Primary in Sample**	19,803,238				**$23.19**	**$459,167,097**		**$194,867,055**		**$178,287,786**
63													
64			**Total 1 Ph & 3 Ph UG Primary in Sample**	48,656,316					**$812,090,015**		**$472,145,140**		**$431,975,080**
65										**% Customer Related Costs Using Zero Intercept =**	**58.14%**	**% Customer Related Costs Using Minimum System =**	**53.19%**

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**
66	UG Secondary		6 AL Duplex	5,314,262	44.3%	44.3%	90	$7.58	$40,294,985	$6.66	$35,392,987	$10.66	$56,637,927
67	UG Secondary		4/0 AL Triplex	3,261,342	27.2%	71.6%	340	$10.55	$34,395,627	$6.66	$21,720,539	$10.66	$34,758,477
68	UG Secondary		2/0 AL Triplex	900,641	7.5%	79.1%	280	$10.72	$9,657,679	$6.66	$5,998,268	$10.66	$9,598,779
69	UG Secondary		1/0 AL Triplex	566,227	4.7%	83.8%	220	$10.66	$6,034,686	$6.66	$3,771,070	$10.66	$6,034,686
70	UG Secondary		6 CU Open Wire	350,384	2.9%	86.7%	140	$7.18	$2,516,918	$6.66	$2,333,559	$10.66	$3,734,298
71	UG Secondary		350 AL Triplex	382,109	3.2%	89.9%	450	$11.48	$4,387,853	$6.66	$2,544,848	$10.66	$4,072,415
72		**Total UG Secondary in Sample**		10,774,966				**$9.03**	**$97,287,748**		**$71,761,272**		**$114,836,584**
73										**% Customer Related Costs Using Zero Intercept =**	**73.76%**	**% Customer Related Costs Using Minimum System =**	**100.00%**
74	UG Transformers		1 Phase Wye 50 kVA	24,744	30.4%	30.4%	50	$3,994	$98,835,224	$4,138	$102,390,672	$2,440	$60,385,072
75	UG Transformers		1 Phase Wye 25 kVA	18,632	22.9%	53.3%	25	$2,129	$39,672,528	$4,138	$77,099,216	$2,440	$45,469,393
76	UG Transformers		1 Phase Wye 37.5 kVA	9,273	11.4%	64.7%	37.5	$3,770	$34,954,679	$4,138	$38,371,674	$2,440	$22,629,760
77	UG Transformers		3 Phase Wye/Wye 150 kVA	3,569	4.4%	69.1%	150	$8,212	$29,307,560	$4,138	$14,768,522	$2,440	$8,709,761
78	UG Transformers		3 Phase Wye/Wye 300 kVA	3,453	4.2%	73.4%	300	$9,642	$33,293,491	$4,138	$14,288,514	$2,440	$8,426,675
79	UG Transformers		3 Phase Wye/Wye 75 kVA	3,365	4.1%	77.5%	75	$7,423	$24,979,015	$4,138	$13,924,370	$2,440	$8,211,921
80	UG Transformers		3 Phase Wye/Wye 500 kVA	2,889	3.6%	81.0%	500	$10,656	$30,784,844	$4,138	$11,954,682	$2,440	$7,050,294
81	UG Transformers		1 Phase Wye 15 kVA	2,480	3.0%	84.1%	15	$2,440	$6,052,173	$4,138	$10,262,240	$2,440	$6,052,173
82	UG Transformers		3 Phase Wye/Wye 112 kVA	2,094	2.6%	86.7%	112	$7,217	$15,111,535	$4,138	$8,664,972	$2,440	$5,110,182
83	UG Transformers		3 Phase Wye/Wye 225 kVA	1,874	2.3%	89.0%	225	$8,446	$15,828,535	$4,138	$7,754,612	$2,440	$4,573,296
84	UG Transformers		3 Phase Wye/Wye 750 kVA	1,506	1.9%	90.8%	750	$14,231	$21,431,235	$4,138	$6,231,828	$2,440	$3,675,231
85		**Total UG Transformers in Sample**		73,879				**$4,740.87**	**$350,250,819**		**$305,711,302**		**$180,293,758**
86										**% Customer Related Costs Using Zero Intercept =**	**87.28%**	**% Customer Related Costs Using Minimum System =**	**51.48%**
87		**Total OH and UG Transformers in Sample**		175,032				**$3,640**	**$637,040,895**		**$514,086,482**		**$408,191,467**
88										**% Customer Related Costs Using Zero Intercept =**	**80.70%**	**% Customer Related Costs Using Minimum System =**	**64.08%**

Northern States Power Company
Minimum System / Zero Intercept Analysis Results
Distribution Plant Cost Classification: Capacity Vs Customer Classification
Hybrid Method

		[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						65.08%	$154,519	15.94%
2	OH Primary Single Phase Customer						34.92%	$82,892	8.55%
3	Total OH Primary Single Phase	40,617,685	$10.39	$421,870	25.72%	$237,412	100.00%	$237,412	
4	OH Primary Multi Phase Capacity						65.08%	$332,459	34.29%
5	OH Primary Multi Phase Customer						34.92%	$178,348	18.39%
6	Total OH Primary Multi Phase	29,585,771	$30.68	$907,682	55.34%	$510,807	100.00%	$510,807	
7	OH Secondary Capacity						21.75%	$38,027	3.92%
8	OH Secondary Customer						78.25%	$136,814	14.11%
9	Total OH Secondary	78,423,646	$3.96	$310,685	18.94%	$174,841	100.00%	$174,841	
10	Street Lighting (see Line 9 of Table 12 of Peppin Direct Testimony)					$46,548		$46,548	4.80%
11	Total Overhead (see Schedule 4, Page 4, Column 1, Line 28)			$1,640,238	100.00%	$969,608		$969,608	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						46.81%	$259,180	17.11%
13	UG Primary Single Phase Customer						53.19%	$294,540	19.44%
14	Total UG Primary Single Phase	29,603,387	$12.23	$362,100	36.55%	$553,720	100.00%	$553,720	
15	UG Primary Multi Phase Capacity						46.81%	$372,509	24.59%
16	UG Primary Multi Phase Customer						53.19%	$423,332	27.94%
17	Total UG Primary Multi Phase	22,445,564	$23.19	$520,433	52.53%	$795,841	100.00%	$795,841	
18	UG Secondary Capacity						26.24%	$43,417	2.87%
19	UG Secondary Customer						73.76%	$122,055	8.06%
20	Total UG Secondary	11,984,490	$9.03	$108,209	10.92%	$165,471	100.00%	$165,471	
21	Street Lighting					$0		$0	0.00%
22	Total Underground			$990,742		$1,515,032		$1,515,032	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	10.84%	$32,632	100% Capacity	$32,632	10.84%
24	Secondary Capacity						36.28%	$97,421	32.35%
25	Secondary Customer						63.72%	$171,083	56.81%
26	Total Secondary	193,554	$3,640	$704,453	89.16%	$268,504	100.00%	$268,504	89.16%
27	Total Transformers			$790,067		$301,136		$301,136	100.00%

Northern States Power Company
Minimum System Analysis for Distribution Services

	[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	787,960	$158,774			
2	UG Services	1/0 Triplex	50	$2.81	447,128	$62,822			
3	Total Services				1,235,088	$221,595	$300,504	73.74%	26.26%

Northern States Power Company

Docket No. E002/GR-20-723
Exhibit___(MAP-1), Schedule 11

Test Year Ending December 31, 2021
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	1,313,235	1,173,030	85,927	48,203	473	5,602
2	Capacity Portion of **Multi-Phase** Primary Lines	Class Coincident Peak Demands	D61PS	5,716,588	2,210,106	136,895	2,659,539	691,162	18,887
3	% of Customers Served by Primary **Single Phase** Lines				**73.1%**	**40.5%**	**12.3%**	**15.2%**	**61.2%**
4	Customer Portion of **Single-Phase** Primary Lines	line 1 x line 3	C61PS1Ph	902,043	857,842	34,790	5,908	72	3,431
5	Capacity Portion of Single-Phase Primary Lines	line 2 x line 3	D61PS1Ph	2,114,519	1,616,260	55,426	325,991	105,276	11,566
6	Customer Portion of **Multi-Phase** Primary Lines	Cost Allocator %	C61PS	100.0%	89.3%	6.5%	3.7%	0.0%	0.4%
7	Capacity Portion of **Multi-Phase** Primary Lines	Cost Allocator %	D61PS	100.0%	38.7%	2.4%	46.5%	12.1%	0.3%
8	Customer Portion of **Single-Phase** Primary Lines	Cost Allocator %	C61PS1Ph	100.0%	95.1%	3.9%	0.7%	0.0%	0.4%
9	Capacity Portion of **Single-Phase** Primary Lines	Cost Allocator %	D61PS1Ph	100.0%	76.4%	2.6%	15.4%	5.0%	0.5%

Renewable Programs Capacity Credit Cost Forecast Summary

	2021	**2022**	**2023**	**2024**	**2025**
Windsource	$754,626	$0	$0	$0	$0
Renewable*Connect Month-to-Month	$0	$1,183,125	$1,220,839	$1,200,402	$1,218,178
Renewable*Connect Pilot	$1,364,016	$1,397,928	$1,429,956	$1,465,752	$1,499,664
Renewable*Connect Standard	$0	$986,441	$1,009,804	$1,033,167	$1,056,530
Renewable*Connect High Off-Peak	$0	$1,364,083	$1,396,672	$1,429,261	$1,461,850
Total Capacity Credit	$2,118,642	$4,931,577	$5,057,271	$5,128,581	$5,236,222

		2021	2022	2023	2024	2025
[1]	Levelized CT Carrying Costs	$54.48				
[2]	MISO Accredited Capacity per kW of Wind Capacity [1]	16.60%				
[3]	Costs Avoided (Line 1 * Line 2)	$9.04				
[4]	MW of Wind Capacity					
	Avg Annual Windsource Capacity Factor	31.28%				
[5]	Availaibility Factor	95%				
[6]	Hour/Year	8,760				
[7]	Annual Hour of Operation (Line 4 * Line 5 * Line 6)	2,603				
[8]	**Capacity Credit $ per kWh (Line 3 / Line 7)**	**$0.00347**				
[9]	Wind Generation Forecast (kWh)	217,471,380				
[10]	2016 Windsource Capacity Credit (Line 8 * Line9) [2]	**$754,626**	**$0**	**$0**	**$0**	**$0**

[1] Source: "Planning Year 2020-2021 Wind and Solar Capacity Credit"
https://cdn.misoenergy.org/2020%20Wind%20&%20Solar%20Capacity%20Credit%20Report408144.pdf
[2] This Windsource Credit is included in the TY2021 Revenue Requirement

Renewable*Connect Pilot Capacity Credit

		2021	2022	2023	2024	2025
[1]	Renewable*Connect Month-to-Month Sales (kWh)		226,219,000	224,419,000	222,709,000	221,085,000
[2]	Capacity Credit $ per kWh		0.00523	0.00544	0.00539	0.00551
[3]	**Total Renewable*Connect Capacity Credit (Line 1 * Line 2)**	**$0**	**$1,183,125**	**$1,220,839**	**$1,200,402**	**$1,218,178**

		2021	2022	2023	2024	2025
[1]	Renewable*Connect Pilot Sales (kWh)	178,000,000	178,000,000	178,000,000	178,000,000	178,000,000
[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)	188,400,000	188,400,000	188,400,000	188,400,000	188,400,000
[4]	Capacity Credit $ per kWh	$0.00724	0.00742	0.00759	0.00778	0.00796
[5]	**Total Renewable*Connect Capacity Credit (Line 3 * Line 4)**	**$1,364,016**	**$1,397,928**	**$1,429,956**	**$1,465,752**	**$1,499,664**

Renewable*Connect - Standard Capacity Credit

		2021	2022	2023	2024	2025
[1]	Renewable*Connect - Standard Sales (kWh)	0	259,589,674	259,589,674	259,589,674	259,589,674
[2]	Capacity Credit $ per kWh	$0.00000	$0.00380	$0.00389	$0.00398	$0.00407
[3]	**Renewable*Connect Capacity Credit (Line 1 * Line 2)**	**$0**	**$986,441**	**$1,009,804**	**$1,033,167**	**$1,056,530**

Northern States Power Company

Renewable*Connect - High Off-Peak Capacity Credit

		2021	2022	2023	2024	2025
[1]	Renewable*Connect - High Off-Peak Sales (kWh)	0	465,557,341	465,557,341	465,557,341	465,557,341
[2]	Capacity Credit $ per kWh	$0.00000	$0.00293	$0.00300	$0.00307	$0.00314
[3]	**Total Renewable*Connect Capacity Credit (Line 1 * Line 2)**	**$0**	**$1,364,083**	**$1,396,672**	**$1,429,261**	**$1,461,850**

Northern States Power Company

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

TY21 -2021 Proposed CIP Budget[1]	
Business	$ 54,174,646
Residential	$ 28,916,811
Low-Income	$ 2,841,907
Planning	$ 11,425,187
Research, Evaluations, & Pilots	$6,455,634
Regulatory Assessments	$1,974,981
EUI	$ 0
Alternative Filings	$19,815,245
2021 Filed CIP Budget	**$ 125,604,411**
TY21 kWh	
TY 2021 MN kWh Sales	27,377,491,263
TY 2021 CIP Exempt Cust Sales (Est.)	1,200,196,568
Net CIP Sales	26,177,294,695

CCRC = TY21 CIP Expense / TY2021 kWh Sales **0.4798** **¢ per kWh**

	Current	TY 2021	Difference
CCRC (cents/kWh)	**0.3133** [2]	**0.4798** [3]	0.1665
CIP Adjustment Factor (cents/kWh)	**0.1848** [4]	**0.0183** [5]	-0.1665
Total (cents/kWh)	0.4981	0.4981	0

[1] The 2021 CIP Budget was filed with the 2021-2023 CIP Triennial Plan on July 1, 2020 in Docket No. E,G002/CIP-20-473

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

[3] The 0.4590 cents/kWh CCRC for TY 2021 determined above.

[4] The 0.1848 cents/kWh CIP Adjustment Factor for 2020/2021 was approved by MPUC on August 28, 2020 in Docket No. E002/M-20-402.

[5] The 0.0391 cents/kWh CIP Adjust Factor for TY 2021 determined as shown above: (0.1848 CIP Adjust minus 0.1457 Difference in CCRC).

Norhern States Power Company
Electric Utility - Minnesota
Test Year Ending December 31, 2021
Excess Footage and Winter Construction Revenue Impact

Tariff	Description	Present Price	Proposed Price	2018 Units	Present $	Proposed $	Difference
5.1	**Standard Installation and Extension Rules**						
	Excess service charge - Services	$7.90	$12.50	46,324	$365,960	$579,050	$213,090
	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	930	$558,000	$637,050	$79,050
	Per Trench Foot	$3.80	$8.90	73,454	$279,125	$653,741	$374,615
			REVENUE IMPACT		**$1,203,085**	**$1,869,841**	**$666,755.80**

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**

220 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

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										
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											
1												
2												
3												
4												
5												

HIGHLY CONFIDENTIAL TRADE SECRET ENDS]

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Northern States Power Company
CRR - Incremental Cost Analysis

Docket No. E002/GR-20-723
Exhibit___(MAP-1), Schedule 15

		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											
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HIGHLY CONFIDENTIAL TRADE SECRET ENDS]

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	[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS											
1												
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HIGHLY CONFIDENTIAL TRADE SECRET ENDS]