REVISED Direct Testimony and Schedules
Michael A. Peppin

Before the North Dakota Public Service Commission
State of North Dakota

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

Case No. PU-20-441
Exhibit___(MAP-1)

Class Cost of Service Study

March 26, 2021

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Revised prefiled Direct Testimony of Michael Peppin
Northern States Power Company
Greg Chamberlain

Table of Contents

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 DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. My qualifications include nearly 40 years of experience with Xcel Energy 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. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of Xcel Energy.

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

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

II. CLASS COST OF SERVICE STUDY

A. Overview of Proposed Class Cost of Service Study

Q. HOW DOES THE COMPANY'S PROPOSED CCOSS COMPARE WITH THAT APPROVED BY THE NORTH DAKOTA PUBLIC SERVICE COMMISSION IN THE COMPANY'S LAST GENERAL ELECTRIC RATE CASE, CASE NO. PU-12-813?

A. We updated the Company's proposed CCOSS to reflect 2021 forecast data. Specifically, all costs have been updated to reflect 2021 weather normalized costs. The hourly load data, energy use data, and customer-related data have also been updated to reflect forecast weather normalized sales data for 2021, and has been used to update class cost allocation factors. All cost classification and allocation methods are the same as those approved by the Commission in the Company's last rate case, except for the following four refinements:

- A reevaluation of the distribution costs that are directly assigned to the Street Lighting class;
- A separation of the investment in overhead and underground primary distribution lines into separate categories for single-phase and multi-phase lines;
- An update to the analysis used to separate distribution plant costs into customer and capacity related components; and
- A reevaluation of how Other Production O&M costs are classified into capacity and energy components.

The reason for these refinements will be discussed later in my testimony. Other than these refinements, all cost allocation methods are the same as those approved by the Commission in the Company's 2012 rate case.

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

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

- Residential;
- Commercial Non-Demand Billed;
- Commercial and Industrial (C&I) Demand Billed; and

- Street Lighting.

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

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

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

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

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

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

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

- 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;
- Recognizes the differing impact that seasonal and time usage patterns can have on the cost of service; and
- Recognizes that certain distribution costs are incurred simply to supply service to customers regardless of the kW load they demand.

B. CCOSS Results

Q. PLEASE SUMMARIZE THE RESULTS OF THE 2021 CCOSS.

A. Table 1 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. Paluck). A summary of the CCOSS results at the class level is also provided in Exhibit___(MAP-1), Schedule 3. However, for comparison purposes, Schedule 3 also provides the class revenue allocation proposed by Mr. Paluck. The detailed 2021 CCOSS output is shown in Exhibit___(MAP-1), 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 1
Summary of 2021 Class Cost of Service Study
NSPM-North Dakota Electric Jurisdiction
($ Thousands)

UNADJUSTED COST RESPONSIBILITIES

		Total	Resid	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	225,570	90,717	11,587	120,411	2,854
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	44	38	1	4	0
[3]	Unadjusted Operating Revenues (line 1 + line 2)	225,613	90,756	11,589	120,415	2,854
[4]	Present Rates (CCOSS page 2, line 2)	206,416	83,739	11,379	109,232	2,066
[5]	Unadjusted Deficiency (line 3 - line 4)	19,197	7,016	209	11,183	788
[6]	Defic / Pres (line 5 / line 4)	9.3%	8.4%	1.8%	10.2%	38.2%
[7]	**Ratio: Class % / Total %**	**1.00**	**0.90**	**0.20**	**1.10**	**4.10**

COST RESPONSIBILITIES FOR RATE DISCOUNTS

		Total	Resid	Non-Demand	Demand	Street Ltg
[8]	Interruptible Rate Discounts (CCOSS page 2, line 5)	4,207	799	58	3,350	0
[9]	Interruptible Rate Disc Cost Allocation (CCOSS page 2, line 7)	4,207	1,415	188	2,591	13
[10]	Revenue Requirement Change (lines 10 & 11 - lines 8 & 9)	0	616	130	(759)	13

ADJUSTED COST RESPONSIBILITIES

		Total	Resid	Non-Demand	Demand	Street Ltg
[11]	Adjusted Rate Revenue Reqt (line 1 + line 10)	225,570	91,334	11,717	119,652	2,867
[12]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	44	38	1	4	0
[13]	Adjusted Operating Revenues (line 11 + line 12)	225,613	91,372	11,718	119,656	2,867
[14]	Present Rates (line 4)	206,416	83,739	11,379	109,232	2,066
[15]	Adjusted Deficiency (line 13 - line 14)	19,197	7,633	339	10,424	801
[16]	Defic / Pres Rates (line 15 / line 14)	9.3%	9.1%	3.0%	9.5%	38.8%
[17]	**Ratio: Class % / Total %**	**1.00**	**0.98**	**0.32**	**1.03**	**4.17**

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

A. The distinction between "unadjusted" and "adjusted" cost responsibilities relates to how the cost of interruptible rate discounts are reflected in the CCOSS. The method used to reflect the cost of the interruptible rate discounts is the same as that used in the Company's last four 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 or uninterrupted loads. As explained in previous cases, the Company views interruptible service as firm service with an attached, after-the-fact, purchased-power contract provision. Through this provision, the Company has the option to buy back all or part of a customer's regulatory entitlement to firm service. The resulting capacity purchase transactions occur when, and if, doing so is a cost-effective source of peaking capacity; this helps the Company obtain a reliable power supply portfolio at the lowest cost. This means interruptible rate discounts are really capacity-related power supply costs and they need to be recognized as such in the CCOSS.

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

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

1. Line 8 on Table 1 above and Schedule 3, labeled "Interruptible Rate Discounts" shows the amount of the total interruptible rate discounts originating from each class. The amounts shown for each class are lost revenues from that class. These discounts reduce the revenue received

from the classes and thus have the effect of increasing the revenue requirement for the classes that receive the discounts.

2. Line 9 on Table 1 above and Schedule 3, labeled "Interruptible Rate Disc. Cost Allocation" shows how the cost of interruptible rate discounts are allocated to the classes. Interruptible rate discounts are allocated using the applicable generation capacity cost allocation factor.
3. Line 10 on Table 1 above and Schedule 3, labeled "Revenue Requirement Change" shows the net change in the revenue requirement for each customer class.
4. The resulting Line 11 on Table 1 above and Schedule 3, labeled "Adjusted Rate Revenue Requirement" shows the appropriate cost of service for determining class revenue responsibilities. Finally, the adjusted revenue deficiency and percent deficiency are shown on lines 15 and 16, respectively.

C. Production Plant Stratification

Q. A SIGNIFICANT PORTION OF THE COMPANY'S TOTAL COSTS ARE DRIVEN BY FIXED PRODUCTION PLANT. DESCRIBE THE PROCESS THE COMPANY USES FOR ALLOCATING FIXED PRODUCTION PLANT COSTS.

A. The Company classifies fixed production plant into capacity versus energy-related sub-functions using a process called "Plant Stratification." Though refined over the years, this is the same process the Company has used with Commission approval since the late 1970s. This process has also been referred to in the NARUC manual as the Equivalent Peaker method. This allocation method is also supported by the Commissions in Minnesota and South Dakota.

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

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

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

A. Yes. As shown in Table 2 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 2 below. Table 2 compares the current-dollar replacement costs of each plant type towards developing stratification percentages.

Table 2

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	$2,287	$942 / $2,287	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 rate base component (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 capital costs of baseload and intermediate plants are incurred to obtain fuel savings that more than offset the higher fixed costs, thereby minimizing total costs.

D. Classification and Allocation of Distribution Plant Costs

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

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

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

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

As shown on page 4, line 47 of Schedule 4, we directly assigned $3.2 million of FERC Account 373 costs to the Street Lighting class in the 2021 CCOSS. This direct assignment is appropriate because the costs included in FERC Account 373 are directly attributable to Street Lighting.

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

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

Q. WHAT COSTS ARE INCLUDED IN FERC ACCOUNT 364?

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

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

A. Yes. FERC Account 364 includes the cost of 432,896 wooden poles. Company-owned street lights are attached to 91,441 of these poles, meaning 21.12 percent of the Account 364 costs are at least partially attributable to street lighting. Through consultation with our Street Lighting staff, we determined that 60 percent of the lighting poles serve only Street Lighting customers (*i.e.* they do not have facilities attached that serve other customer classes). Since these poles are only used for street lighting, it's appropriate to assign the cost of these poles to the Street Lighting Class. Line 9 of Table 3 below estimates lighting pole costs that should be direct assigned to the Street Lighting class. This direct assignment is also shown in Exhibit___(MAP) Schedule 4 on page 4, line 27.

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

Line No.		
1	FERC 364	$19,020
2	FERC 365	$23,964
3	Total FERC 364 and 365 (line 1 + line 2) *	$42,984
4	MN Company-Owned Street Lights on Wooden Poles	91,441
5	Total MN Poles	432,869
6	Lighting Poles as % of Total Poles (line 4 / line 5)	21.12%
7	Lighting % x FERC 364 (line 1 x line 6)	$4,018
8	Percent of Lighting Poles that only Serve Lighting	60%
9	FERC Acct 364 Direct Assignment to Lighting (line 7 x line 8)	$2,411

*See Exhibit___(MAP-1) Schedule 4 at page 4, line 28.

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

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

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

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

A. Yes. Based on the data in the Company's Geographic Information System, the Company's Distribution staff determined 71.6 percent of North Dakota residential customers receive service off the single-phase primary distribution system. Table 4 also shows that significantly fewer C&I customers receive service from the single-phase primary distribution system.

Table 4

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

Primary Distribution Line Serving the Customer Premise	Customer Class			
	Residential Customers	C&I Non-Demand	C&I Demand	Lighting Customers
Single-Phase	71.6%	40.3%	13.9%	44.0%
Multi-Phase	28.4%	53.7%	86.1%	56.0%
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 Guide to Class Cost of Service Study. In the current 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 5 shows how these allocators were developed.

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

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

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

Table 5

Classification of Distribution Plant Investment

Distribution Plant Property Unit	TY 2021 ND Plant Investment ($000)	Demand Component	Capacity Component
Distribution Substations	$38,649	X	
Primary Voltage Transformers	$2,988	X	
Primary Voltage Distribution Lines	$102,706	X	X
Secondary Voltage Distribution Lines	$16,246	X	X
Secondary Voltage Transformers	$24,585	X	X
Services	$15,226	X	X

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

A. Since the 1990s, the Company has used a Minimum System Study to do this separation. In this case, we updated that study and included three new updates. First, we performed an extensive review of what equipment would be considered "minimum." Second, we performed an extensive review of the installed cost of distribution equipment. 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.

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.

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
    - Primary Voltage Stepdown Transformers
- For each of the above property units, the equipment inventory is obtained for each property unit configuration.
- The maximum capacity rating for each property unit configuration.
    - Ampacity for conductors
    - kVa for Transformers
- The installed cost per unit for the most common property unit configurations.

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

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

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

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

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

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

Q. AS DESCRIBED ABOVE, BOTH MINIMUM SYSTEM AND ZERO INTERCEPT STUDIES REQUIRE DATA ON THE INVENTORY OF DIFFERENT DISTRIBUTION PROPERTY UNIT CONFIGURATIONS, THE MINIMUM SIZE OF DISTRIBUTION

EQUIPMENT CURRENTLY INSTALLED, AND THE PER UNIT INSTALLED COSTS OF DIFFERENT CONFIGURATIONS AND ASSOCIATED LOAD CARRYING CAPACITIES. HOW DID THE COMPANY ACQUIRE THIS INFORMATION?

A. 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 of nearly 12,000 distribution work orders that were completed over an 11 year period. 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). More detail on the specific data sources is provided in Schedule 6.

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

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

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

A. For each property unit, the table below shows the percent of costs that would be classified as customer-related using the Zero Intercept method compared to the Minimum System method. As shown in Table 6 below, for 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 6

% of Distribution Investment Classified as Customer Related

Zero Intercept Method vs. Minimum System Method

Property Unit	**% of Costs Classified as Customer-Related**	
	Zero Intercept Method	**Minimum System Method**
Overhead Primary	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 RESULTS WERE USED IN THE COMPANY'S PROPOSED CCOSS?

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

Table 7

Customer versus Capacity Classification Applied to Distribution Plant Investment

Property Unit	**% Classified as Customer-Related**	**% Classified as Capacity-Related**
Overhead Primary (used Zero Intercept result)	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*	63.7%	36.3%

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

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.

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

Q. EARLIER YOU MENTIONED THERE HAS BEEN A CHANGE TO THE METHOD USED TO ALLOCATE OTHER PRODUCTION O&M COSTS. WHAT METHOD DID THE COMPANY USE IN ITS LAST NORTH DAKOTA RATE CASE?

A. In the last rate case, the Company split Other Production O&M costs into capacity versus energy components based on how Production plant investment (excluding nuclear fuel) was split using the Company's plant stratification analysis as shown on Lines 3 and 4 on Page 4 of Schedule 4.

Q. WHY DID THE COMPANY MAKE A CHANGE TO THE METHOD USED TO ALLOCATE OTHER PRODUCTION O&M COSTS?

A. Upon further examination, it was determined that some plant types, such as the nuclear plants, account for a disproportionate share of Other Production O&M costs.

Q. WHAT WAS THE IMPROVEMENT THAT WAS MADE TO THE CLASSIFICATION OF NON-FUEL PRODUCTION O&M COSTS?

A. The first step was to discuss the nature of the different types of costs with plant operations personnel to identify any non-fuel O&M costs that vary directly with the plant's energy output and classify these costs as 100% energy-related. The costs of chemicals and water use were the only costs that fit into this 100% variable category and were therefore classified as being 100% energy-related.

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

A. Since there was no definitive classification as to the fixed or variable nature of O&M costs, the remaining production O&M costs were separated based on the particular plant type that the specific cost originated from. For example, costs that originated from the Company's Prairie Island plant were put into a nuclear category, costs attributed to Sherco in a fossil category, and so on for the other plant types.

The next step was to apply the capacity and energy-related percentages that resulted from the Company's plant stratification analysis. These percentages are shown in Table 2 and were applied to each category of Non-Fuel Production O&M expense. Costs classified as capacity-related were allocated to customer class using the Commission-approved D10C capacity allocator, while costs classified as energy-related were allocated to customer class using the Commission-approved E8760 allocator.

Q. HOW DOES THE COMPANY CLASSIFY O&M COSTS THAT CAN'T BE ASSIGNED TO A PARTICULAR PLANT TYPE?

A. For those production expenses that do not apply to a particular generation type, the Company applies the weighted average Capacity versus Energy percentage splits for those costs that do originate from a particular type of generation plant

Q. HOW IS THIS METHOD FOR CLASSIFYING NON-FUEL PRODUCTION O&M EXPENSE AN IMPROVEMENT OVER THE METHOD THAT THE COMPANY USED IN ITS LAST RATE CASE?

A. First, for each expense, it identifies which plant type the expense originated from. It also recognizes the fact that for most expenses, there isn't a black and white distinction as to an expense being 100 percent fixed or 100 percent variable in nature. Although there is a fixed component to many cost types such as labor, it recognizes that many costs can increase as usage of a particular plant type increases. This method also extends the application of the Company's stratification approach, which is also supported by the Commissions in Minnesota and South Dakota. It also recognizes the fact that the role of combustion turbines (CTs) is for providing needed capacity during peak demands. As a result, all O&M expenses from CTs should be treated a capacity-related. Table 8 below shows the resulting classification of Other Production O&M expenses. As shown below, 78.93 percent of costs are classified as energy-related while 21.07 percent of costs are classified as capacity-related.

Table 8

Classification of Other Production O&M Costs

NSPM-North Dakota Jurisdiction

Plant Type or Expense Type	2021 Other Prod O&M	Percent Energy	Percent Capacity	Energy-Related	Capacity-Related
Variable (Chemicals & Water Use)	$385,563	100.00%	0.00%	$385,563	$0.0
Fossil	$2,984,157	60.5%	39.5%	$1,806,344	$1,177,814
Combustion Turbine	$180,216	0.00%	100.00%	$0.0	$180,216
Nuclear	$20,946,119	81.0%	19.0%	$16,960,280	$3,985,839
Combined Cycle	$1,111,025	34.1%	65.9%	$378,896	$733,128
Hydro	$177,356	83.0%	17.0%	$147,283	$30,072
Wind	$4,706,297	93.3%	6.7%	$4,390,078	$316,219
Total Generation-Related Other Production O&M	$30,491,732	**78.93%**	**21.07%**	$24,068,444	$6,423,28
Corporate Other Production O&M not Assigned to Generation Type	$1,084,782	**78.93%**	**21.07%**	$856,265	$228,517
Regional Market Expense (FERC Codes 575.1 – 575.8)	$685,188	**78.93%**	**21.07%**	$540,848	$144,339
Total Other Production O&M	$32,201,701	**78.93%**	**21.07%**	$25,465,557	$6,796,144

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

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

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 9 below.

Table 9

Excess Footage Charges (Per Foot)

Type	Present	Proposed
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 7.

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 Sheet No. 24 of the General Rules and Regulations. The Company is proposing to an increase in each as shown in Table 10 below.

Table 10

Winter Construction Charges

Type	Present	Proposed
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 7.

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 $3,017 as shown on page 1 of Exhibit___(MAP-1), Schedule 7. This increase in revenues is shown with the increase in late payment charges on lines 2 and 14 of Schedule 3 to my testimony. It is also shown on page 7, row 21 of Schedule 4 to my testimony. The proposed increase in these charges reduces the proposed increase in retail revenues by Mr. Paluck.

IV. CONCLUSION

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

A. Yes.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application of Northern States Power Company, a Minnesota Corporation For Authority to Increase Rates for Electric Service in North Dakota	))))	Case No. PU-20-441 OAH File No. 20200422

AFFIDAVIT OF
Michael A. Peppin

I, the undersigned, being duly sworn, depose and say that the foregoing is the Revised Direct Testimony of the undersigned, and that such Revised Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Michael A. Peppin
Michael A. Peppin

Subscribed and sworn to before me, this 22 day of March, 2021.

Steven D. Spiess
Notary Public
My Commission Expires: 1/31/2025

STEVEN DELMONT SPIESS
NOTARY PUBLIC
MINNESOTA
My Commission Expires Jan. 31, 2025

Highlighted values have been revised.

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

Highlighted values have been revised.

Xcel Energy®
RESPONSIBLE BY NATURE™

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

Highlighted values have been revised.

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 4 basic functions and the associated sub-functions are shown in the table below:

Highlighted values have been revised.

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.

Highlighted values have been revised.

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 percents 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 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 (MDS) 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 system method. The 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.

Highlighted values have been revised.

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 zero-intercept method compared to the minimum system method. As shown below, for 4 of the 6 property units the zero intercept provides a lower customer component, while 2 of the 6 have a lower customer component using the minimum system method.

	% of Costs Classified as "Customer" Related	
Equipment Type	**Zero Intercept Method**	**Minimum 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 zero intercept and minimum system results 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%

Highlighted values have been revised.

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 2 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
  - 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 3 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
        - Individual customer maximum demands
      - Energy-related allocators such as:
        - kWh at the customer (kWh sales)
        - kWh at the generator (kWh sales plus loses)
        - kWh energy, weighted by the variable cost of the energy in the hour it's used
      - Customer-related allocators
        - Number of customers
        - 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
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)

Highlighted values have been revised.

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.

Highlighted values have been revised.

XI. CCOSS Output

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

Final CCOSS Printout "Tot" Worksheet

CCOSS Section	Page Number	Results Detail	Line Numbers
Results Summary	1	Rate Base Summary	1-21
		Income Statement Summary	22-31
	2	**Proposed Cost** Responsibility at <u>Equal ROR</u> (the cost of service) compared to **Present** Rate **Revenue** Responsibility	1-49
	3	**Proposed Cost** Responsibility at <u>Equal ROR</u> (the cost of service) compared to **Proposed** Rate **Revenue** Responsibility	1-52
Rate Base Detail	4	Original Plant in Service	1-52
	5	MINUS Accumulated Depreciation	1-29
		MINUS Accumulated Deferred Income Tax	30-57
	6	PLUS Construction Work in Progress & Other Additions	1-36
		EQUALS Total Rate Base & Common Rate Base	37-38
Income Statement Detail	7	Present and Proposed Revenues	1-26
		MINUS O&M Expenses part 1	27-41
	8	MINUS O&M Expenses part 2	1-34
	9	MINUS Book Depreciation	1-24
		MINUS Real Estate & Property Taxes, Other Taxes	25-51
	10	MINUS Provision for Deferred Income Tax	1-27
		MINUS Investment Tax Credit; Total Operating Expense	28-52
		EQUALS Present and Proposed Operating Income Before Income Taxes	53A 53B
	11 (Income Tax Calcs.)	Tax Additions	31-36
		MINUS Tax Deductions	1-30
		EQUALS Total Income Tax Adjustments	37
		Present and Proposed Taxable Net Income	38A 38B
		Present and Proposed State and Federal Income Taxes	39A 39B
		Present and Proposed Preliminary Return	40A 40B
		AFUDC (from page 12)	41
		Present and Proposed Total Return	42A 42B
Misc Calcs	12	AFUDC	1-25
		Labor Allocator	26-47
Allocator Data	13	Internal Allocators and Associated Data	1-31
	14	External Allocators and Associated Data	1-48

Northern States Power Company

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

Highlighted values have been revised.

	Customer Class	Rate Codes	kW Size	Voltage Specifications	Costs Not Assigned	Why Costs Not Assigned
1	Residential	D01, D02, D03, D04, D05 (if residential), D10 (if residential)			• 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	D05 (if C&I), D10 (if C&I), D12, D14, D15, D18, D19, D34, D40, D42	< 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 use to provide service to these customers.
3	C&I Secondary Voltage	D16, D17, D20, D21, D22, D41	> 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	D16, D17, D20, D21, D22, D41	> 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	D16, D17, D20, D21, D22, D41	> 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	D16, D17, D20, D21, D22, D41	> 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	D11, D30, D31, D32, D33			• 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

Highlighted values have been revised.

The table below lists and describes the external allocators used in the Class Cost of Service (CCOSS) model.

Code	Allocator for:	Description	Allocator Rationale & Background
C11	Connection charge revenues	Average monthly customers for the Test Year	Customer connection revenues are driven by number of customer services.
C10	Used to calculate C11	C11 less automatic protective lighting and load management services. C11 less number of customers with a second service.	
C11WAF	Used to calculate C11WA allocator	Customer accounting cost weighting factors. The weighting factor for residential customers is set at 1.0. The weighting factors for other classes are defined relative to costs for residential. E.g., if a class were three times costlier, its factor would be 3.0.	Weighting factors are set so as to reflect the relative costs of meter reading, billing and providing customer service for different classes of customers. For example some rate schedules are significantly more complex requiring more sophisticated meter reading capabilities, billing systems and customer service staff.
C11WA	Customer accounting costs	Average monthly customers weighted by each class' relative rating of customer accounting costs: C11 X C11WAF	<u>Customer accounting</u> costs are driven by number of customers and the complexity of their respective rate, billing issues and customer service requirements.
C12	Used to calculate C12WM allocator	Reflects actual number of meters. C11 with an adjusted street lighting customer count. Only selected street lighting rates are metered	
C12WMF	Used to calculate C12WM allocator	Average meter cost for each customer type	
C12WM	Meter costs	Number of meters multiplied by each class' average meter costs: C12 X C12WMF	<u>Metering</u> costs are driven by the number of customers in each class and the respective metering costs.
C61PS	The "customer" (minimum system) portion of <u>primary</u> distribution line costs	Average monthly customers served at primary or secondary voltage. C11 less transmission transformed and transmission voltage customers	The number of customers served at secondary and primary voltages drives the customer related portion of <u>primary distribution line</u> costs. Transmission and Transmission Transformed voltage customers are excluded since they do not use the distribution system.

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

Highlighted values have been revised.

Code	Allocator for:	Derivation	Allocator Rationale & Background
C62Sec	The "customer" (minimum system) portion of secondary (not primary) distribution line costs	Average monthly customers served at secondary voltage. C61PS less primary voltage customers	The number of customers served at secondary voltage drives the customer related portion of secondary distribution line costs. Transmission and primary voltage customers are excluded since they do not use the secondary distribution system.
C62NL	The "customer" (minimum system) portion of service-line costs.	Adjusted average monthly secondary voltage customers. C62Sec less street lighting and C&I underground customers	The number of secondary customers drives the customer portion of service line costs. C&I underground secondary customers are excluded since they own their services. Lighting customers are excluded since they do not have services.
D60Sub	Distribution substation costs	Class Coincident peak measured at the high voltage side of the Distribution Substation less Class Coincident peak of Transmission Voltage customers	Distribution substation costs are driven by class peak demands, whenever they occur which is generally at times other than the total system peak. Transmission voltage customers are excluded since they do not use the distribution substation.
D61PS	The capacity portion of primary distribution line costs.	D60Sub less Transmission Transformed customer demands, less customer demands served by minimum distribution system and with reduced Residential Space Heating demands to reflect the fact that their summer peak is less than their winter peak.	The driver of primary distribution line costs is the class coincident demands less the minimum system demand of each class. The minimum demand is classified as a customer related cost. Also, transmission and transmission transformed voltage customers are excluded since they do not use the distribution system.
D62Sec	Used to calculate the D62SecL allocator	D61PS less class coincident demands of primary voltage customers	
D62SecL	The capacity portion of secondary distribution line costs	D62SecL equals the average of D62Sec percent and non-coincident (or "individual customer peak") secondary voltage percent.	Capacity related secondary distribution line costs are driven by both class coincident peak demand and individual customer maximum demand, less the minimum system demand of each class. (The minimum system demand is classified as customer related.) Also, transmission and primary voltage customers are excluded since they do not use the secondary distribution system.

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

Highlighted values have been revised.

Code	Allocator For:	Derivation	Allocator Rationale
D62NLL	The capacity portion of service-line costs	Non-coincident (or "customer peak") demand for secondary voltage customers, less the customer peak demand for street lighting, area lighting and C&I customers served underground	Capacity related service line costs are driven by individual customer maximum demands less the minimum system demand of each class. (The minimum system demand is customer related.) Transmission voltage, primary voltage and lighting customers are excluded since they do not cause service-related costs. Also excluded are C&I underground customers since they install their own services.
D10S	Summer season portion of capacity-related generation costs	Each class' % contribution to the single summer system peak. Summer months are June through September.	The class contribution to the system summer peak drives the summer portion of capacity-related generation costs.
D10W	Winter season portion of capacity-related generation costs	Each class' % contribution to the single winter system peak. Winter months are October through May.	The class contribution to the system winter peak drives the winter portion of capacity-related generation costs.
D10T	Transmission plant costs.	Weighted Class Contributions to Summer and Winter Peak loads. Allocator equals (D10W% plus (D10S% times 1.4257)) divided by (1 + 1.4257). The 1.4257 ratio is the ratio of the average summer and winter seasonal system peaks.	The driver for transmission costs is class contribution to the summer & winter system peaks. To reflect the fact that summer peaks have more impact, the summer peak contribution for each class is weighted by the ratio of average monthly summer and average monthly winter system peaks.
D10C	Capacity-related generation costs.	Weighted of Class Contributions to Summer and Winter system peak loads. Allocator equals (D10W% plus (D10S% times 3.4858) divided by (1 + 3.4858). The 3.4858 ratio is obtained from the average summer and winter season peak loads, after subtracting the average annual load from each monthly load.	Capacity- related generation costs are driven by class contribution to summer & winter system peaks. To reflect the fact that summer peaks have a disproportionate impact on capacity-related generation costs, the summer peak is weighted by the ratio of average monthly summer and winter system peaks, which are in excess of average annual demand.

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

Highlighted values have been revised.

Code	**Allocator For:**	**Derivation**	**Allocator Rationale**
E8760	Energy-related portion of generation, nuclear fuel capital and generation step-up costs. Also allocator for fuel, purchased energy and energy-related fixed generation costs.	Class hourly energy (MWH) requirements multiplied by the corresponding hourly marginal energy cost.	The driver of these costs is energy requirements, which is measured by hourly energy requirements weighted by hourly marginal energy costs.

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

Highlighted values have been revised.

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.

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 47 less A&G Labor on Page 12 line 45. A&G Labor is excluded to avoid a circular reference.	The specified expenses are directly related to Labor costs.
NEPIS	Property Insurance	Electric plant in service less accumulated provision for depreciation	Property insurance is 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.
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.

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

Highlighted values have been revised.

Code	Allocator for:	Description	Allocator Justification
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.
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 40 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

Highlighted values have been revised.

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 48 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 expenses	Present revenues for the test year	Economic Development expenses are used to retain or enhance the Company's revenues.
RTBASE	Income Tax Addition: Avoided tax interest	Total Rate Base (line 37 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 D10C 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. (Line 42 on page 12, less lines 32 and 39)	Distribution labor (excluding Supervision & Engineering) drives Supervision and Engineering and Customer Installation Labor.

Guide to the Class Cost of Service Study
CCOSS RELATED ANALYSIS

Highlighted values have been revised.

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 Test Year. 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 (2024-2018). The resulting load shapes for each class are synced up to the 2020 forecast for the 2021, Test Year. 2. Hourly system marginal energy costs are based on the 2021 Test Year forecast 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 2017 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 actuals with the relative weighting estimates provided by management from the Billing and Customer Service areas.

Guide to the Class Cost of Service Study
CCOSS RELATED ANALYSIS

Highlighted values have been revised.

Analysis	**Analysis Description**	**Data Sources and Associated Vintage**
Minimum System 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. In 2015 and 2019 the Company conducted a Minimum System study that was updated to 2021 using the Handy Whitman Indices. 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.	Based on an analysis of nearly 12,000 distribution construction work orders in Minnesota Company that were completed from 2007 to May of 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 2020.
Classification of Other Production O&M Costs	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 budget detail of Other Production O&M expenses and 2020 Plant Stratification Analysis.

Guide to the Class Cost of Service Study
CCOSS RELATED ANALYSIS

Highlighted values have been revised.

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 only.	• TY2021 plant investment in FERC code 364 (overhead distribution poles). • The total number of overhead distribution poles based on 2016 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 distribution system.	2020 listing from the GIS system of all customer premises in MN and whether they receive service off the 3 phase or 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.	2020 listing from the GIS system of all customer premises in MNCO and whether they are served from an overhead or underground transformer.

Northern States Power Company
North Dakota
Summary of 2021 Proposed Class Cost of Service Study ($000)
Includes Fuel Correction

Highlighted values have been revised.

UNADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	225,570	90,717	11,587	120,411	2,854
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	44	38	1	4	0
[3]	Unadjusted Operating Revenues (line 1 + line 2)	225,613	90,756	11,589	120,415	2,854
[4]	Present Rates (CCOSS page 2, line 2)	206,416	83,739	11,379	109,232	2,066
[5]	Unadjusted Deficiency (line 3 - line 4)	19,197	7,016	209	11,183	788
[6]	Defic / Pres (line 5 / line 4)	9.3%	8.4%	1.8%	10.2%	38.2%
[7]	**Ratio: Class % / Total %**	**1.00**	**0.90**	**0.20**	**1.10**	**4.10**

COST RESPONSIBILITIES FOR RATE DISCOUNTS

		Total	Residential	Non-Demand	Demand	Street Ltg
[8]	Interruptible Rate Discounts (CCOSS page 2, line 5)	4,207	799	58	3,350	0
[9]	Interruptible Rate Disc Cost Allocation (CCOSS page 2, line 7)	4,207	1,415	188	2,591	13
[10]	Revenue Requirement Change (lines 10 & 11 - lines 8 & 9)	0	616	130	(759)	13

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[11]	Adjusted Rate Revenue Reqt (line 1 + line 10)	225,570	91,334	11,717	119,652	2,867
[12]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	44	38	1	4	0
[13]	Adjusted Operating Revenues (line 11 + line 12)	225,613	91,372	11,718	119,656	2,867
[14]	Present Rates (line 4)	206,416	83,739	11,379	109,232	2,066
[15]	Adjusted Deficiency (line 13 - line 14)	19,197	7,633	339	10,424	801
[16]	Defic / Pres Rates (line 15 / line 14)	9.3%	9.1%	3.0%	9.5%	38.8%
[17]	**Ratio: Class % / Total %**	**1.00**	**0.98**	**0.32**	**1.03**	**4.17**

PROPOSED REVENUE RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[18]	Proposed Rates (CCOSS page 3, line 3)	225,570	91,526	11,742	119,904	2,399
[19]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	44	38	1	4	0
[20]	Proposed Operating Revenues (line 18 + line 19)	225,614	91,564	11,743	119,907	2,399
[21]	Proposed Increase (line 20 - line 14)	19,197	7,825	363	10,676	333
[22]	Difference / Pres (line 21 / line 14)	9.3%	9.3%	3.2%	9.8%	16.1%
[23]	**Ratio: Class % / Total %**	**1.00**	**1.00**	**0.34**	**1.05**	**1.73**

North Dakota 2021 Proposed CCOSS ($000) - Includes Fuel Correction

Highlighted values have been revised.

Rate Base

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Plant In Service	**Alloc**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Production		885,937	321,037	559,704	42,845	516,859	450,525	66,334	0	0	5,196
2	Transmission		240,321	85,570	153,377	11,321	142,056	120,687	21,369	0	0	1,374
3	Distribution		213,025	135,528	70,979	12,801	58,178	49,876	8,302	0	0	6,518
4	General		132,512	53,640	77,577	6,626	70,951	61,452	9,499	0	0	1,295
5	Common		0	0	0	0	0	0	0	0	0	0
6	Total Plant In Service		1,471,794	595,774	861,637	73,593	788,043	682,539	105,504	0	0	14,383
7	Production		471,529	171,031	297,716	22,827	274,889	239,736	35,153	0	0	2,783
8	Transmission		60,624	21,577	38,701	2,855	35,846	30,449	5,397	0	0	346
9	Distribution		80,327	53,700	23,865	4,759	19,107	16,410	2,697	0	0	2,762
10	General		65,361	26,458	38,264	3,268	34,996	30,311	4,685	0	0	639
11	Common		0	0	0	0	0	0	0	0	0	0
12	Total Depreciation Reserve		677,840	272,765	398,546	33,709	364,838	316,905	47,932	0	0	6,529
13	**Net Plant In Service**		793,954	323,009	463,090	39,885	423,206	365,634	57,572	0	0	7,854
14	Deducts: Accum Defer Inc Tax		147,086	59,774	85,859	7,323	78,535	67,668	10,867	0	0	1,453
15	Constr Work In Progress		1,914	727	1,173	94	1,079	939	140	0	0	14
16	Fuel Inventory		6,579	2,428	4,107	325	3,783	3,332	451	0	0	43
17	Materials & Supplies		10,807	4,059	6,671	528	6,142	5,344	798	0	0	77
18	Prepayments		9,435	3,838	5,503	474	5,029	4,345	684	0	0	93
19	Non-Plant & Work Cash		1,315	531	680	90	590	530	59	0	0	103
20	Total Additions		30,049	11,584	18,134	1,511	16,623	14,490	2,133	0	0	331
21	**Rate Base**		676,917	274,819	395,366	34,072	361,293	312,456	48,838	0	0	6,732

Income Statement

			ND	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
22A	**Tot Oper Rev - Pres**		245,977	98,515	145,144	13,294	131,850	118,082	13,768	0	0	2,318
22B	**Tot Oper Rev - Prop**		265,174	106,340	156,183	13,657	142,526	127,715	14,811	0	0	2,651
23	Oper & Maint		153,060	60,009	91,100	7,896	83,204	72,317	10,887	0	0	1,951
24	Book Depr + IRS Int		54,544	22,211	31,769	2,714	29,055	25,184	3,871	0	0	564
25	Payroll, Rl Est & Prop Tax		13,527	5,453	7,921	679	7,242	6,252	990	0	0	152
26	Deferred Inc Tax & Net ITC		(7,433)	(3,458)	(3,861)	(385)	(3,476)	(2,962)	(514)	0	0	(114)
27A	Present Income Tax		(2,962)	(595)	(2,232)	44	(2,276)	(1,122)	(1,155)	0	0	(134)
27B	Proposed Income Tax		1,723	1,314	462	133	329	1,229	(900)	0	0	(53)
28	Allow Funds Dur Const		0	0	0	0	0	0	0	0	0	0
29A	**Present Return**		35,241	14,895	20,447	2,346	18,101	18,413	(311)	0	0	(101)
29B	**Proposed Return**		49,754	20,811	28,792	2,621	26,172	25,695	477	0	0	151
30A	**Pres Ret on Rt Base**		5.21%	5.42%	5.17%	6.89%	5.01%	5.89%	-0.64%	0.00%	0.00%	-1.50%
30B	**Prop Ret on Rt Base**		**7.35%**	7.57%	7.28%	7.69%	7.24%	8.22%	0.98%	0.00%	0.00%	2.24%
31A	**Pres Ret on Common**		6.13%	6.53%	6.06%	9.32%	5.75%	7.43%	-5.01%	0.00%	0.00%	-6.66%
31B	**Prop Ret on Common**		**10.21%**	10.63%	10.08%	10.86%	10.01%	11.87%	-1.93%	0.00%	0.00%	0.47%

North Dakota 2021 Proposed CCOSS ($000) - Includes Fuel Correction

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**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**UnAdj Equal Rev Reqt @ 7.35%**		**225,569.792**	**90,717**	**131,998**	**11,587**	**120,411**	**104,481**	**15,930**	**0**	**0**	**2,854**
2	**Present Revenue**		**206,416**	**83,739**	**120,611**	**11,379**	**109,232**	**98,462**	**10,770**	**0**	**0**	**2,066**
3	**UnAdj Revenue Deficiency**		**19,154**	**6,978**	**11,387**	**208**	**11,179**	**6,019**	**5,160**	**0**	**0**	**788**
4	**UnAdj Deficiency / Present**		**9.28%**	**8.33%**	**9.44%**	**1.83%**	**10.23%**	**6.11%**	**47.92%**	**0.00%**	**0.00%**	**38.17%**
5	**Pres Int Rate Discounts**		**4,207**	**798.775**	**3,408**	**58**	**3,350**	**2,327**	**1,023**	**0**	**0**	**0**
6	**Pres Int Rate Disc Cost Alloc**	**D10C**	**4,207**	**1,415**	**2,778**	**188**	**2,591**	**2,173**	**418**	**0**	**0**	**13**
7	**Revenue Requirement Shift**		**0**	**616**	**(629)**	**130**	**(759)**	**(154)**	**(605)**	**0**	**0**	**13**
8	**Adj Equal Rev Reqt (Rows 1+7)**		**225,570**	**91,334**	**131,369**	**11,717**	**119,652**	**104,327**	**15,325**	**0**	**0**	**2,867**
9	**Adj Rev Defic vs Pres Rev (Row 2)**		**19,154**	**7,594**	**10,758**	**338**	**10,420**	**5,865**	**4,555**	**0**	**0**	**801**
10	**Adj Deficiency / Adj Present**		**9.28%**	**9.07%**	**8.92%**	**2.97%**	**9.54%**	**5.96%**	**42.30%**	**0.00%**	**0.00%**	**38.80%**
	Equal Customer Classification											
11	Min Sys & Service Drop		14,392	10,928	1,851	1,061	790	773	17	0	0	1,613
12	Energy Services		5,041	3,992	1,035	633	402	398	4	0	0	15
13	Total Customer **(Cusco)**		19,432	14,919	2,886	1,694	1,192	1,171	21	0	0	1,628
14	Ave Monthly Customers		96,144	81,342	12,764	8,657	4,107	4,076	31	0	0	2,038
15	Svc Drop Reqt	$ / Mo / Cust	$12.47	$11.20	$12.08	$10.21	$16.03	$15.80	$46.18	$0.00	$0.00	$65.95
16	Ener Svcs Reqt	$ / Mo / Cust	$4.37	$4.09	$6.75	$6.09	$8.16	$8.14	$10.91	$0.00	$0.00	$0.61
17	Total Reqt	$ / Mo / Cust	$16.84	$15.28	$18.84	$16.30	$24.18	$23.93	$57.09	$0.00	$0.00	$66.56
	Equal Energy Classification											
18	On Peak Rev Reqt		46,808	16,083	30,606	2,450	28,156	24,832	3,324	0	0	118
19	Off Peak Rev Reqt		49,711	19,445	29,746	2,316	27,430	24,127	3,303	0	0	519
20	Total Ener Rev Reqt		96,518	35,529	60,352	4,766	55,586	48,959	6,627	0	0	637
21	Annual MWh Sales		2,136,485	779,209	1,339,342	102,502	1,236,839	1,086,222	150,618	0	0	17,934
22	On Pk Reqt	Mills / kWh	21.909	20.641	22.852	23.901	22.765	22.861	22.068	0.000	0.000	6.593
23	Off Pk Reqt	Mills / kWh	23.267	24.955	22.210	22.596	22.178	22.212	21.930	0.000	0.000	28.941
24	Total Reqt	Mills / kWh	45.176	45.596	45.061	46.497	44.942	45.073	43.998	0.000	0.000	35.534
	Equal Demand Classification											
25	Energy-Related Prod		34,616	12,663	21,734	1,696	20,038	17,581	2,458	0	0	219
26	Capacity-Related Summer Peak Prod		23,255	7,802	15,381	1,039	14,342	12,030	2,313	0	0	72
27	Capacity-Related Winter Peak Prod		6,671	2,238	4,412	298	4,114	3,451	663	0	0	21
28	Total Capacity-Related Prod		29,926	10,040	19,793	1,336	18,457	15,481	2,976	0	0	93
29	Total Production		64,542	22,703	41,527	3,032	38,495	33,061	5,434	0	0	312
30	Transmission **(Transco)**		30,482	10,821	19,487	1,436	18,051	15,324	2,727	0	0	175
31	Primary Dist Subs		4,646	1,829	2,770	220	2,550	2,116	435	0	0	47
32	Prim Dist Lines		8,509	4,148	4,314	370	3,944	3,257	687	0	0	47
33	Second Dist, Trans		1,439	768	663	70	593	593	0	0	0	9
34	Total Distribution **(Disco)**		14,595	6,745	7,747	660	7,087	5,966	1,122	0	0	103
35	Total Demand Rev Reqt		109,619	40,269	68,760	5,128	63,633	54,351	9,282	0	0	589
36	Annual Billing kW		3,286,718	0	3,286,718	0	3,286,718	2,990,238	296,480	0	0	0
37	Base Rev Reqt	$ / kW	$0.00	$0.00	$6.61	$0.00	$6.10	$5.88	$8.29	$0.00	$0.00	$0.00
38	Summer Rev Reqt	$ / kW	$0.00	$0.00	$4.68	$0.00	$4.36	$4.02	$7.80	$0.00	$0.00	$0.00
39	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.34	$0.00	$1.25	$1.15	$2.24	$0.00	$0.00	$0.00
40	Prod Rev Reqt	$ / kW	$0.00	$0.00	$12.63	$0.00	$11.71	$11.06	$18.33	$0.00	$0.00	$0.00
41	Tran Rev Reqt	$ / kW	$0.00	$0.00	$5.93	$0.00	$5.49	$5.12	$9.20	$0.00	$0.00	$0.00
42	Dist Rev Reqt	$ / kW	$0.00	$0.00	$2.36	$0.00	$2.16	$1.99	$3.78	$0.00	$0.00	$0.00
43	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$20.92	$0.00	$19.36	$18.18	$31.31	$0.00	$0.00	$0.00
44	Tot Dmd Rev Reqt	Mills / kWh	51.308	51.680	51.339	50.026	51.448	50.037	61.625	0.000	0.000	32.852
45	Summer Billing kW		1,137,231	0	1,137,231	0	1,137,231	1,031,540	105,690	0	0	0
46	Winter Billing kW		2,149,487	0	2,149,487	0	2,149,487	1,958,698	190,789	0	0	0
47	Tot Summer Reqt	$ / kW	$0.00	$0.00	$28.42	$0.00	$26.36	$24.66	$43.15	$0.00	$0.00	$0.00
48	Tot Winter Reqt	$ / kW	$0.00	$0.00	$16.95	$0.00	$15.66	$14.76	$24.75	$0.00	$0.00	$0.00
49	Energy + Production **(Genco)**		161,060	58,232	101,880	7,798	94,081	82,021	12,061	0	0	949

Northern States Power Company

North Dakota 2021 Proposed CCOSS ($000) - Includes Fuel Correction

Highlighted values have been revised.

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	ND	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
1	**Proposed Ret On Rt Base**		7.35%	7.57%	7.28%	7.69%	7.24%	8.22%	0.98%	0.00%	0.00%	2.24%
2	**UnAdj Equalized Rev Reqt**		225,570	90,717	131,998	11,587	120,411	104,481	15,930	0	0	2,854
3	**Proposed Revenue**		225,570	91,526	131,645	11,742	119,904	108,091	11,812	0	0	2,399
4	**UnAdj Revenue Deficiency**		(0)	(809)	353	(154)	507	(3,611)	4,118	0	0	455
5	**UnAdj Deficiency / Proposed**		0.00%	-0.88%	0.27%	-1.31%	0.42%	-3.34%	34.86%	0%	0%	18.97%
6	**Prop Interrupt Rate Discounts**		3,619	41	3,577	61	3,517	2,445	1,071	0	0	0
7	**Prop Int Rate Disc Cost Alloc**	D10C	3,619	1,217	2,390	162	2,229	1,869	359	0	0	11
8	**Revenue Requirement Shift**		0	1,176	(1,187)	101	(1,288)	(576)	(712)	0	0	11
9	**Adj Equal Rev (Rows 2+8)**		225,570	91,893	130,811	11,688	119,123	103,905	15,218	0	0	2,865
10	**Adj Rev Defic vs Prop Rev (Row 3)**		(0)	367	(834)	(53)	(781)	(4,187)	3,406	0	0	466
11	**Adj Deficiency / Adj Prop**		0.00%	0.40%	-0.63%	-0.45%	-0.65%	-3.87%	28.83%	0.00%	0.00%	19.44%
	Prop Customer Component											
12	Min Sys & Service Drop		14,364	11,056	1,897	1,080	817	803	13	0	0	1,411
13	Energy Services		5,042	3,992	1,035	633	402	398	4	0	0	15
14	Total Customer **(Cusco)**		19,406	15,048	2,932	1,713	1,219	1,201	17	0	0	1,425
15	Ave Monthly Customers		96,144	81,342	12,764	8,657	4,107	4,076	31	0	0	2,038
16	Svc Drop Reqt	$ / Mo / Cust	$12.45	$11.33	$12.38	$10.40	$16.57	$16.42	$35.89	$0.00	$0.00	$57.68
17	Ener Svcs Reqt	$ / Mo / Cust	$4.37	$4.09	$6.76	$6.09	$8.16	$8.14	$10.87	$0.00	$0.00	$0.60
18	Total Reqt	$ / Mo / Cust	$16.82	$15.42	$19.14	$16.49	$24.73	$24.56	$46.76	$0.00	$0.00	$58.28
	Prop Energy Component											
19	On Peak Rev Reqt		46,814	16,088	30,608	2,451	28,157	24,862	3,295	0	0	117
20	Off Peak Rev Reqt		49,714	19,451	29,747	2,317	27,430	24,155	3,275	0	0	515
21	Total Ener Rev Reqt		96,528	35,539	60,355	4,768	55,587	49,017	6,570	0	0	633
22	Annual MWh Sales		2,136,485	779,209	1,339,342	102,502	1,236,839	1,086,222	150,618	0	0	17,934
23	On Pk Reqt	Mills / kWh	21.912	20.647	22.853	23.912	22.765	22.888	21.878	0.000	0.000	6.548
24	Off Pk Reqt	Mills / kWh	23.269	24.963	22.210	22.606	22.178	22.238	21.742	0.000	0.000	28.741
25	Total Reqt	Mills / kWh	45.181	45.610	45.063	46.518	44.943	45.126	43.620	0.000	0.000	35.289
	Prop Demand Component											
26	Energy-Related Prod		34,913	13,005	21,830	1,766	20,063	19,424	639	0	0	79
27	Capacity-Related Summer Peak Prod		23,159	7,868	15,233	1,052	14,181	12,430	1,751	0	0	58
28	Capacity-Related Winter Peak Prod		6,644	2,257	4,370	302	4,068	3,566	502	0	0	17
29	Total Capacity-Related Prod		29,803	10,125	19,603	1,354	18,249	15,996	2,253	0	0	75
30	Total Production		64,717	23,131	41,433	3,120	38,313	35,420	2,893	0	0	153
31	Transmission **(Transco)**		30,357	10,973	19,265	1,467	17,799	16,167	1,632	0	0	118
32	Primary Dist Subs		4,594	1,861	2,704	226	2,479	2,259	219	0	0	28
33	Prim Dist Lines		8,475	4,192	4,248	376	3,872	3,392	481	0	0	36
34	Second Dist, Trans		1,494	781	708	72	636	636	0	0	0	5
35	Total Distribution **(Disco)**		14,563	6,834	7,660	673	6,986	6,286	700	0	0	69
36	Total Demand Rev Reqt		109,637	40,938	68,358	5,260	63,098	57,873	5,225	0	0	341
37	Annual Billing kW		3,286,718	0	3,286,718	0	3,286,718	2,990,238	296,480	0	0	0
38	Base Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$6.10	$6.50	$2.16	$0.00	$0.00	$0.00
39	Summer Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$4.31	$4.16	$5.91	$0.00	$0.00	$0.00
40	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$1.24	$1.19	$1.69	$0.00	$0.00	$0.00
41	Prod Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$11.66	$11.85	$9.76	$0.00	$0.00	$0.00
42	Tran Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$5.42	$5.41	$5.51	$0.00	$0.00	$0.00
43	Dist Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$2.13	$2.10	$2.36	$0.00	$0.00	$0.00
44	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$19.20	$19.35	$17.62	$0.00	$0.00	$0.00
45	Tot Dmd Rev Reqt	Mills / kWh	51.316	52.538	51.039	51.318	51.015	53.279	34.690	0.000	0.000	18.998
46	Summer Billing kW		1,137,231	0	1,137,231	0	1,137,231	1,031,540	105,690	0	0	0
47	Winter Billing kW		2,149,487	0	2,149,487	0	2,149,487	1,958,698	190,789	0	0	0
48	Tot Summer Reqt	$ / kW	$0.00	$0.00	$28.23	$0.00	$26.12	$26.05	$26.59	$0.00	$0.00	$0.00
49	Tot Winter Reqt	$ / kW	$0.00	$0.00	$16.87	$0.00	$15.54	$15.83	$12.66	$0.00	$0.00	$0.00
50	Energy + Production **(Genco)**		161,244	58,670	101,788	7,888	93,900	84,437	9,462	0	0	786
51	Prop Rev - Pres Rev (Pg 2)		19,154	7,786	11,034	362	10,672	9,629	1,043	0	0	333
52	Difference / Present		9.28%	9.30%	9.15%	3.18%	9.77%	9.78%	9.68%	0.00%	0.00%	16.13%

North Dakota 2021 Proposed CCOSS ($000) - Includes Fuel Correction

Highlighted values have been revised.

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**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Summer Peak	D10C		141,981	47,767	93,775	6,337	87,438	73,343	14,095	0	0	439
2	WInter Peak	D10C		40,731	13,703	26,902	1,818	25,084	21,040	4,043	0	0	126
3	Total Peak	D10C		182,712	61,470	120,677	8,155	112,522	94,383	18,138	0	0	566
4	Base Load	E8760		523,519	193,236	326,836	25,825	301,011	265,131	35,880	0	0	3,447
5	Nuclear Fuel	E8760		179,706	66,331	112,191	8,865	103,326	91,010	12,316	0	0	1,183
6	Total	25.87%	120, 310-346	885,937	321,037	559,704	42,845	516,859	450,525	66,334	0	0	5,196
	Transmission												
7	Gen Step Up Base	E8760		6,389	2,358	3,989	315	3,674	3,236	438	0	0	42
8	Gen Step Up Peak	D10C		2,412	811	1,593	108	1,485	1,246	239	0	0	7
9	Total Gen Step Up			8,801	3,170	5,582	423	5,159	4,482	677	0	0	50
10	Bulk Transmission	D10T		231,458	82,400	147,734	10,898	136,835	116,205	20,630	0	0	1,325
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		61	0	61	0	61	0	61	0	0	0
13	Total		350-359	240,321	85,570	153,377	11,321	142,056	120,687	21,369	0	0	1,374
	Distribution:												
	Substations												
14	Generat Step Up	STRATH		216	79	136	10	126	110	16	0	0	1
15	Bulk Transmission	D10T		121	43	77	6	71	61	11	0	0	1
16	Distrib Function	D60Sub		38,649	15,252	23,007	1,828	21,180	17,571	3,609	0	0	390
17	Direct Assign	Dir Assign		0.000	0	0	0	0	0	0	0	0	0
18	Total		360-363	38,986	15,374	23,221	1,844	21,377	17,742	3,635	0	0	392
	Overhead Lines												
19	Primary Capacity 1 Phase	D61PS1Ph		6,792	4,907	1,885	317	1,568	1,283	285	0	0	0
20	Primary Capacity Multi Phase	D61PS		14,613	5,288	9,201	608	8,593	7,110	1,483	0	0	125
21	Primary Customer 1 Phase	C61PS1Ph		3,644	3,407	236	203	34	33	0	0	0	0
22	Primary Customer Multi Phase	C61PS		7,839	6,760	1,059	716	343	340	3	0	0	20
23	Total Primary			32,888	20,362	12,381	1,843	10,538	8,767	1,770	0	0	145
24	Second Capacity	D62SecL		1,671	864	797	83	714	714	0	0	0	11
25	Second Customer	C62Sec		6,014	5,188	810	549	261	261	0	0	0	16
26	Total Secondary			7,685	6,051	1,608	633	975	975	0	0	0	26
27	Street Lighting	DASL		2,411	0	0	0	0	0	0	0	0	2,411
28	Total		364,365	42,984	26,413	13,989	2,476	11,513	9,743	1,770	0	0	2,582
	Underground Lines												
29	Primary Capacity 1 Phase	D61PS1Ph		13,408	9,687	3,721	626	3,095	2,533	562	0	0	0
30	Primary Capacity Multi Phase	D61PS		19,271	6,973	12,134	802	11,332	9,377	1,955	0	0	164
31	Primary Customer 1 Phase	C61PS1Ph		15,238	14,249	989	848	141	140	1	0	0	0
32	Primary Customer Multi Phase	C61PS		21,900	18,886	2,958	2,000	958	951	7	0	0	57
33	Total Primary			69,818	49,795	19,802	4,275	15,526	13,001	2,526	0	0	221
34	Second Capacity	D62SecL		2,246	1,160	1,071	112	959	959	0	0	0	14
35	Second Customer	C62Sec		6,314	5,447	851	577	274	274	0	0	0	16
36	Total Secondary			8,560	6,607	1,922	689	1,233	1,233	0	0	0	31
37	Street Lighting	DASL		0	0	0	0	0	0	0	0	0	0
38	Total		366,367	78,378	56,402	21,724	4,964	16,760	14,234	2,526	0	0	252
	Line Transformers												
39	Primary	D61PS		2,988	1,081	1,881	124	1,757	1,454	303	0	0	25
40	Second Capacity	D62SecL		8,920	4,608	4,255	445	3,809	3,809	0	0	0	57
41	Second Customer	C62Sec		15,665	13,513	2,111	1,431	681	681	0	0	0	41
42	Total		368	27,573	19,203	8,247	2,000	6,247	5,944	303	0	0	123
	Services												
43	Second Capacity	D62NLL		862	682	180	26	154	154	0	0	0	0
44	Second Customer	C62NL		14,364	13,413	952	645	307	307	0	0	0	0
45	Total Services	C62NL	369	15,226	14,095	1,132	671	460	460	0	0	0	0
46	Meters	C12WM	370	6,715	4,042	2,667	845	1,821	1,753	68	0	0	7
47	Street Lighting	Dir Assign	373	3,163	0	0	0	0	0	0	0	0	3,163
48	**Total Distribution**			213,025	135,528	70,979	12,801	58,178	49,876	8,302	0	0	6,518
49	**General & Common Plant**	PTD	303, 389-399	132,512	53,640	77,577	6,626	70,951	61,452	9,499	0	0	1,295
50	Prelim Elec Plant			1,471,794	595,774	861,637	73,593	788,043	682,539	105,504	0	0	14,383
51	TBT Investment	NEPIS		0	0	0	0	0	0	0	0	0	0
52	**Elec Plant in Serv**			1,471,794	595,774	861,637	73,593	788,043	682,539	105,504	0	0	14,383

North Dakota 2021 Proposed CCOSS ($000) - Includes Fuel Correction

Highlighted values have been revised.

	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**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10C		92,277	31,045	60,947	4,119	56,828	47,668	9,161	0	0	286
2	Decom Int Peaking	D10C		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		167,645	61,879	104,661	8,270	96,392	84,902	11,490	0	0	1,104
5	Base Load	E8760		211,607	78,106	132,108	10,439	121,669	107,167	14,503	0	0	1,393
6	Total		108,111,115,120.5	471,529	171,031	297,716	22,827	274,889	239,736	35,153	0	0	2,783
	Transmission												
7	Gen Step Up Base	E8760		1,478	546	923	73	850	749	101	0	0	10
8	Gen Step Up Peak	D10C		953	321	629	43	587	492	95	0	0	3
9	Total Gen Step Up			2,431	866	1,552	115	1,437	1,241	196	0	0	13
10	Bulk Transmission	D10T		58,176	20,711	37,132	2,739	34,393	29,208	5,185	0	0	333
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		16	0	16	0	16	0	16	0	0	0
13	Total		108,111,115,120.5	60,624	21,577	38,701	2,855	35,846	30,449	5,397	0	0	346
	Distribution												
14	Generat Step Up	STRATH		160	58	101	8	93	81	12	0	0	1
15	Bulk Transmission	D10T		44	16	28	2	26	22	4	0	0	0
16	Distrib Function	D60Sub		8,510	3,358	5,066	402	4,664	3,869	795	0	0	86
17	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
18	Total Substations			8,714	3,432	5,195	412	4,783	3,972	810	0	0	87
19	Overhead Lines	POL		20,918	12,854	6,808	1,205	5,603	4,741	861	0	0	1,256
20	Underground	PUL		28,689	20,645	7,952	1,817	6,135	5,210	924	0	0	92
21	Line Transformers	P68		6,663	4,641	1,993	483	1,510	1,436	73	0	0	30
22	Services	P69		11,342	10,499	843	500	343	343	0	0	0	0
23	Meters	C12WM		2,707	1,629	1,075	341	734	707	27	0	0	3
24	Street Lighting	P73		1,294	0	0	0	0	0	0	0	0	1,294
25	Total		108,111,115,120.5	80,327	53,700	23,865	4,759	19,107	16,410	2,697	0	0	2,762
26	**General & CommonPlant**	PTD	108,111,115,120.5	65,361	26,458	38,264	3,268	34,996	30,311	4,685	0	0	639
27	**Total Accum Depr**			677,840	272,765	398,546	33,709	364,838	316,905	47,932	0	0	6,529
28	**Net Elec Plant**			793,954	323,009	463,090	39,885	423,206	365,634	57,572	0	0	7,854
29	**Net Plant w/ TBT**			793,954	323,009	463,090	39,885	423,206	365,634	57,572	0	0	7,854
	Subtractions: Accum Defer Inc Tax												
	Production												
30	Peaking Plant	D10C		21,296	7,164	14,065	950	13,115	11,001	2,114	0	0	66
31	Base Load	E8760		70,806	26,135	44,204	3,493	40,712	35,859	4,853	0	0	466
32	Nuclear Fuel	E8760		(332)	(123)	(207)	(16)	(191)	(168)	(23)	0	0	(2)
33	Total		190,281,282,283	91,769	33,177	58,062	4,427	53,635	46,691	6,944	0	0	530
	Transmission												
34	Gen Step Up Base	D10C		794	267	525	35	489	410	79	0	0	2
35	Gen Step Up Peak	D10C		299	101	198	13	184	155	30	0	0	1
36	Total Gen Step Up			1,094	368	722	49	674	565	109	0	0	3
37	Bulk Transmission	D10T		48,147	17,140	30,731	2,267	28,464	24,172	4,291	0	0	276
38	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
39	Direct Assign	Dir Assign		13	0	13	0	13	0	13	0	0	0
40	Total		281,282,283	49,253	17,508	31,466	2,316	29,150	24,737	4,413	0	0	279
	Distribution												
41	Generat Step Up	STRATH		23	8	15	1	13	12	2	0	0	0
42	Bulk Transmission	D10T		18	6	11	1	11	9	2	0	0	0
43	Distrib Function	D60Sub		6,385	2,520	3,801	302	3,499	2,903	596	0	0	64
44	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
45	Total Substations			6,426	2,535	3,827	304	3,523	2,924	599	0	0	65
46	Overhead Lines	POL		5,871	3,608	1,911	338	1,572	1,331	242	0	0	353
47	Underground	PUL		12,205	8,783	3,383	773	2,610	2,217	393	0	0	39
48	Line Transformers	P68		2,773	1,931	829	201	628	598	30	0	0	12
49	Services	P69		1,743	1,613	130	77	53	53	0	0	0	0
50	Meters	C12WM		743	447	295	94	202	194	8	0	0	1
51	Street Lighting	P73		388	0	0	0	0	0	0	0	0	388
52	Total		281,282,283	30,149	18,917	10,375	1,787	8,588	7,315	1,272	0	0	857
53	**General & Common Plant**	PTD	281,282,283	9,959	4,031	5,830	498	5,332	4,618	714	0	0	97
54	**Total Deferred Tax**			181,130	73,633	105,733	9,027	96,706	83,362	13,343	0	0	1,763
55	Net Operating Loss (NOL) Carry F	NEPIS		(36,556)	(14,872)	(21,322)	(1,836)	(19,486)	(16,835)	(2,651)	0	0	(362)
56	Non-Plant Related	LABOR		2,512	1,013	1,448	132	1,315	1,141	174	0	0	51
57	**Accum Def W/ Adj**			147,086	59,774	85,859	7,323	78,535	67,668	10,867	0	0	1,453

North Dakota 2021 Proposed CCOSS ($000) - Includes Fuel Correction

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**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10C		127	43	84	6	78	66	13	0	0	0
2	Base Load	E8760		784	290	490	39	451	397	54	0	0	5
3	Nuclear Fuel	E8760		343	127	214	17	197	174	24	0	0	2
4	Total		107	1,255	459	788	61	727	637	90	0	0	8
	Transmission												
5	Gen Step Up Base	E8760		3	1	2	0	2	1	0	0	0	0
6	Gen Step Up Peak	D10C		10	3	7	0	6	5	1	0	0	0
7	Total Gen Step Up			13	4	8	1	8	7	1	0	0	0
8	Bulk Transmission	D10T		159	57	102	7	94	80	14	0	0	1
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	172	61	110	8	102	87	15	0	0	1
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10T		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		39	16	23	2	22	18	4	0	0	0
15	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
16	Total Substations			39	16	23	2	22	18	4	0	0	0
17	Overhead Lines	POL		15	9	5	1	4	3	1	0	0	1
18	Underground	PUL		22	16	6	1	5	4	1	0	0	0
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		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	76	40	34	4	30	25	5	0	0	1
24	**General & Common Plant**	PTD	107	411	166	241	21	220	191	29	0	0	4
25	**Total CWIP**			1,914	727	1,173	94	1,079	939	140	0	0	14
26	Fuel Inventory	E8760	151,152	6,579	2,428	4,107	325	3,783	3,332	451	0	0	43
	Materials & Supplies												
27	Production	P10		9,662	3,501	6,104	467	5,637	4,914	723	0	0	57
28	Trans & Distr	TD		1,144	558	566	61	505	431	75	0	0	20
29	Total		154	10,807	4,059	6,671	528	6,142	5,344	798	0	0	77
	Prepayments												
30	Miscellaneous	NEPIS		9,435	3,838	5,503	474	5,029	4,345	684	0	0	93
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	9,435	3,838	5,503	474	5,029	4,345	684	0	0	93
34	Non-Plant Assets & Liab	LABOR	190,283,	8,415	3,394	4,850	444	4,406	3,822	584	0	0	172
35	Working Cash	PT0	calculated	(7,100)	(2,862)	(4,169)	(353)	(3,816)	(3,292)	(524)	0	0	(68)
36	**Total Additions**			30,049	11,584	18,134	1,511	16,623	14,490	2,133	0	0	331
37	**Total Rate Base**			676,917	274,819	395,366	34,072	361,293	312,456	48,838	0	0	6,732
38	**Common Rate Base (@ 52.50%)**			355,381.3	144,280	207,567	17,888	189,679	164,039	25,640	0	0	3,534

Northern States Power Company

North Dakota 2021 Proposed CCOSS ($000) - Includes Fuel Correction

Highlighted values have been revised.

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**	**ND**	**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	206,416	83,739	120,611	11,379	109,232	98,462	10,770	0	0	2,066
2	Proposed Rate Revenue	PROREV; (calc)		225,570	91,526	131,645	11,742	119,904	108,091	11,812	0	0	2,399
3	Equal Rate Revenue			225,570	90,717	131,998	11,587	120,411	104,481	15,930	0	0	2,854
	Other Retail Revenue												
4	Interdepartmental	R01; R02	448	0	0	0	0	0	0	0	0	0	0
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**			0	0	0	0	0	0	0	0	0	0
	Other Operating Revenue												
8	Interchg Prod Capacity	P10	456	30,134	10,920	19,037	1,457	17,580	15,324	2,256	0	0	177
9	Interchg Prod Energy	E8760	456	0	0	0	0	0	0	0	0	0	0
10	Interchg Tr Bulk Supply	D10T	456	0	0	0	0	0	0	0	0	0	0
11	Dist Int Sales; Oth Serv	E8760	412,451,456	0	0	0	0	0	0	0	0	0	0
12	Dist Overhd Line Rent	POL	454	334	205	109	19	90	76	14	0	0	20
13	Connection Charges	C11	451	365	309	48	33	16	15	0	0	0	8
14	Sales For Resale	E8760	447	522	193	326	26	300	264	36	0	0	3
15	Joint Op Agree-Other PSCo Rev	D10T	456	0	0	0	0	0	0	0	0	0	0
16	Misc Ancillary Trans Rev	D10T		15,512	5,522	9,901	730	9,171	7,788	1,383	0	0	89
17	MISO	D10T	456	(7,327)	(2,609)	(4,677)	(345)	(4,332)	(3,679)	(653)	0	0	(42)
18	Other	D10T	451,456,457	(416)	(148)	(265)	(20)	(246)	(209)	(37)	0	0	(2)
19	Late Pay Chg - Pres	R16C; R02		436	383	53	13	40	40	0	0	0	0
20	**Tot Other Op - Pres**		450	39,560	14,775	24,533	1,914	22,618	19,620	2,999	0	0	252
21	Incr Misc Serv - Prop	C62NL		3	3	0	0	0	0	0	0	0	0
22	Incr Inter-Dept'l - Prop	R01; R02		0	0	0	0	0	0	0	0	0	0
23	Incr Late Pay - Prop	(R16C); R02		40	36	5	1	4	4	0	0	0	0
	Tot Incr Other Op			44	38	5	1	4	4	0	0	0	0
24	**Tot Other Op - Prop**			39,604	14,814	24,538	1,916	22,622	19,624	2,999	0	0	252
25	**Tot Oper Rev - Pres**			245,977	98,515	145,144	13,294	131,850	118,082	13,768	0	0	2,318
26	**Tot Oper Rev - Prop**			265,174	106,340	156,183	13,657	142,526	127,715	14,811	0	0	2,651
	Tot Oper Rev - Eql			265,174	105,531	156,536	13,503	143,033	124,105	18,929	0	0	3,107
	Operating & Maint (Pg 1 of 2)												
	Production Expen												
27	**Fuel**	E8760	501,518,547	32,925	12,153	20,555	1,624	18,931	16,675	2,257	0	0	217
	Purchased Power												
28	Purchases: Cap Peak	D10C		7,163	2,410	4,731	320	4,411	3,700	711	0	0	22
29	Purchases: Cap Base	D10C		2,665	897	1,760	119	1,641	1,377	265	0	0	8
30	Purchases: Demand		555	9,828	3,306	6,491	439	6,052	5,077	976	0	0	30
31	Purchases: Other Energy	E8760	555	20,426	7,539	12,752	1,008	11,744	10,344	1,400	0	0	134
32	Tot Non-Assoc Purch			30,254	10,846	19,243	1,446	17,797	15,421	2,376	0	0	165
33	Interchg Agr Capacity	P10WoN	557	3,043	1,097	1,928	146	1,782	1,549	233	0	0	17
34	Interchg Agr Energy	E8760	557	1,054	389	658	52	606	534	72	0	0	7
35	Tot Wis Interchg Purch			4,096	1,486	2,586	198	2,388	2,083	305	0	0	24
36	**Tot Purchased Power**			34,350	12,332	21,829	1,645	20,184	17,504	2,680	0	0	189
	Other Production		500,502,505-507 509-514,517-519,520, 523-525,528-532,535, 539,543-546,548-550 552-554,556,557 575.1-575.8										
37	Capacity Related	D10C		6,796	2,286	4,489	303	4,185	3,511	675	0	0	21
38	Energy Related	E8760		25,466	9,400	15,898	1,256	14,642	12,897	1,745	0	0	168
39	Total Other Produc	21.07%		32,262	11,686	20,387	1,560	18,827	16,407	2,420	0	0	189
40	**Total Production**			99,537	36,171	62,771	4,828	57,943	50,586	7,357	0	0	595
41	**Transmission Exp**	D10T	560-563, 565-568 570-573	17,569	6,255	11,214	827	10,387	8,821	1,566	0	0	101

Northern States Power Company

North Dakota 2021 Proposed CCOSS ($000) - Includes Fuel Correction

Highlighted values have been revised.

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**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Supervision & Eng'rg	ZDTS	580,590	924	509	314	56	258	221	37	0	0	101
2	Load Dispatching	T20D80	581	79	30	48	4	45	37	8	0	0	1
3	Substations	P61	582,591,592	458	181	273	22	251	208	43	0	0	5
4	Overhead Lines	POL	583,593	2,284	1,403	743	132	612	518	94	0	0	137
5	Underground Lines	PUL	584, 594	1,474	1,061	409	93	315	268	48	0	0	5
6	Line Transformers	P68	595	3	2	1	0	1	1	0	0	0	0
7	Meters	C12WM	586,597,598	273	164	108	34	74	71	3	0	0	0
8	Customer Install'n	OXDTS	587	290	169	94	17	77	65	12	0	0	27
9	Street Lighting	Dir Assign	585,596	312	0	0	0	0	0	0	0	0	312
10	Miscellaneous	OXDTS	588	2,143	1,251	695	125	570	484	86	0	0	197
11	Rents (Pole Attachmts)	POL	589	289	178	94	17	77	66	12	0	0	17
12	**Total Distribution**			8,529	4,948	2,780	500	2,280	1,939	341	0	0	801
13	**Customer Accounting**	C11WA	901-905	4,008	3,170	829	506	323	320	3	0	0	9
14	**Sales, Econ Dvlp & Other**	R01	912	119	48	69	7	63	57	6	0	0	1
	Admin & General												
15	Salaries	LABOR	920	6,096	2,458	3,513	321	3,192	2,769	423	0	0	125
16	Office Supplies	OXTS	921	4,196	1,645	2,498	216	2,281	1,983	298	0	0	53
17	Admin Transfer Credit	OXTS	922	(3,407)	(1,336)	(2,028)	(176)	(1,852)	(1,610)	(242)	0	0	(43)
18	Outside Services	LABOR	923	1,096	442	631	58	574	498	76	0	0	22
19	Property Insurance	NEPIS	924	414	168	241	21	221	191	30	0	0	4
20	Pensions & Benefits	LABOR	926	4,998	2,015	2,880	263	2,617	2,270	347	0	0	102
21	Injuries & Claims	LABOR	925	842	340	485	44	441	382	58	0	0	17
22	Regulatory Exp	R01; R02	928	34	14	20	2	18	16	2	0	0	0
23	General Advertising	OXTS	930.1	38	15	23	2	21	18	3	0	0	0
24	Contributions	OXTS		0	0	0	0	0	0	0	0	0	0
25	Misc General Exp	OXTS	929, 930.2	(37)	(14)	(22)	(2)	(20)	(17)	(3)	0	0	(0)
26	Rents	OXTS	931	2,458	963	1,463	127	1,336	1,161	175	0	0	31
27	Maint of General Plant	OXTS	935	54	21	32	3	30	26	4	0	0	1
28	Total			16,782	6,732	9,737	880	8,857	7,686	1,171	0	0	313
	Cust Service & Info												
29	Cust Assist Exp - Non-CIP	C11P10	908	233	141	89	16	73	64	9	0	0	3
30	CIP Total	E99XCIP	908	0	0	0	0	0	0	0	0	0	0
31	Instructional Advertising	C11P10	909	51	31	19	4	16	14	2	0	0	1
32	Total			284.060	172	109	20	89	78	11	0	0	4
33	Amortizations	LABOR		6,232	2,513	3,591	328	3,263	2,830	432	0	0	127
34	**Total O&M Expense**			153,060	60,009	91,100	7,896	83,204	72,317	10,887	0	0	1,951

Northern States Power Company

North Dakota 2021 Proposed CCOSS ($000) - Includes Fuel Correction

Highlighted values have been revised.

Book Depreciation

		Alloc	FERC Accounts	1=2+3+10 ND	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	D10C		8,450	2,843	5,581	377	5,204	4,365	839	0	0	26
2	Base Load	E8760		25,818	9,530	16,118	1,274	14,844	13,075	1,769	0	0	170
3	Total		403,413	34,267	12,372	21,699	1,651	20,048	17,440	2,608	0	0	196
	Transmission												
4	Gen Step Up Base	E8760		104	38	65	5	60	53	7	0	0	1
5	Gen Step Up Peak	D10C		62	21	41	3	38	32	6	0	0	0
6	Total Gen Step Up			166	59	106	8	98	85	13	0	0	1
7	Bulk Transmission	D10T		4,651	1,656	2,969	219	2,750	2,335	415	0	0	27
8	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
9	Direct Assign	Dir Assign		1	0	1	0	1	0	1	0	0	0
10	Total		403,413	4,818	1,715	3,076	227	2,849	2,420	429	0	0	28
	Distribution												
11	Generat Step Up	STRATH		5	2	3	0	3	2	0	0	0	0
12	Bulk Transmission	D10T		3	1	2	0	2	1	0	0	0	0
13	Distrib Function	D60Sub		861	340	512	41	472	391	80	0	0	9
14	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
15	Total Substations		403,413	868	342	517	41	476	395	81	0	0	9
16	Overhead Lines	POL		1,457	895	474	84	390	330	60	0	0	87
17	Underground	PUL		2,493	1,794	691	158	533	453	80	0	0	8
18	Line Transformers	P68		672	468	201	49	152	145	7	0	0	3
19	Services	P69		1,144	1,059	85	50	35	35	0	0	0	0
20	Meters	C12WM		273	164	108	34	74	71	3	0	0	0
21	Street Lighting	P73		151	0	0	0	0	0	0	0	0	151
22	Total		403,413	7,058	4,723	2,077	416	1,660	1,429	231	0	0	259
23	**General & Common Plant**	PTD	403,413	8,400	3,400	4,918	420	4,498	3,895	602	0	0	82
24	**Total Book Deprec**		403,404	54,544	22,211	31,769	2,714	29,055	25,184	3,871	0	0	564

Real Estate & Property Tax

		Alloc	FERC Accounts	1=2+3+10 ND	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	D10C		1,706	574	1,127	76	1,051	881	169	0	0	5
26	Base Load	E8760		4,889	1,805	3,052	241	2,811	2,476	335	0	0	32
27	Total		408.1	6,595	2,379	4,179	317	3,862	3,357	504	0	0	37
	Transmission												
28	Gen Step Up Base	E8760		81.8044	30	51	4	47	41	6	0	0	1
29	Gen Step Up Peak	D10C		30.8806	10	20	1	19	16	3	0	0	0
30	Total Gen Step Up			112.6850	41	71	5	66	57	9	0	0	1
31	Bulk Transmission	D10T		2,963.5650	1,055	1,892	140	1,752	1,488	264	0	0	17
32	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
33	Direct Assign	Dir Assign		1	0	1	0	1	0	1	0	0	0
34	Total		408.1	3,077.036	1,096	1,964	145	1,819	1,545	274	0	0	18
	Distribution												
35	Generat Step Up	STRATH		2	1	1	0	1	1	0	0	0	0
36	Bulk Transmission	D10T		1	0	1	0	1	1	0	0	0	0
37	Distrib Function	D60Sub		331	131	197	16	181	150	31	0	0	3
38	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
39	Total Substations			334	132	199	16	183	152	31	0	0	3
40	Overhead Lines	POL		368	226	120	21	99	83	15	0	0	22
41	Underground	PUL		671	483	186	42	143	122	22	0	0	2
42	Line Transformers	P68		236	164	71	17	53	51	3	0	0	1
43	Services	P69		130	121	10	6	4	4	0	0	0	0
44	Meters	C12WM		57	35	23	7	16	15	1	0	0	0
45	Street Lighting	P73		27	0	0	0	0	0	0	0	0	27
46	Total		408.1	1,823	1,160	607	110	498	427	71	0	0	56
47	**General & Common Plant**	PTD	408.1	0	0	0	0	0	0	0	0	0	0
48	**Tot Rl Est & Pr Tax**			11,495	4,634	6,750	572	6,178	5,329	849	0	0	111
49	Gross Earnings Tax	R01; R02		0	0	0	0	0	0	0	0	0	0
50	Payroll Taxes	LABOR		2,032	819	1,171	107	1,064	923	141	0	0	42
51	**Tot Non-Inc Taxes**			13,527	5,453	7,921	679	7,242	6,252	990	0	0	152

North Dakota 2021 Proposed CCOSS ($000) - Includes Fuel Correction

Highlighted values have been revised.

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**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10C		(423)	(142)	(279)	(19)	(260)	(218)	(42)	0	0	(1)
2	Nuclear Fuel	E8760		(169)	(62)	(106)	(8)	(97)	(86)	(12)	0	0	(1)
3	Base Load	E8760		4,836	1,785	3,019	239	2,781	2,449	331	0	0	32
4	Total		410, 411	4,244	1,580	2,634	211	2,423	2,145	278	0	0	29
	Transmission												
5	Gen Step Up Base	E8760		92	34	57	5	53	47	6	0	0	1
6	Gen Step Up Peak	D10C		33	11	22	1	20	17	3	0	0	0
7	Total Gen Step Up			125	45	79	6	73	63	10	0	0	1
8	Bulk Transmission	D10T		927	330	592	44	548	465	83	0	0	5
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		410, 411	1,052	375	671	50	621	529	92	0	0	6
	Distribution												
12	Generat Step Up	STRATH		(2)	(1)	(1)	(0)	(1)	(1)	(0)	0	0	(0)
13	Bulk Transmission	D10T		(1)	(0)	(0)	(0)	(0)	(0)	(0)	0	0	(0)
14	Distrib Function	D60Sub		103	41	61	5	57	47	10	0	0	1
15	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
16	Total Substations			101	40	60	5	55	46	9	0	0	1
17	Overhead Lines	POL		(65)	(40)	(21)	(4)	(18)	(15)	(3)	0	0	(4)
18	Underground	PUL		(417)	(300)	(116)	(26)	(89)	(76)	(13)	0	0	(1)
19	Line Transformers	P68		(99)	(69)	(30)	(7)	(22)	(21)	(1)	0	0	(0)
20	Services	P69		(136)	(126)	(10)	(6)	(4)	(4)	0	0	0	0
21	Meters	C12WM		(20)	(12)	(8)	(3)	(6)	(5)	(0)	0	0	(0)
22	Street Lighting	P73		(29)	0	0	0	0	0	0	0	0	(29)
23	Total		410, 411	(665)	(507)	(125)	(41)	(84)	(76)	(8)	0	0	(33)
24	**General & Common Plant**	PTD	410, 411	104	42	61	5	55	48	7	0	0	1
25	**Net Operating Loss (NOL) Carry**	NEPIS		(12,400)	(5,045)	(7,233)	(623)	(6,610)	(5,711)	(899)	0	0	(123)
26	**Non - Plant Related**	LABOR	410, 411	301	121	173	16	158	137	21	0	0	6
27	**Tot Prov For Defer**			(7,365)	(3,434)	(3,818)	(382)	(3,436)	(2,928)	(509)	0	0	(113)

Inv Tax Credit; Total Oper Exp

				ND	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
	Production												
28	Peaking Plant	D10C		(18)	(6)	(12)	(1)	(11)	(10)	(2)	0	0	(0)
29	Base Load	E8760		(38)	(14)	(24)	(2)	(22)	(19)	(3)	0	0	(0)
30	Total		411	(57)	(20)	(36)	(3)	(33)	(29)	(4)	0	0	(0)
	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	D10T		(11)	(4)	(7)	(1)	(6)	(5)	(1)	0	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	(11)	(4)	(7)	(1)	(6)	(5)	(1)	0	0	(0)
	Distribution												
38	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
39	Bulk Transmission	D10T		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		0	0	0	0	0	0	0	0	0	0
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	0	0	0	0	0	0	0	0	0	0
50	**General & Common Plant**	PTD	411	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0	0	(0)
51	**Net Inv Tax Credit**			(68)	(24)	(43)	(3)	(40)	(34)	(5)	0	0	(0)
52	**Total Operating Exp**			**213,697**	**84,215**	**126,929**	**10,904**	**116,025**	**100,791**	**15,234**	**0**	**0**	**2,554**
53A	**Pres Op Inc Before Inc Tax**			**32,279.267**	**14,300**	**18,215**	**2,390**	**15,825**	**17,291**	**(1,466)**	**0**	**0**	**(236)**
53B	**Prop Op Inc Before Inc Tax**			**51,477**	**22,125**	**29,254**	**2,754**	**26,501**	**26,924**	**(423)**	**0**	**0**	**98**

North Dakota 2021 Proposed CCOSS ($000) - Includes Fuel Correction

Highlighted values have been revised.

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**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10C		8,496	2,858	5,612	379	5,232	4,389	843	0	0	26
2	Nuclear Fuel	E8760		6,535	2,412	4,080	322	3,758	3,310	448	0	0	43
3	Base Load	E8760		50,010	18,459	31,222	2,467	28,755	25,327	3,427	0	0	329
4	Total		tax books	65,042	23,730	40,914	3,169	37,745	33,026	4,719	0	0	399
	Transmission												
5	Gen Step Up Base	E8760		452	167	282	22	260	229	31	0	0	3
6	Gen Step Up Peak	D10C		163	55	108	7	101	84	16	0	0	1
7	Total Gen Step Up			615	222	390	30	360	313	47	0	0	3
8	Bulk Transmission	D10T		8,550	3,044	5,457	403	5,055	4,293	762	0	0	49
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		2	0	2	0	2	0	2	0	0	0
11	Total		tax books	9,168	3,266	5,850	432	5,417	4,606	811	0	0	52
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10T		1	0	1	0	1	1	0	0	0	0
14	Distrib Function	D60Sub		1,311	518	781	62	719	596	122	0	0	13
15	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
16	Total Substations			1,313	518	781	62	719	597	123	0	0	13
17	Overhead Lines	POL		1,270	781	413	73	340	288	52	0	0	76
18	Underground	PUL		1,598	1,150	443	101	342	290	51	0	0	5
19	Line Transformers	P68		1,043	726	312	76	236	225	11	0	0	5
20	Services	P69		280	259	21	12	8	8	0	0	0	0
21	Meters	C12WM		246	148	98	31	67	64	2	0	0	0
22	Street Lighting	P73		81	0	0	0	0	0	0	0	0	81
23	Total		tax books	5,831	3,583	2,068	355	1,713	1,472	240	0	0	180
24	**General & Common Plant**	PTD	tax books	10,813	4,377	6,330	541	5,790	5,015	775	0	0	106
25	Net Operating Loss (NOL) Carry F	NEPIS		0	0	0	0	0	0	0	0	0	0
26	**Total Tax Deprec**			90,854	34,955	55,162	4,497	50,665	44,119	6,546	0	0	737
27	Interest Expense		427,431	13,470.64	5,469	7,868	678	7,190	6,218	972	0	0	134
28	Other Tax Timing Differ	LABOR		(283)	(114)	(163)	(15)	(148)	(128)	(20)	0	0	(6)
29	Meals & Enter	LABOR		79	32	46	4	41	36	5	0	0	2
30	Total Tax Deductions			104,121	40,342	62,912	5,164	57,748	50,245	7,503	0	0	867
	Inc Tax Additions												
31	Book Depreciation			54,544	22,211	31,769	2,714	29,055	25,184	3,871	0	0	564
32	Deferred Inc Tax & ITC			(7,432.96)	(3,458)	(3,861)	(385)	(3,476)	(2,962)	(514)	0	0	(114)
33	Nuclear Fuel Book Burn	E8760		7,025	2,593	4,386	347	4,039	3,558	481	0	0	46
34	Tax Capitalized Leases	PTD		2,953	1,195	1,729	148	1,581	1,369	212	0	0	29
35	Avoided Tax Interest	RTBASE		1,117	453	652	56	596	516	81	0	0	11
36	Total Tax Additions			58,206	22,994	34,675	2,879	31,795	27,665	4,130	0	0	537
37	**Total Inc Tax Adjustments**			(45,916)	(17,348)	(28,238)	(2,285)	(25,953)	(22,580)	(3,373)	0	0	(330)
38A	**Pres Taxable Net Income**			(13,636)	(3,048)	(10,023)	105	(10,128)	(5,289)	(4,839)	0	0	(566)
38B	**Prop Taxable Net Income**			5,561	4,777	1,016	468	548	4,344	(3,796)	0	0	(233)
39A	Pres Fed & State Inc Tax			(2,962)	(595)	(2,232)	44	(2,276)	(1,122)	(1,155)	0	0	(134)
39B	Prop Fed & State Inc Tax			1,723	1,314	462	133	329	1,229	(900)	0	0	(53)
40A	Pres Preliminary Return	(total); BASE		35,241	14,895	20,447	2,346	18,101	18,413	(311)	0	0	(101)
40B	Prop Preliminary Return	(total); BASE		49,754	20,811	28,792	2,621	26,172	25,695	477	0	0	151
41	Total AFUDC			0	0	0	0	0	0	0	0	0	0
42A	**Present Total Return**			35,241	14,895	20,447	2,346	18,101	18,413	(311)	0	0	(101)
42B	**Proposed Total Return**			49,754	20,811	28,792	2,621	26,172	25,695	477	0	0	151
43A	**Pres % Return on Rate Base**			5.21%	5.42%	5.17%	6.89%	5.01%	5.89%	-0.64%	0.00%	0.00%	-1.50%
43B	**Prop % Return on Rate Base**			7.35%	7.57%	7.28%	7.69%	7.24%	8.22%	0.98%	0.00%	0.00%	2.24%
44A	**Present Common Return**			21,771	9,426	12,579	1,668	10,911	12,195	(1,283)	0	0	(235)
44B	**Proposed Common Return**			36,283	15,342	20,925	1,943	18,982	19,477	(495)	0	0	17
45A	**Pres % Ret on Common Rt Base**			6.13%	6.53%	6.06%	9.32%	5.75%	7.43%	-5.01%	0.00%	0.00%	-6.66%
45B	**Prop % Ret on Common Rt Base**			10.21%	10.63%	10.08%	10.86%	10.01%	11.87%	-1.93%	0.00%	0.00%	0.47%

North Dakota 2021 Proposed CCOSS ($000) - Includes Fuel Correction

Highlighted values have been revised.

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**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10C		0	0	0	0	0	0	0	0	0	0
2	Nuclear Fuel	E8760		0	0	0	0	0	0	0	0	0	0
3	Base Load	E8760		0	0	0	0	0	0	0	0	0	0
4	Total		419.1,432	0	0	0	0	0	0	0	0	0	0
	Transmission												
5	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10C		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	D10T		0	0	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0	0	0	0
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10T		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
15	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
16	Total Substations			0	0	0	0	0	0	0	0	0	0
17	Overhead Lines	POL		0	0	0	0	0	0	0	0	0	0
18	Underground	PUL		0	0	0	0	0	0	0	0	0	0
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		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		419.1,432	0	0	0	0	0	0	0	0	0	0
24	**General & Common Plant**	PTD	419.1,432	0	0	0	0	0	0	0	0	0	0
25	**Total AFUDC**			0	0	0	0	0	0	0	0	0	0

Labor Allocator

	Production												
26	Other Prod - Cap	D10S		5,047	1,698	3,333	225	3,108	2,607	501	0	0	16
27	Other Prod - Ene	E8760		14,460	5,337	9,027	713	8,314	7,323	991	0	0	95
28	Total		500 through 557	19,506	7,035	12,360	939	11,422	9,930	1,492	0	0	111
	Transmission												
29	Stepup Subtrans	P5161A		68	24	43	3	40	35	5	0	0	0
30	Bulk Power Subs	D10T		1,796	639	1,147	85	1,062	902	160	0	0	10
31	Total		560 through 571	1,864	664	1,190	88	1,102	936	165	0	0	11
	Distribution												
32	Superv & Eng	ZDTS	580, 590	776	428	264	47	217	185	31	0	0	85
33	Load Dispatch	D10T	581	40	14	25	2	23	20	4	0	0	0
34	Substation	P61	582, 592	294	116	175	14	161	134	27	0	0	3
35	Overhead Lines	POL	583, 593	721	443	235	42	193	163	30	0	0	43
36	Underground Lines	PUL	584, 594	344	247	95	22	74	62	11	0	0	1
37	Line Transformer	P68	595	0	0	0	0	0	0	0	0	0	0
38	Meter	C12WM	586, 597	293	176	116	37	79	76	3	0	0	0
39	Cust Installation	ZDTS	587	257	142	88	16	72	62	10	0	0	28
40	Street Lighting	P73	585, 596	169	0	0	0	0	0	0	0	0	169
41	Miscellaneous	OXDTS	588	861	502	279	50	229	194	34	0	0	79
42	Total			3,755	2,069	1,277	229	1,048	898	150	0	0	409
43	**Cust Accounting**	C11WA	901,902,903,904,905	930	735	192	117	75	74	1	0	0	2
44	**Sales Expense**	C11P10	912	0	0	0	0	0	0	0	0	0	0
45	**Admin & General**	LABOR	920,921,922,923,924,	11,227	4,527	6,470	592	5,878	5,099	779	0	0	229
46	**Service & Inform**	C11P10	908, 909	20	12	8	1	6	6	1	0	0	0
47	**Labor**			37,302	15,043	21,497	1,966	19,531	16,943	2,588	0	0	762

North Dakota 2021 Proposed CCOSS ($000) - Includes Fuel Correction Highlighted values have been revised. Page 13 of 14

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	
INTERNAL ALLOCATORS		Intern:	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	50% Cus, 50% Prod Plt	C11P10	100.00%	60.42%	38.23%	6.92%	31.31%	27.55%	3.76%	0.00%	0.00%	1.35%
2	Peaking Plant Capacity	D10S	100.00%	33.64%	66.05%	4.46%	61.58%	51.66%	9.93%	0.00%	0.00%	0.31%
3	57% Dmd; 43% Energy: Sales & I	D57E43	100.00%	36.91%	62.43%	4.93%	57.50%	50.64%	6.85%	0.00%	0.00%	0.66%
4	40% Dmd; 60% Energy: CIP	D40E60	100.00%	36.91%	62.43%	4.93%	57.50%	50.64%	6.85%	0.00%	0.00%	0.66%
5	20%D10T; 80%D60Sub	T20D80	100.00%	37.84%	61.36%	4.62%	56.74%	47.04%	9.69%	0.00%	0.00%	0.81%
6	Labor w/o (or w/) A&G	LABOR	100.00%	40.33%	57.63%	5.27%	52.36%	45.42%	6.94%	0.00%	0.00%	2.04%
7	Net Plant In Service	NEPIS	100.00%	40.68%	58.33%	5.02%	53.30%	46.05%	7.25%	0.00%	0.00%	0.99%
8	Dis O&M w/o Sup & Misc	OXDTS	100.00%	58.37%	32.42%	5.83%	26.59%	22.59%	3.99%	0.00%	0.00%	9.21%
9	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	100.00%	39.21%	59.52%	5.16%	54.36%	47.25%	7.11%	0.00%	0.00%	1.27%
10	Production Plant	P10	100.00%	36.24%	63.18%	4.84%	58.34%	50.85%	7.49%	0.00%	0.00%	0.59%
11	Production Plant Wo Nuclear	P10WoN	100.00%	36.07%	63.37%	4.81%	58.55%	50.91%	7.65%	0.00%	0.00%	0.57%
12	Total P51 & P61A	P5161A	100.00%	36.02%	63.41%	4.81%	58.61%	50.92%	7.69%	0.00%	0.00%	0.56%
13	Distribution Plant	P60	100.00%	63.62%	33.32%	6.01%	27.31%	23.41%	3.90%	0.00%	0.00%	3.06%
14	Distr Substn Plant	P61	100.00%	39.43%	59.56%	4.73%	54.83%	45.51%	9.32%	0.00%	0.00%	1.00%
15	Line Transformer Plant	P68	100.00%	69.64%	29.91%	7.25%	22.66%	21.56%	1.10%	0.00%	0.00%	0.45%
16	Services Plant	P69	100.00%	92.57%	7.43%	4.41%	3.02%	3.02%	0.00%	0.00%	0.00%	0.00%
17	Dist Plt Overhead Lines	POL	100.00%	61.45%	32.54%	5.76%	26.78%	22.67%	4.12%	0.00%	0.00%	6.01%
18	Real Est & Property Tax	PT0	100.00%	40.31%	58.72%	4.97%	53.75%	46.36%	7.39%	0.00%	0.00%	0.96%
19	Produc, Trans & Distrib	PTD	100.00%	40.48%	58.54%	5.00%	53.54%	46.37%	7.17%	0.00%	0.00%	0.98%
20	Dist Plt Undground Lines	PUL	100.00%	71.96%	27.72%	6.33%	21.38%	18.16%	3.22%	0.00%	0.00%	0.32%
21	Rate Base (Non-Column)	RTBASE	100.00%	40.60%	58.41%	5.03%	53.37%	46.16%	7.21%	0.00%	0.00%	0.99%
22	Stratified Hydro Baseload	STRATH	100.00%	36.36%	63.04%	4.85%	58.19%	50.82%	7.37%	0.00%	0.00%	0.60%
23	Transmission & Distrib	TD	100.00%	48.77%	49.49%	5.32%	44.17%	37.62%	6.54%	0.00%	0.00%	1.74%
24	Labor Dis w/o Sup & Eng	ZDTS	100.00%	55.10%	34.01%	6.10%	27.91%	23.90%	4.01%	0.00%	0.00%	10.89%

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
INTERNAL DATA			**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
25	Labor w/o A&G	LABOR(S)	26,075	10,515	15,027	1,374	13,653	11,844	1,809	0	0	533
26	Dis O&M w/o Sup, Cust Install & I	OXDTS	5,172	3,019	1,677	302	1,375	1,168	207	0	0	476
27	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	149,723	58,700	89,114	7,724	81,391	70,740	10,651	0	0	1,909
28	Total P51 & P61A	P5161A	9,017	3,248	5,718	433	5,285	4,591	693	0	0	51
29	Produc, Trans & Distrib	PTD	1,339,282	542,134	784,060	66,967	717,093	621,087	96,005	0	0	13,088
30	Transmission & Distrib	TD	453,345	221,097	224,356	24,122	200,234	170,563	29,671	0	0	7,892
31	Labor Dis w/o Sup & Eng, Cust In	ZDTS	2,721	1,499	926	166	760	650	109	0	0	296

North Dakota 2021 Proposed CCOSS ($000) - Includes Fuel Correction

Highlighted values have been revised.

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
EXTERNAL ALLOCATORS		Extern:	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Customers - Ave Monthly	C11	100.00%	84.60%	13.28%	9.00%	4.27%	4.24%	0.03%	0.00%	0.00%	2.12%
2	Cust Acctg Wtg Factor	C11WA	100.00%	79.08%	20.68%	12.62%	8.06%	7.98%	0.08%	0.00%	0.00%	0.24%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	60.19%	39.71%	12.59%	27.12%	26.11%	1.01%	0.00%	0.00%	0.10%
4	Sec & Pri Customers	C61PS	100.00%	86.24%	13.51%	9.13%	4.38%	4.34%	0.03%	0.00%	0.00%	0.26%
5	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	100.00%	93.51%	6.49%	5.57%	0.92%	0.92%	0.01%	0.00%	0.00%	0.00%
6	C62Sec, w/o Ltg & C/I Undergrou	C62NL	100.00%	93.37%	6.63%	4.49%	2.14%	2.14%	0.00%	0.00%	0.00%	0.00%
7	Secondary Customers	C62Sec	100.00%	86.26%	13.48%	9.13%	4.34%	4.34%	0.00%	0.00%	0.00%	0.26%
8	Summer Peak Resp KW	D10S	100.00%	31.34%	68.66%	4.17%	64.49%	53.37%	11.12%	0.00%	0.00%	0.00%
9	Transmission Demand %	D10T	100.00%	35.60%	63.83%	4.71%	59.12%	50.21%	8.91%	0.00%	0.00%	0.57%
10	Winter Peak Resp KW	D10W	100.00%	41.68%	56.94%	5.47%	51.47%	45.70%	5.76%	0.00%	0.00%	1.39%
11	Alternative Production Allocator	D10C	100.00%	33.64%	66.05%	4.46%	61.58%	51.66%	9.93%	0.00%	0.00%	0.31%
12	Sec, Pri & TT, Class Coin kW @ :	D60Sub	100.00%	39.46%	59.53%	4.73%	54.80%	45.46%	9.34%	0.00%	0.00%	1.01%
13	Sec & Pri, Cl Coin kW (no Min Sy	D61PS	100.00%	36.18%	62.96%	4.16%	58.80%	48.66%	10.15%	0.00%	0.00%	0.85%
14	Pri & Sec Coin kW Served w/ 1 P	D61PS1Ph	100.00%	72.24%	27.76%	4.67%	23.09%	18.89%	4.19%	0.00%	0.00%	0.00%
15	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	100.00%	79.13%	20.87%	3.05%	17.82%	17.82%	0.00%	0.00%	0.00%	0.00%
16	Sec, Class Coin kW (w/o Min Sys	D62SecL	100.00%	51.66%	47.70%	4.99%	42.70%	42.70%	0.00%	0.00%	0.00%	0.64%
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%	36.91%	62.43%	4.93%	57.50%	50.64%	6.85%	0.00%	0.00%	0.66%
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	Present Rev	R01	100.00%	40.57%	58.43%	5.51%	52.92%	47.70%	5.22%	0.00%	0.00%	1.00%
21	Late Fee Revenue Allocator	LateFee	100.00%	87.79%	12.20%	3.04%	9.16%	9.13%	0.03%	0.00%	0.00%	0.01%

			6	**7**	**11**	**12**	**13**	**15**	**16**	**17**	**18**	**36**
			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
EXTERNAL DATA			**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
22	Customers - B Basis	C10	93,865	80,944	12,677	8,570	4,107	4,076	31	0	0	243
23	Cust - Ave Monthly (C10-Area Lt)	C11	96,144	81,342	12,764	8,657	4,107	4,076	31	0	0	2,038
2	Mo Cus Wtd By Cus Acct	C11WA	102,860	81,342	21,276	12,985	8,291	8,207	84	0	0	242
25	Cust Acctg Wtg Factor	C11WAF	7.34	1.00	6.22	1.50	4.72	2.01	2.71	0.00	0.00	0.12
26	Cust-Ave Mo (C11 w/ Dir Assign :	C12	94,230	81,342	12,764	8,657	4,107	4,076	31	0	0	124
27	Mo Cus Wtd By Mtr Invest	C12WM	12,656,917	7,617,987	5,026,114	1,593,062	3,433,051	3,304,939	128,112	0	0	12,816
28	Meter Invest / Cust Factor	C12WMF	5,324	94	5,127	184	4,943	811	4,133	0	0	103
29	Sec & Pri Customers	C61PS	93,865	80,944	12,677	8,570	4,107	4,076	31	0	0	243
30	% Served by Primary Single Phase		0.0%	71.60%	0.00%	40.26%	0.00%	13.93%	14.81%	0.00%	0.00%	44.01%
31	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	61,976	57,954	4,022	3,450	572	568	5	0	0	0
32	C62Sec, w/o Ltg & C/I Undergrou	C62NL	86,688	80,944	5,744	3,892	1,851	1,851	0	0	0	0
33	Secondary Customers	C62Sec	93,834	80,944	12,646	8,570	4,076	4,076	0	0	0	243
34	Summer Peak Resp KW	D10S	414	130	284	17	267	221	46	0	0	0
35	Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	3,560,028	6,382,730	470,854	5,911,876	5,020,560	891,317	0	0	57,242
36	Winter Peak Resp KW	D10W	332	138	189	18	171	152	19	0	0	5
37	Alternative Production Allocator	D10C	10,000,000	3,364,298	6,604,749	446,334	6,158,415	5,165,684	992,731	0	0	30,953
38	Sec, Pri & TT, Class Coin kW @ :	D60Sub	492,965	194,540	293,455	23,310	270,145	224,118	46,027	0	0	4,970
39	Sec & Pri, Class Coin kW (w/o Mi	D61PS	453,056	163,938	285,253	18,844	266,409	220,444	45,965	0	0	3,866
40	Pri & Sec Coin kW Served w/ 1 P	D61PS1Ph	162,467	117,374	45,093	7,586	37,507	30,697	6,810	0	0	0
41	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	941,532	745,034	196,499	28,754	167,745	167,745	0	0	0	0
42	Sec, Class Coin kW (w/o Min Sys	D62SecL	10,000,000	5,166,364	4,769,801	499,350	4,270,451	4,270,451	0	0	0	63,835
43	Annual Billing kW	D99	3,286.718	0	3,287	0	3,287	2,990	296	0	0	0
44	Summer Billing kW	D99S	1,137.231	0	1,137	0	1,137	1,032	106	0	0	0
45	Winter Billing kW	D99W	2,149.487	0	2,149	0	2,149	1,959	191	0	0	0
46	Non-Coinc Pk Second	DN-Sec	1,181,528	745,034	432,629	63,307	369,322	369,322	0	0	0	3,866
47	MWh Sales	E99	2,136,485	779,209	1,339,342	102,502	1,236,839	1,086,222	150,618	0	0	17,934

Northern States Power Company

Test Year Ending December 31, 2021
Primary Distribution Cost Allocator Calculations

Case No. PU-20-441
Exhibit___(MAP-1), **REVISED** Schedule 5

Highlighted values have been revised.

					Customer Class					
Line	**Primary Distribution Cost**	**Allocator Derivation**	**Allocator Label**	**ND**	**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	93,865	80,944	8,570	4,076	31	243
2	Capacity Portion of **Multi-Phase** Primary Lines	Class Coincident Peak Demands	D61PS	453,056	163,938	18,844	220,444	45,965	3,866
3	% of Customers Served by Primary **Single Phase** Lines				71.6%	40.3%	13.9%	14.8%	44.0%
4	Customer Portion of **Single-Phase** Primary Lines	line 1 x line 3	C61PS1Ph	61,976	57,954	3,450	568	5	0
5	Capacity Portion of Single-Phase Primary Lines	line 2 x line 3	D61PS1Ph	162,467	117,374	7,586	30,697	6,810	0
6	Customer Portion of **Multi-Phase** Primary Lines	Cost Allocator %	C61PS	100.0%	86.2%	9.1%	4.3%	0.0%	0.3%
7	Capacity Portion of **Multi-Phase** Primary Lines	Cost Allocator %	D61PS	100.0%	36.2%	4.2%	48.7%	10.1%	0.9%
8	Customer Portion of **Single-Phase** Primary Lines	Cost Allocator %	C61PS1Ph	100.0%	93.5%	5.6%	0.9%	0.0%	0.0%
9	Capacity Portion of **Single-Phase** Primary Lines	Cost Allocator %	D61PS1Ph	100.0%	72.2%	4.7%	18.9%	4.2%	0.0%

Highlighted values have been revised.

Results of Xcel Energy Minimum Distribution System & Zero Intercept Studies

Highlighted values have been revised.

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. In this rate case the Company has completed both Minimum System and Zero Intercept studies. This exhibit describes the steps the Company has taken to complete these studies.

Highlighted values have been revised.

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 plant 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 were determined by the Company's Distribution Engineering area according to its field experience and its evaluation of the smallest practical-sized equipment inventories held in the Company's inventory.

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 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 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.

Highlighted values have been revised.

- 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

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 of nearly 12,000 distribution work orders that were completed over an 11 year period. 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).

The Company acquired the data for both studies from the following sources:

- Distribution Equipment Inventory - This data was obtained by querying all of the data available on conductors, cables, transformers and secondary equipment in the Company’s Geographic Information System (GIS) database. This data was then split into the following specific Property Units: Overhead (OH) Primary, Underground (UG) Primary, OH Secondary, UG Secondary, OH Transformers and UG Transformers.

Highlighted values have been revised.

These Property Units were then further divided into specific sizes and configurations (i.e. 1/0 AL 3ph under the UG Primary Property Unit). The total length (feet) in the GIS was calculated for each specific configuration of conductors and cables, and the total amount of units in the GIS was calculated for each specific configuration of transformers.

- Minimum Size of Distribution Equipment - The minimum-size conductor, cable, transformer, and secondary service equipment used in the Minimum System Study were selected by the Engineering Organization according to its field experience and its evaluation of the smallest practical-sized equipment inventories held in the Company's inventory. The "smallest practical-sized equipment" presently utilized on the Company's distribution system in Minnesota has been developed and refined over a number of decades as our industry has matured and progressed.

- Per Unit Installed Costs - To acquire the data needed to determine the installed unit costs, the GIS was queried for all Work Orders added to the database for an 11 year period. When new equipment such as a cable or a transformer is added to the GIS, or when existing equipment is changed, the equipment is associated with a specific Work Order number. The Work Order number is an identification number for the specific job that was done to install the equipment. Therefore, when the Work Orders were queried from the GIS, all of the specific equipment installed in those Work Orders was acquired. This provided a large dataset of specific jobs that have been done in the past five years, as well as what was installed in those jobs.

  To determine the costs associated with each Work Order, the Work Orders pulled from GIS were queried in the Company's financial management system. This query was able to pull the total cost for each Work Order, and the breakdown of how much was charged to each cost area (regular labor, overtime labor, equipment, stocked materials, etc). This then gave a breakdown of historic jobs, what was installed in those jobs, and how much the jobs cost.

  Using the Work Order and cost data, the Work Orders were then filtered down to those in which only one Property Unit and one specific configuration was installed (i.e., a Work Order that only installs 350 feet of 1/0 AL 3ph would be used for the study, but a Work Order that installs both 350 feet of 1/0 AL 3ph and 200 feet of 750 AL 3ph would be filtered out). This was done to ensure accuracy in calculating the installed unit cost for a single specific configuration because we could not parse out the costs for the two different configurations from the entire cost of a Work Order. After filtering, the cost from nearly 12,000 work orders were used to develop the per unit installed costs.

Highlighted values have been revised.

- Load Carrying Capacity of Distribution Equipment Configurations - The load-carrying capability was factored into the analysis using the unique load-carrying capacity value for each specific configuration. For transformers, this value was the nameplate kVA value. For conductors, cables and secondary equipment, this value was the ampacity. The values for ampacity of the various conductors, cables and secondary service equipment were acquired from the Company's Distribution design and construction manuals. For three-phase conductors and cables, this ampacity value was calculated as three times the single-phase value listed in the Company's Distribution Design and Construction manuals.

5. Analysis Results

The data and results of the minimum system and zero intercept studies are shown in Attachments A to P of Schedule 5.

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.

Highlighted values have been revised.

- 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

Highlighted values have been revised.

Zero Intercept Method Vs 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%

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%	63.1%
Overhead Secondary (used Zero Intercept result)	78.2%	21.8%
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%

Highlighted values have been revised.

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 3 on Page 13 of Michael Peppin's direct testimony). 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.

Highlighted values have been revised.

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 40 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

Highlighted values have been revised.

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%**	

Northern States Power Company Case No. PU-20-441

Exhibit___(MAP-1), **REVISED** Schedule 6

Inventory of Underground Secondary by Conductor Configuration Attachment B

Highlighted values have been revised.

Configuration 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

Highlighted values have been revised.

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%	

Northern States Power Company Case No. PU-20-441

Exhibit___(MAP-1), **REVISED** Schedule 6

Inventory of Overhead Primary by Conductor Configuration Attachment D

Highlighted values have been revised. Page 1 of 1

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	Cummulative % of 3 Phase Footage	% of All OH Primary	Cummulative % 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

Highlighted values have been revised.

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

Highlighted values have been revised.

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%	

Inventory of Primary Voltage Step-Down Transformers by Transformer Configuration

Highlighted values have been revised.

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

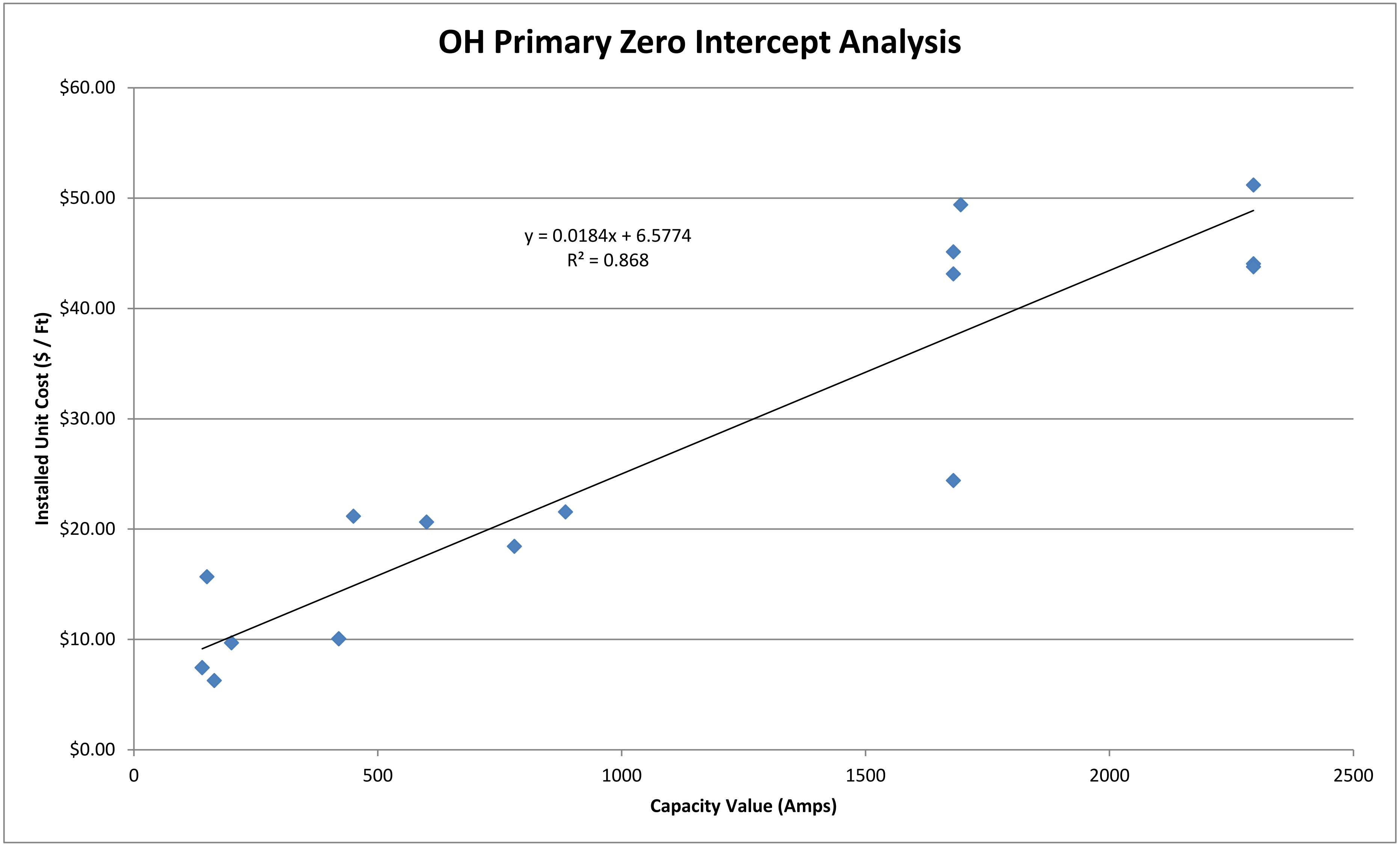
Overhead 2 Phase	Number OH 2 Phase	% of OH 2 Phase	Cumulative % of OH 2 Phase	% of All OH Step-Down Transformers	Load Carrying Capacity (kVA)	Installed Unit Cost	Total Replacement Costs
OH 2 phase 34.5/13.8 kV 1000 kVA	7	12.28%	12.28%	0.51%	1000	$66,139	$462,975
OH 2 phase 13.8/4.16 kV 500 kVA	4	7.02%	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

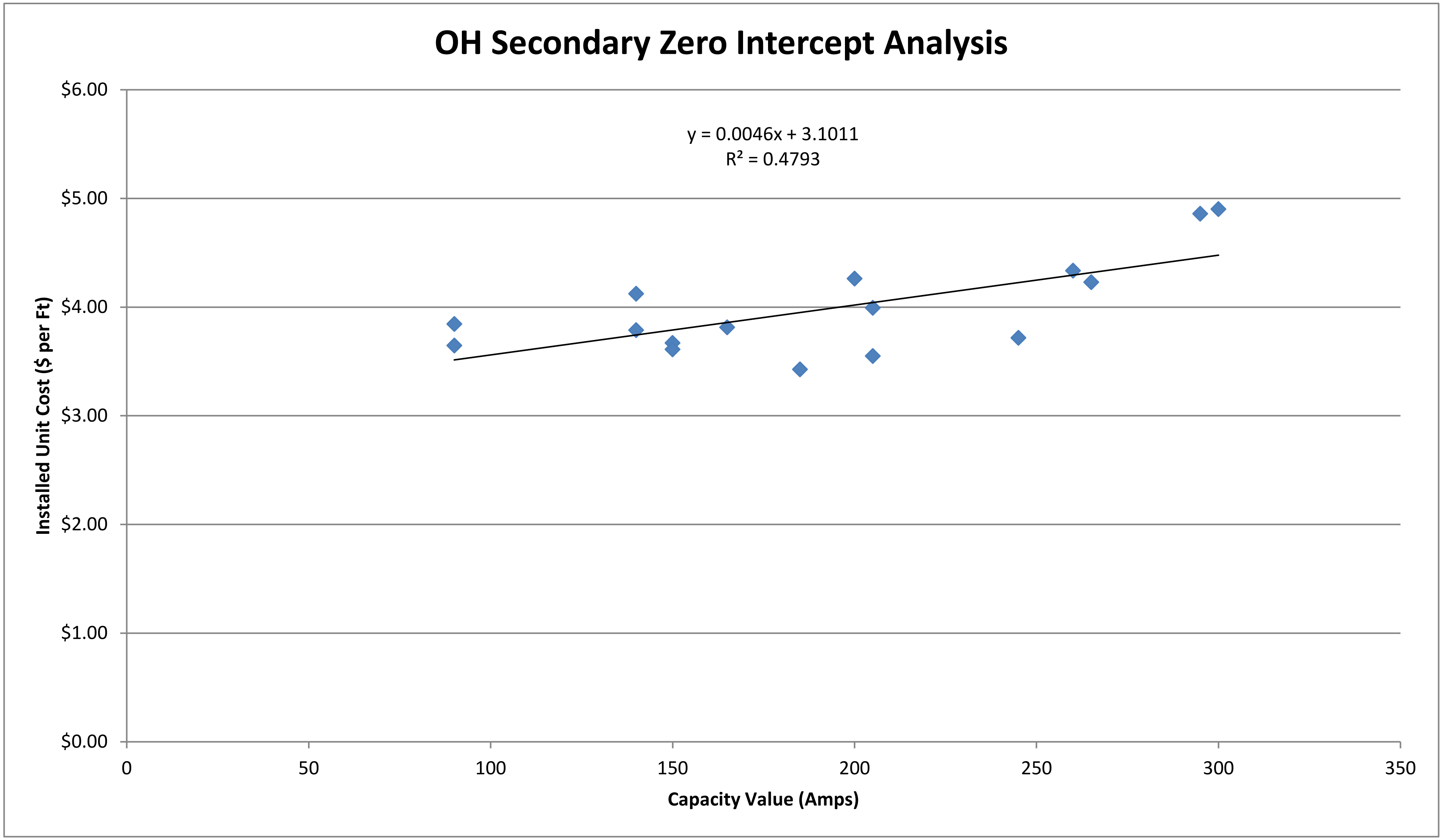
Underground 1 Phase	Number UG 1 Phase	% of UG 1 Phase	Cumulative % of UG 1 Phase	% of All UG Step-Down Transformers	Load Carrying Capacity (kVA)	Installed Unit Cost	Total Replacement Costs
UG 1 phase 19.92/7.2 kV 167 kVA	2	15.38%	15.38%	2.08%	167	$7,967	$15,933
UG 1 phase 19.92/7.97 kV 250 kVA	2	15.38%	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 Tran	**1,471**					$58,201	**$85,614,116**

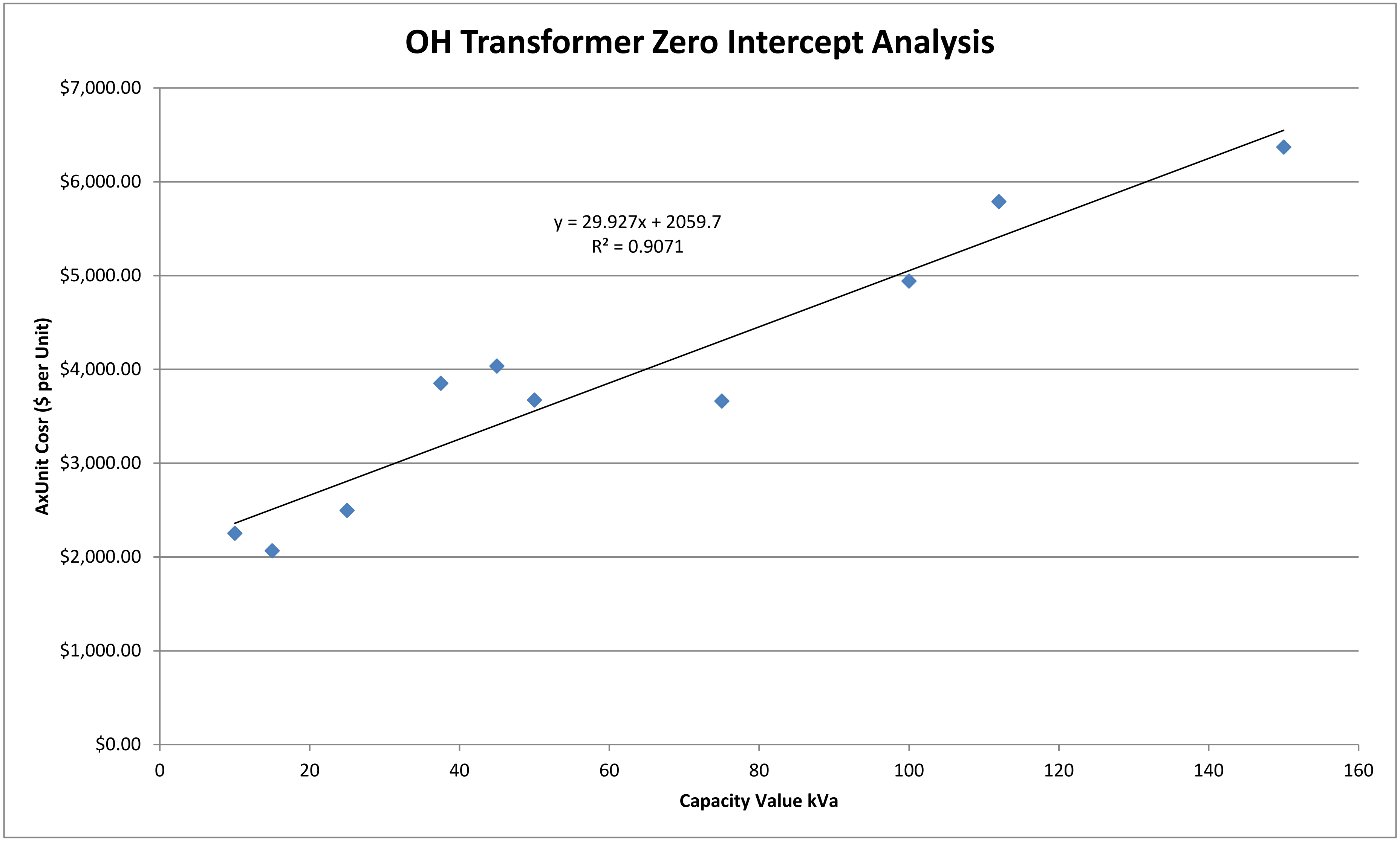
Highlighted values have been revised.



Highlighted values have been revised.



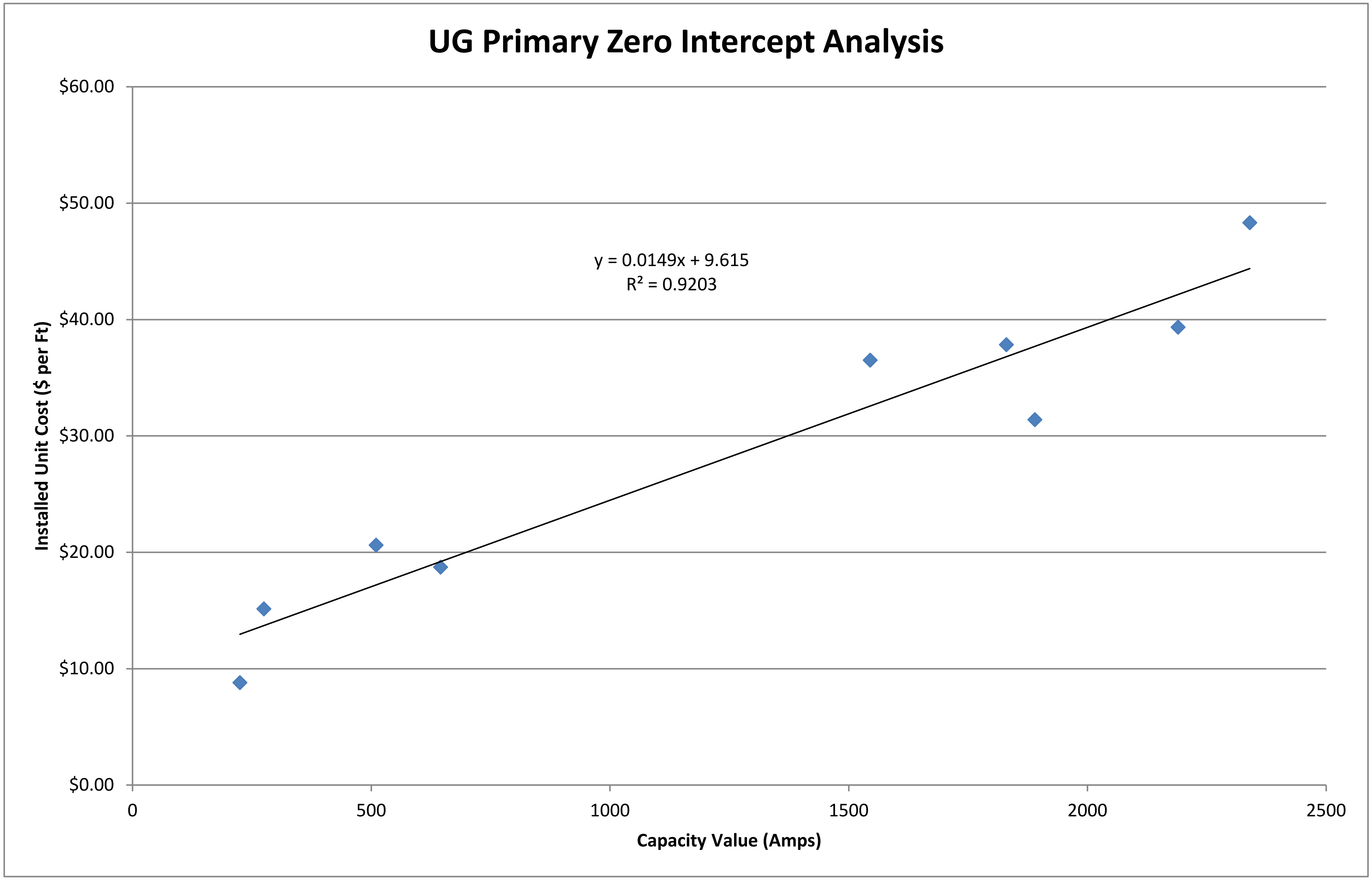
Highlighted values have been revised.



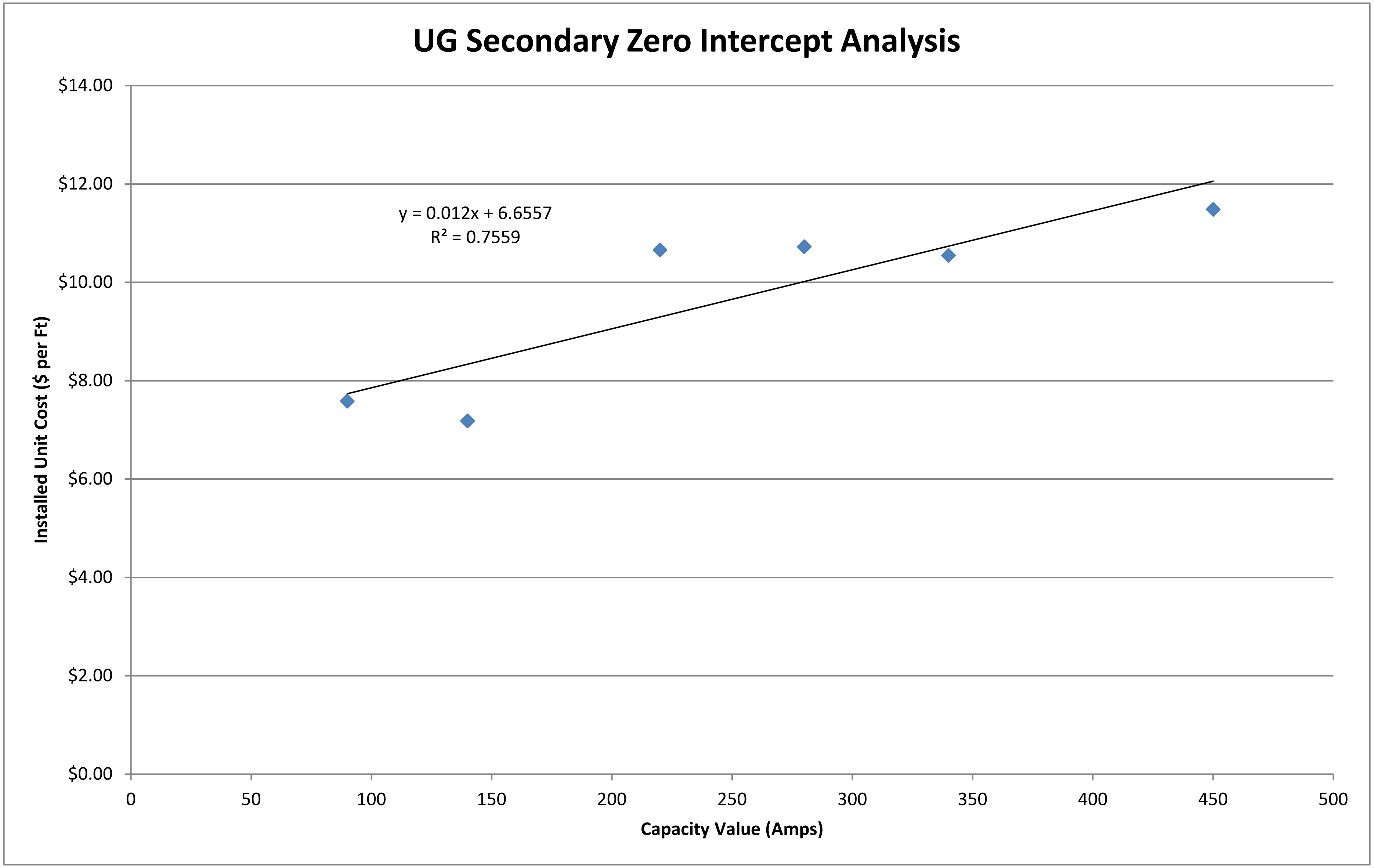
Northern States Power Company
Underground Primary Zero Intercept Analysis

Case No. PU-20-441
Exhibit___(MAP-1), **REVISED** Schedule 6
Attachment K

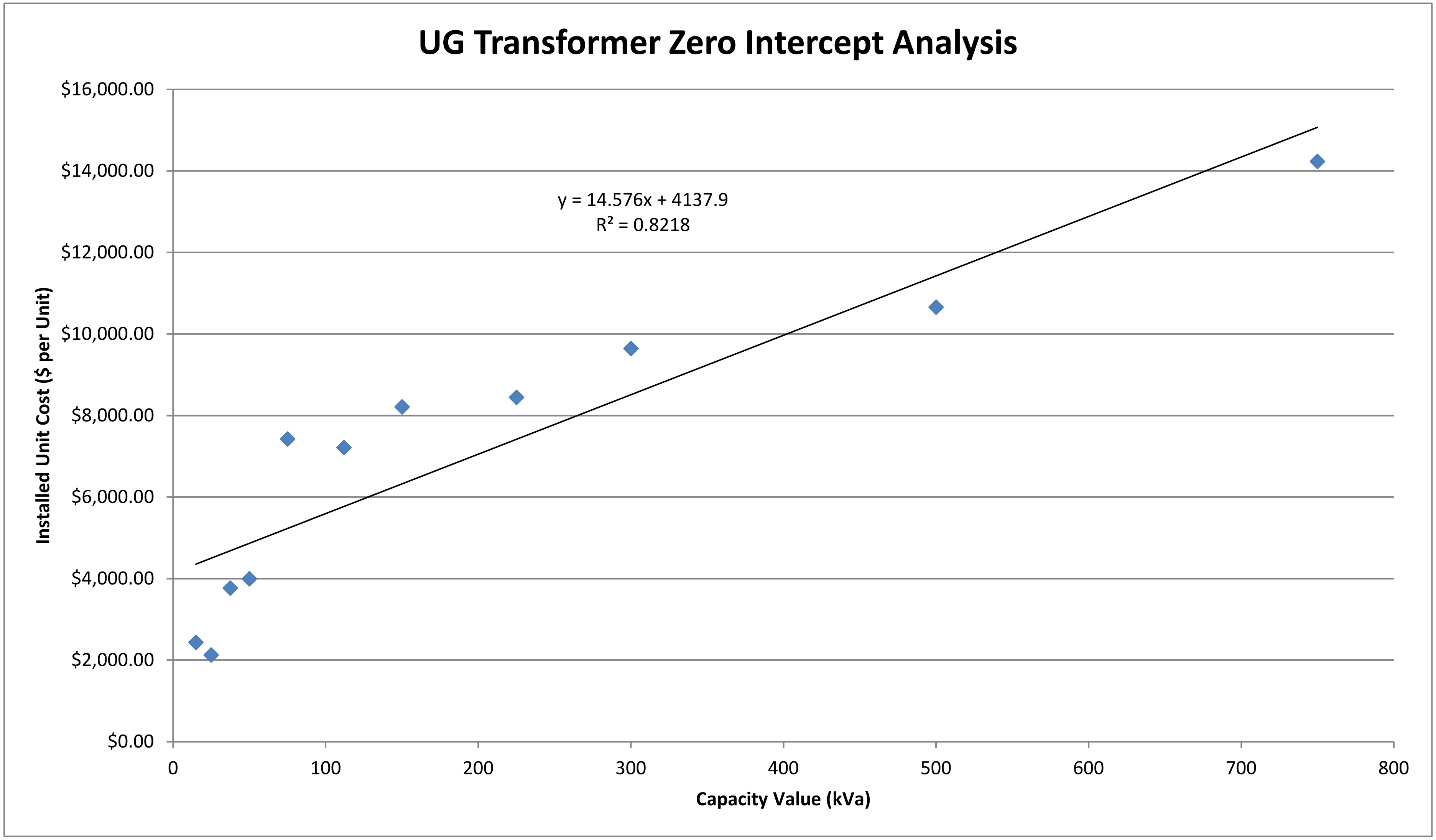
Highlighted values have been revised.



Highlighted values have been revised.



Highlighted values have been revised.



Northern States Power Company

Minimum System / Zero Intercept Distribution System Cost Analysis

Highlighted values have been revised.

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9] = [4] x [8]	[10]	[11] = [4] x [10]	[12]	[13] = [4] x [12]
Line	**Property Unit**	**Phase**	**Config Details**	**Conductor Footage/Number Transformers**	**% of Total Population Footage/ Transformers**	**Cumulative % of Total Population Footage/ Transformers**	**Load Carrying Capacity (A, or kVA)**	**Installed Unit Cost**	**Total Cost**	**Y Intercept Minimum Cost per Unit**	**Total Cost Using Y Intercept Unit Cost**	**Minimum System Cost per Unit**	**Total Cost Using Minimum System Cost per Unit**
1	OH Primary	1 ph	4 ACSR 1ph	10,859,454	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%**

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**
					Highlighted values have been revised.								
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%**

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**
					Highlighted values have been revised.								
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%**

Northern States Power Company

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**
					Highlighted values have been revised.								
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 Transforners 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

Highlighted values have been revised.

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]	[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]
1	OH Primary Single Phase Capacity						65.0850%	$6,792	15.80%
2	OH Primary Single Phase Customer						34.9150%	$3,644	8.48%
3	Total OH Primary Single Phase	40,617,685	$10.39	$421,870	25.72%	$10,435	100.00%	$10,435	
4	OH Primary Multi Phase Capacity						65.08%	$14,613	34.00%
5	OH Primary Multi Phase Customer						34.92%	$7,839	18.24%
6	Total OH Primary Multi Phase	29,585,771	$30.68	$907,682	55.34%	$22,452	100.00%	$22,452	
7	OH Secondary Capacity						21.7493%	$1,671	3.89%
8	OH Secondary Customer						78.2507%	$6,014	13.99%
9	Total OH Secondary	78,423,646	$3.96	$310,685	18.94%	$7,685	100.0000%	$7,685	
10	Street Lighting (see Line 9 of Table 3 from Michael Peppin's Direct Testimony)					$2,411		$2,411	5.61%
11	Total Overhead (see Schedule 4, Page 4, Column 1, Line 28)			$1,640,238	100.00%	$42,984		$42,984	100.00%

Line	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
		[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]
12	UG Primary Single Phase Capacity						46.81%	$13,408	17.11%
13	UG Primary Single Phase Customer						53.19%	$15,238	19.44%
14	Total UG Primary Single Phase	29,603,387	$12.23	$362,100	36.55%	$28,646	100.00%	$28,646	
15	UG Primary Multi Phase Capacity						46.81%	$19,271	24.59%
16	UG Primary Multi Phase Customer						53.19%	$21,900	27.94%
17	Total UG Primary Multi Phase	22,445,564	$23.19	$520,433	52.53%	$41,172	100.00%	$41,172	
18	UG Secondary Capacity						26.24%	$2,246	2.87%
19	UG Secondary Customer						73.76%	$6,314	8.06%
20	Total UG Secondary	11,984,490	$9.03	$108,209	10.92%	$8,560	100.00%	$8,560	
21	Street Lighting					$0		$0	0.00%
22	Total Underground			$990,742		$78,378		$78,378	100.00%

Line	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
		[1]	[2]	[3] = [1] x [2]	[4] = % of Line 27	[5] = [Col 5 Line 27] x [4]	[6] = (Customer % from Attachment N)	[7]	[8]
23	Primary	1,471	$58,201	$85,614	10.84%	$2,988	100% Capacity	$2,988	10.84%
24	Secondary Capacity						36.28%	$8,920	32.35%
25	Secondary Customer						63.72%	$15,665	56.81%
26	Total Secondary	193,554	$3,640	$704,453	89.16%	$24,585	100.00%	$24,585	89.16%
27	Total Transformers			$790,067		$27,573		$27,573	100.00%

Northern States Power Company
Minimum System Analysis for Distribution Services

Highlighted values have been revised.

	[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	40	$4.03	73,472	$11,844			
2	UG Services	1/0 Triplex	40	$2.81	13,216	$1,486			
3	Total Services				86,688	$13,329	$15,226	87.54%	12.46%

Highlighted values have been revised.

Tariff	Description	Present Price	Proposed Price	2019 Units	Present $	Proposed $	Difference
5.1.A.1	**Standard Installation and Extension Rules**						
	Excess service charge - Services	$7.90	$12.50	379	$2,994	$4,738	$1,743
	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	4	$2,400	$2,740	$340
	Per Trench Foot	$3.80	$8.90	183	$695	$1,629	$933
			REVENUE IMPACT		**$6,090**	**$9,106**	**$3,016.70**

Highlighted values have been revised.

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%

Highlighted values have been revised.

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
Propane Cost					2.02	22.5	$45.45	$45.45
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**

2019 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