

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-12-____
Exhibit____(MAP-1)

**Class Cost of Service Study
and
Selected Rate Design**

December 18, 2012

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1 I. INTRODUCTION AND QUALIFICATIONS

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Q. PLEASE STATE YOUR NAME AND TITLE.

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

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. My qualifications include more than 30 years of experience with the Company in the areas of market research and cost-of-service analysis. A detailed statement of my qualifications and experience is provided as Exhibit___(MAP-1), Schedule 1.

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

A. I present the Company's proposed Class Cost of Service Study (CCOSS) and selected items from the Company's proposed rate design. Company witness Mr. Steven V. Huso will present the remainder of the Company's proposed rate design changes.

Q. MR. PEPPIN, PLEASE LIST EACH OF THE COST OF SERVICE AND RATE DESIGN TOPICS YOU WILL ADDRESS IN YOUR TESTIMONY.

A. The topics I will address are as follows:

- Class Cost of Service Study Results
- Selected Rate Design Revisions – Voltage Discounts
- Selected changes to the Company's General Rules and Regulations

1 **II. CLASS COST OF SERVICE STUDY**

2

3 **A. Proposed Class Cost of Service Study**

4 Q. HOW DOES THE COMPANY'S PROPOSED CCOSS COMPARE WITH THAT
5 APPROVED BY THE NORTH DAKOTA PUBLIC SERVICE COMMISSION IN THE
6 COMPANY'S LAST GENERAL ELECTRIC RATE CASE, CASE NOS. PU-10-657 AND
7 11-55?

8 A. We updated the CCOSS to include 2013 test-year data, and made limited
9 adjustments, as described below. All other CCOSS process and allocation
10 methods are consistent with our previous rate case:

- 11 • Assignment of underground wiring capital costs;
- 12 • Classification and allocation of Other Production Operating and
13 Maintenance (O&M) expenses; and
- 14 • Allocation of the capacity portion of Purchased Power Agreements
15 (PPA).

16

17 Q. WHAT CHANGE HAS BEEN MADE TO THE ASSIGNMENT OF UNDERGROUND
18 WIRING CAPITAL COSTS?

19 A. A new line was added to the CCOSS to directly assign a portion of
20 underground wiring capital costs to the Street Lighting class. Previously, the
21 Company only directly assigned a portion of overhead wiring capital costs to
22 the Street Lighting class. However, in recent years, municipalities have
23 typically requested underground rather than overhead wiring. To reflect this
24 change, a Street Lighting line was added to the underground wiring detail
25 within the Original Plant In Service area of the CCOSS. All subsequent cost
26 areas within the CCOSS, such as Accumulated Depreciation and Provision for

1 Deferred Income Tax, also reflect the Street Lighting direct assignments to
2 overhead and underground wiring, although not as many detail lines are
3 shown in those areas.
4

5 Q. WHAT CHANGE HAS BEEN MADE TO THE ALLOCATION FOR OTHER
6 PRODUCTION O&M EXPENSES?

7 A. In the Company's last electric rate case, Other Production O&M costs were
8 separated into baseload and capacity subcomponents in a two-step process.
9 Under the two-step process, eight percent of these costs were treated as fixed
10 and allocated on demand. However, discussions with production plant
11 management have indicated that a higher percentage of plant operating costs
12 are fixed.
13

14 As a result, we reevaluated our process and eliminated the second separation
15 step. Our updated process to determine the proportion of fixed versus
16 variable costs splits total Other Production O&M into a Baseload sub-
17 function, based on the ratio of Original Plant Investment that has been
18 stratified as Energy- or Baseload-related (including nuclear fuel), as a percent
19 of Total Production Plant Investment.
20

21 This updated allocation process results in 25 percent of the Other Production
22 O&M costs being treated as fixed, which, according to our production plant
23 management, more accurately reflects the fixed versus variable nature of
24 Other Production O&M expenses.
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1 Q. WHAT CHANGE HAS BEEN MADE TO THE ALLOCATION OF THE CAPACITY
2 PORTION OF PURCHASED POWER AGREEMENTS?

3 A. In prior rate cases, the capacity portion of PPAs was stratified based on the
4 generation type providing the energy, similar to how the Company stratifies
5 generation plant. This was done to reflect the fact that capacity charges were
6 typically higher for PPAs from generation plants with higher capital costs and
7 lower energy costs. This stratification method would have allocated
8 approximately 73 percent of the PPA capacity costs based on demand, and the
9 remainder on energy.

10
11 However, in the current capacity market, all generation types are competing
12 based on market price, such that capacity price does not vary significantly by
13 resource type. In addition, the Company buys capacity based on its needs, not
14 the underlying resource type. Therefore, the Company proposes to allocate
15 100 percent of the capacity costs based on demand, instead of stratifying and
16 allocating the cost of the capacity according to the underlying generation type.

17
18 Q. MR. PEPPIN, HAS THE COMPANY PROVIDED ANY OTHER DOCUMENTS
19 EXPLAINING HOW ITS CCOSS IS DEVELOPED?

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

27

1 Q. PLEASE SUMMARIZE THE RESULTS OF THE PROPOSED CCOSS.
 2 A. The following table provides a summary of the CCOSS results at the class
 3 level. More information is shown on Exhibit___(MAP-1), Schedule 3. The
 4 detailed CCOSS output is shown on Exhibit___(MAP-1), Schedule 4.
 5
 6 Table 1 below shows the resulting class cost responsibilities (as opposed to
 7 proposed revenue responsibilities, which are addressed by Mr. Huso). The
 8 CCOSS results indicate what change from present rates would be needed to
 9 generate equal rates of return on investment for each class (i.e. the increase in
 10 rates necessary to produce equalized rates of return).
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Table 1
Summary of Class Cost of Service Study (\$000)

UNADJUSTED COST RESPONSIBILITIES

	Total	Resid.	Non-Demand	Demand	Street Ltg
[1] Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	199,597	75,923	12,283	109,241	2,150
[2] Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	<u>26</u>	<u>20</u>	<u>2</u>	<u>4</u>	<u>0</u>
[3] Unadjusted Operating Revenues (line 1 + line 2)	199,623	75,943	12,285	109,245	2,150
[4] Present Rates (CCOSS page 2, line 2)	<u>182,724</u>	<u>70,465</u>	<u>11,575</u>	<u>98,825</u>	<u>1,860</u>
[5] Unadjusted Deficiency (line 3 - line 4)	16,899	5,478	710	10,420	290
[6] Defic / Pres (line 5 / line 4)	9.2%	7.8%	6.1%	10.5%	15.6%
[7] Ratio: Class % / Total %	1.00	0.84	0.66	1.14	1.69

CAPACITY COST RESPONSIBILITIES FOR INTERRUPTIBLE RATE DISCOUNTS

	Total	Resid	Non-Demand	Demand	Street Ltg
[8] Interruption Rate Discounts (CCOSS page 2, line 5)	4,799	786	52	3,961	0
[9] Interruption Capacity Costs (CCOSS page 2, line 6)	<u>4,799</u>	<u>1,556</u>	<u>293</u>	<u>2,935</u>	<u>14</u>
[10] Revenue Requirement Shift (line 9 - line 8)	0	770	241	(1,025)	14

ADJUSTED COST RESPONSIBILITIES: TY 2013

	Total	Resid	Non-Demand	Demand	Street Ltg
[11] Adjusted Rate Revenue Reqt (line 1 + line 10)	199,597	76,693	12,524	108,216	2,164
[12] Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	<u>26</u>	<u>20</u>	<u>2</u>	<u>4</u>	<u>0</u>
[13] Adjusted Operating Revenues (line 11 + line 12)	199,623	76,713	12,526	108,220	2,164
[14] Present Rates (line 4)	<u>182,724</u>	<u>70,465</u>	<u>11,575</u>	<u>98,825</u>	<u>1,860</u>
[15] Adjusted Deficiency (line 13 - line 14)	16,899	6,248	951	9,395	305
[16] Defic / Pres Rates (line 15 / line 4)	9.2%	8.9%	8.2%	9.5%	16.4%
[17] Ratio: Class % / Total %	1.00	0.96	0.89	1.03	1.77

1 Table 1 replicates Exhibit____(MAP-1), Schedule 3. Schedule 3 also provides,
2 for comparison purposes, the class *revenue* allocations proposed by Mr. Huso.

3
4 Q. IN TABLE 1, YOU SHOW “ADJUSTED” AND “UNADJUSTED” COST
5 RESPONSIBILITIES. PLEASE SUMMARIZE WHAT THIS DISTINCTION MEANS.

6 A. The distinction between “adjusted” and “unadjusted” cost responsibilities
7 relates to how the “cost” of interruptible capacity is reflected in the CCOSS.
8 The method used to reflect these costs is the same as that used in the
9 Company’s last general electric rate case, Case Nos. PU-10-657 and 11-55.

10
11 Unadjusted cost responsibilities are those that were historically used as the
12 indicators of class cost responsibilities. However, as the size of the
13 Company’s interruptible programs grew, it became clear that these traditional
14 unadjusted cost responsibilities did not properly account for the fact that
15 interruptible rate discounts are essentially the “cost” of this particular source
16 of generation peaking capacity. Therefore, the Company modified the CCOSS
17 to produce adjusted cost responsibilities. The adjusted cost responsibilities
18 appropriately account for the cost of this particular source of peaking capacity.
19 Doing so is appropriate and important, because interruptible rate discounts
20 (lost revenues) are a real cost of service arising from this particular alternative
21 source of peaking capacity.

22
23 Q. PLEASE ELABORATE ON WHY INTERRUPTIBLE RATE DISCOUNTS ARE A COST OF
24 GENERATION PEAKING CAPACITY.

25 A. As the Company indicated in previous rate cases, the economic essence of a
26 utility’s “obligation to serve” is to provide low-cost reliable firm electric
27 service. Interruptible service is firm service with an after-the-fact purchased-

1 power contract provision that provides the Company the option to buy back
2 (from willing customers) all or part of their “regulatory entitlement” to firm
3 service. The resulting capacity purchase transactions occur when, and if, doing
4 so is a cost-effective source of peaking capacity, which helps the Company
5 obtain a reliable power-supply portfolio at the lowest cost. This means
6 interruptible rate discounts are essentially power-supply costs and must be
7 recognized as such in the CCOSS.

8
9 Q. HOW DID YOU RECOGNIZE THIS COST IN THE CCOSS?

10 A. To accomplish this interruptible capacity cost accounting, the Company has
11 added lines to the CCOSS model, as described below:

- 12 1. Line 8 on Table 1 above and Exhibit___(MAP-1), Schedule 3, labeled
13 “Interruption Rate Discounts,” shows the amount of the total
14 interruptible discount originating from each class.
- 15 2. Line 9 on page Table 1 above and Exhibit___(MAP-1), Schedule 3,
16 labeled “Interruption Capacity Cost,” shows how this interruptible-
17 capacity cost is allocated to the classes using the applicable generation
18 capacity cost allocation factor.
- 19 3. The resulting Line 11 on Table 1 above and Exhibit___(MAP-1), Schedule
20 3, labeled “Adjusted Rate Revenue Requirement,” shows the appropriate
21 cost of service for determining class cost responsibilities.

22
23 Q. PLEASE EXPLAIN HOW THE RESULTS OF THE COMPANY’S PROPOSED CCOSS
24 ARE USED IN DEVELOPING THE PROPOSED RATES.

25 A. The Company uses the proposed CCOSS as the basis for evaluating and
26 refining its rate structure in a rate case. Mr. Huso uses it in this case as a guide
27 in determining the proposed class revenue responsibilities, and for

1 determining the proposed rate design for each tariff. The Company's
2 proposed revenue allocation is provided on Exhibit____(MAP-1), Schedule 3,
3 lines 18 through 23.

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**III. SELECTED RATE DESIGN REVISIONS:
VOLTAGE DISCOUNTS**

Q. WHAT REVISIONS DO YOU PROPOSE TO THE VOLTAGE DISCOUNTS THAT ARE A PART OF THE C&I DEMAND TARIFFS?

A. The results of the 2013 pro forma CCOSS indicates selected changes in the demand charge discounts are warranted (as shown on Exhibit____(MAP-1), Schedule 5, page 1, lines 4 and 6) to better reflect the cost of service. Also, as shown on Exhibit____(MAP-1), Schedule 5, page 2, columns 4 and 6, increases in energy charge discounts are also appropriate in order to move rates closer to the cost of service.

Table 2 below summarizes the cost analysis provided in Exhibit____(MAP-1), Schedule 5. The table compares the pro forma 2013 costs to the present and proposed voltage discounts.

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Table 2
Voltage Discount Analysis

C&I Voltage Discounts – Demand (\$/kW)			
Rate	Primary	Transmission Transformed	Transmission
Revenue Req	\$0.52	\$1.11	\$1.58
Present	\$0.62	\$1.10	\$1.40
Midpoint	\$0.57	\$1.10	\$1.49
Proposed	\$0.60	\$1.10	\$1.50
C&I Voltage Discounts – Energy (¢/kWh)			
Rate	Primary	Transmission Transformed	Transmission
Revenue Req	0.1015¢	0.2095¢	0.2373¢
Present	0.095¢	0.200¢	0.220¢
Proposed	0.102¢	0.210¢	0.240¢

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IV. GENERAL RULES AND REGULATIONS

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Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE GENERAL RULES AND REGULATIONS IN SECTION 6 OF ITS NORTH DAKOTA ELECTRIC RATE BOOK?

8

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A. The Company is proposing one wording change to Section 3.10 ACCOUNT HISTORY CHARGE to clarify how the Company defines an “Account” for this purpose, which also matches how the Company’s cost analysis was conducted.

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There shall be a charge of \$5.00 per account as defined by unique debtor and premise numbers to the authorized requesting party for providing account history when such request involves ten or more ~~accounts~~ premises, regardless of the type of account or number of meters.

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3 **V. CONCLUSION**

4 Q. MR. PEPPIN, PLEASE PROVIDE A SUMMARY OF THE CONCLUSIONS FROM YOUR
5 TESTIMONY.

6 A. The purpose of a CCOSS is to provide a reasonable measure of the
7 contribution each class makes to the Company's overall cost of service, with
8 the ultimate goal of generating a basis from which rates can be evaluated and
9 refined. Based on the results of the CCOSS, the major customer classes have
10 the following adjusted revenue deficiencies, stated as a percentage of present
11 revenues:

- 12 • Residential Customers: 8.9 percent
- 13 • Commercial Non Demand Customers: 8.2 percent
- 14 • Commercial and Industrial Demand Billed Customers: 9.5 percent
- 15 • Lighting: 16.4 percent

16 The Company also proposes a clarifying change to its General Rules and
17 Regulations, and changes to the Demand and Energy voltage discounts to
18 move rates closer to the cost of service.

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20 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

21 A. Yes, it does.

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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-12-____

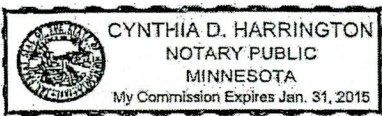
**AFFIDAVIT OF
Michael A. Peppin**

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such 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 11th day of December, 2012.

[Signature]
Notary Public



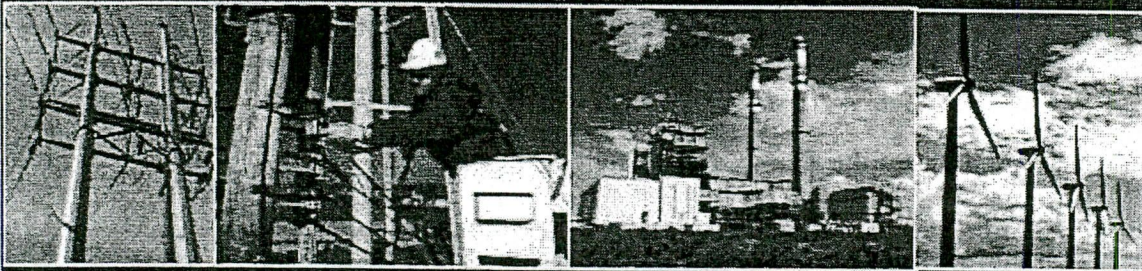
Statement of Qualifications and Experience

Michael A. Peppin

I graduated from the University of Minnesota, Twin Cities Campus, in 1978 with a Bachelor of Arts degree in Psychology, and in 1980 with a Master of Business Administration degree with an emphasis in Marketing and Statistics.

From October 1979 to December 2000, I was employed with Xcel Energy and its predecessor company Northern States Power Company ("NSP") in the positions of Principal Market Research Analyst (10 years), Market Research Manager (10 years) and Manager, Product Development Support (1½ years). In those positions, my responsibilities included conducting research to develop and evaluate NSP's Demand-Side Management programs, including NSP's interruptible and time-of-day rate programs. In January 2001, I accepted the position of Market Research Manager for Xcel Energy's unregulated broadband telecommunications subsidiary, Seren Innovations. My responsibilities involved research regarding the development, pricing and marketing of telecommunications products and services. With Xcel Energy's announced intention to sell Seren Innovations to external buyers, I accepted the position of Senior Market Research Manager with Cargill Corporation in February 2004. In that position, I conducted market research studies for many of Cargill's business units, including its Power Marketing unit. Finally, in December 2006, I resumed employment with Xcel Energy in the Pricing and Planning Department as a Principal Pricing Analyst.

My current job responsibilities include conducting Class Cost of Service Studies for various Xcel Energy jurisdictions and providing pricing function support for the utility operating subsidiaries of Xcel Energy.



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

I. Overview

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

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

II. Major Steps of the Class Cost of Service Study

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

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

III. Step 1: Functionalization

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

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

A. Generation Cost Stratification

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

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

Plant Type	\$/kW	Capacity Ratio	Capacity %	Energy %
Peaking	\$689	\$689 / \$689	100%	0%
Nuclear	\$3,678	\$689 / \$3,678	18.7%	81.3%
Fossil	\$1,912	\$689 / \$1,912	36.0%	64.0%
Combined Cycle	\$997	\$689 / \$997	69.1%	30.9%
Hydro	\$4,474	\$689 / \$4,474	15.4%	84.6%
Wind	\$15,297	\$689 / \$15,297	4.5%	95.5%

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.

B. Summer/Winter Split of Generation Capacity-Related Costs

Once the “capacity-related” portion of generation plant costs has been quantified, the costs are further separated into summer and winter sub-functions. The seasonal sub-function portions are determined as follows.

First, the 12 monthly System peak loads are grouped into a four-month summer (June, July, August and September) and an eight-month winter seasons. Second, the average hourly load for the year is subtracted from each monthly peak. Third, the remaining monthly excess loads are averaged for each season, and the ratio of these two average seasonal “excess” loads is used to assign the “capacity-related” portion of fixed generation costs to the seasons. This calculation for the current rate case is shown below.

(1)	(2)	(3)	(4) = (3) minus 5,066
Month	Season	Monthly NSP System Peak Load	Monthly Peak in Excess of Average Hourly Load
Jan	Winter	6,558	1,492
Feb	Winter	6,390	1,324
Mar	Winter	5,991	925
Apr	Winter	5,706	640
May	Winter	7,118	2,052
Jun	Summer	8,664	3,598
Jul	Summer	9,215	4,149
Aug	Summer	8,802	3,736
Sep	Summer	8,087	3,021
Oct	Winter	6,240	1,174
Nov	Winter	6,265	1,199
Dec	Winter	6,678	1,612
Average Annual Load		5,066	
Average Monthly Excess			
Average of Summer Months			3,626
Average of Winter Months			1,302
Total			4,928
Summer Percent			73.58% = 3,626/4,928
Winter Percent			26.42% = 1,302 /4,928

As shown above, 73.58% of generation capacity costs were assigned to the summer season, while 26.42% were assigned to winter, thereby separating total generation capacity-related costs into summer and winter seasons.

IV. Step 2: Cost Classification

The second step in the CCOSS process is to classify the functionalized costs as being associated with a measurable customer service requirement which gives rise to the costs. The three 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. The analysis used to separate these costs into demand and customer components is called the Minimum Distribution System (MDS) 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 table also shows the percent of each cost element that was classified as “customer” related based on the most recent Minimum System study.

Equipment Type	% Classified as “Customer” Related
Overhead Lines Primary	38.8%
Primary Transformers	0%
Overhead Lines Secondary	50.2%
Underground Lines Primary	83.0%
Underground Lines Secondary	52.5%
Line Transformers Secondary	45.6%
Services	72.7%

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

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

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

- 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 kW 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 2.

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
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 3.

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 “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 (Cus)
 - b. Demand (Dmd)
 - c. Energy (Ene)
2. Function and Associated Sub-Function:
 - a. Energy (Ene)
 - a) On-Peak Energy (On)
 - b) Off-Peak Energy (Off)
 - b. Generation (Gen_Dmd): Sub-functions include:

- a) Summer Capacity-Related Plant (Summ)
 - b) Winter Capacity-Related Plant (Wint)
 - c) Energy-Related Plant (Base)
- c. Transmission (Transco)
- d. Distribution (Disco): Sub-functions include:
- a) Distribution Substations (Psub)
 - b) Primary Voltage (Prim)
 - c) Secondary Voltage (Sec)
- e. Customer (Cus): Sub-functions include:
- a) Service Drops (Svc_Drop)
 - b) Energy Services (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 + 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:

$$\begin{aligned} &\text{Retail Revenue Requirement} = \text{Expenses (including off-setting credits from Other} \\ &\text{Operating Revenues)} \\ &\quad + \\ &\text{(Return on Equity x Rate Base) x } 1 / (1 - \text{Tax Rate)} \\ &\quad + \\ &\text{(Tax Additions - Tax Deductions) x Tax Rate} / (1 - \text{Tax Rate)} \\ &\quad + \\ &\text{AFUDC} \end{aligned}$$

Where:

$$\begin{aligned} \text{Expenses} = &\text{O\&M} + \text{Book Depreciation} + \text{Real Estate \& Property Tax} + \text{Payroll Tax} \\ &+ \text{Net Investment Tax Credit} - \text{Other Retail Revenue} - \text{Other Operating Revenue} \end{aligned}$$

$$\begin{aligned} \text{Tax Additions} = &\text{Book Depreciation} + \text{Deferred Inc Tax} + \text{Net Inv Tax Credit} \\ &+ \text{Other Misc Expenses} \end{aligned}$$

$$\text{Tax Deductions} = \text{Tax Depreciation} + \text{Interest Expense} + \text{Other Tax Timing Diff}$$

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.

$$\begin{aligned} \text{Total \$ Return} = &\text{Revenue} - \text{O\&M Expenses} - \text{Book Depreciation} \\ &- \text{Real Estate \& Property Taxes} - \text{Provision for Deferred Inc Taxes} - \text{Inv. Tax Credits} \\ &- \text{State \& Federal Income Taxes} + \text{AFUDC} \end{aligned}$$

$$\text{Percent Return on Rate Base} = \text{Total \$ Return} / \$ \text{Rate Base}$$

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.

IX. 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	1-48
	5	MINUS Accumulated Depreciation	1-30
		MINUS Accumulated Deferred Income Tax	31-59
	6	PLUS Construction Work in Progress & Other Additions	1-35
EQUALS Total Rate Base		36	
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	1-25
		MINUS Real Estate & Property Taxes	26-53
	10	MINUS Provision for Deferred Income Tax	1-28
		MINUS Investment Tax Credit	29-49
		EQUALS Present and Proposed Operating Income Before Income Taxes	51A 51B
	11 (Income Tax Calcs.)	Tax Additions	31-37
		MINUS Tax Deductions	1-30
		EQUALS Total Tax Adjustments	38
		PLUS Present and Proposed Operating Income Before Income Taxes	FROM Page 10 51A 51B
	11 (Total Return Calcs.)	EQUALS Present and Proposed Taxable Income	39A 39B
		MULTIPLIED BY State and Federal Tax Rates	
		EQUALS Present and Proposed State and Federal Income Taxes	40A 40B
		Present and Proposed Operating Income Before Income Taxes	FROM Page 10, Rows 51A & 51B
		MINUS Present and Proposed State and Federal Income Taxes	40A 40B
	11 (Total Return Calcs.)	EQUALS Present and Proposed Preliminary Return	41A 41B
		PLUS AFUDC (from page 12)	42
		EQUALS Present and Proposed Total Return	43A 43B

IX. CCOSS Output (continued)

CCOSS Section	Page Number	Results Detail	Line Numbers
Misc Calcs	12	AFUDC	1-26
		Labor Allocator	27-48
Allocator Data	13	Internal Allocators and Associated Data	1-30
	14	External Allocators and Associated Data	1-41

Appendix 1: EXTERNAL ALLOCATORS – Descriptions and Applications

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

Code	Allocator For:	Description	Allocator Rationale and 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: $C11 \times C11WAF$	Customer accounting 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: $C12 \times C12WMF$	Metering costs are driven by the number of customers in each class and the respective metering costs.
C61PS	The "customer" (minimum system) portion of primary 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 primary distribution line costs. Transmission and Transmission Transformed voltage customers are excluded since they do not use the distribution system

Appendix 1: EXTERNAL ALLOCATORS – Descriptions and Applications

Code	Allocator For:	Derivation	Allocator Rationale and 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 <u>secondary distribution line</u> costs. Transmission and primary voltage customers are excluded since they do not use the secondary distribution system.
C62NL	The “customer” (minimum system) portion of <u>service-line</u> 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 <u>service line</u> 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	<u>Distribution substation</u> 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 <u>capacity</u> portion of <u>primary</u> 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 <u>primary distribution line</u> 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 <u>capacity</u> portion of <u>secondary</u> distribution line costs	D62SecL equals the average of D62Sec percent and non-coincident (or “individual customer peak”) secondary voltage percent.	Capacity related <u>secondary distribution line</u> 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.

Appendix 1: EXTERNAL ALLOCATORS – Descriptions and Applications

Code	Allocator For:	Derivation	Allocator Rationale
D62NLL	The <u>capacity</u> portion of <u>service-line</u> 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 <u>service line costs</u> 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 <u>generation</u> 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 1.3649)) divided by (1 + 1.3649). The 1.3649 ratio is the ratio of the average summer and winter seasonal system peaks.	The driver for <u>transmission</u> costs is class contribution to the summer and 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 2.7846)) divided by (1 + 2.7846). The 2.7846 ratio is obtained from the average summer and winter season peak loads, after subtracting the average annual load from each monthly load.	Capacity- related <u>generation</u> 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.

Appendix 1: EXTERNAL ALLOCATORS – Descriptions and Applications

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.

Appendix 2: INTERNAL ALLOCATORS – Descriptions and Applications

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

Code	Allocator For:	Description	Allocator Rationale
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 number of customers, and since most assistance pertains to helping customers reduce energy use, it affects production plant investment.
D57E43	Economic development expenses	<p>This allocator is based on the weighted average of the generation capacity and energy allocators. The weighting is based on an analysis of the fixed-cost-contribution margin of the General service tariff.</p> <p>$D57E43 = (\% \text{ Demand Impacts} \times D10C) + (\% \text{ Energy Impacts} \times E8760)$.</p> <p>$\\$ \text{ Energy Impacts} = \text{kWh sales} \times (\text{Base Energy Charge} + \text{Fuel Costs} - \text{Marginal Energy Costs})$</p> <p>$\\$ \text{ Demand Impacts} = \text{Annual Billing kW} \times (((4 \times \text{Summer Demand Charge}) + (8 \times \text{Winter Demand Charge}))/12)$</p> <p>The demand portion is further split between Summer and Winter based on D10C; the energy portion is already split between on-peak and off-peak because E8760 is split that way.</p> <p>$\text{Total } \\$ \text{ Impacts} = \\$ \text{ Energy Impacts} + \\$ \text{ Demand Impacts}$</p>	Economic development program costs and benefits are assumed to be a function of the fixed cost (margin) contribution of the demand and energy charges that result from the ED program.
D40E60	CIP expenses	$D99E1 = (.99 \times D10C) + (.01 \times E8760)$.	CIP program expenses are split between capacity and energy according to whether the purpose and result of program is to reduce peak load or energy requirements. In North Dakota, 99% of program impacts are demand-related. Once program costs are thus split, the standard capacity and energy allocators are applied to the separate pools of \$ expenses.

Appendix 2: INTERNAL ALLOCATORS – Descriptions and Applications

Code	Allocator For:	Description	Allocator Rationale
LABOR	Amortizations, Payroll Taxes and A&G Expenses that are labor related such as Salaries, Pension & Benefits, Injuries & Claims	Total Labor costs on Page 12 line:48 less A&G Labor on Page 12 line 46. A&G Labor is excluded to avoid a circular reference.	The specified expenses are directly related to Labor costs.
NEPIS	Property Insurance	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 and 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 40 & 41 of page 7 and lines 12-15, 18-21, 32 and 33 of page 8). These A&G expenses are excluded to avoid circular references.	The OXTS allocator includes all O&M expenses except regulatory expense and those A&G items that are allocated with OXTS. Representing most O&M expenses, the OXTS allocator is appropriate for allocating A&G expenses.
P10	Interchange Production Capacity (i.e. fixed) inter-company Revenues. Rate base addition production-related materials and supplies	Total Production Plant: Original Plant in Service (line 6 of page 4)	Total production plant investment is closely associated with Interchange Agreement Capacity related revenues.
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 Wisconsin 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 labor costs	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.

Appendix 2: INTERNAL ALLOCATORS – Descriptions and Applications

Code	Allocator For:	Derivation	Allocator Rationale
P68	All costs related to Distribution Plant "Line Transformers"	Distribution Plant: Line Transformers Original Plant in Service (line 37 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 42 of page 4)	Street Lighting plant investment drives all Street Lighting costs.
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 26 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 50 of page 9)	Working Cash is closely related to Real Estate Taxes.
PTD	All costs related to General Plant and Electric Common Plant	Production + Transmission + Distribution Plant Original Plant Investment (lines 6, 13 and 43 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 33 of page 4)	Underground distribution line plant investment drives all costs related to Underground Distribution Lines.
RTBASE	Income Tax Addition: Avoided tax interest	Total Rate Base (line 36 of page 6)	Total rate base drives avoided tax interest.
TD	Transmission and Distribution Materials and Supplies that are Rate Base Additions	Total Transmission and Distribution Original Plant in Service (Lines 13 and 43 of page 4)	Total Transmission and distribution plant investment drives investment in miscellaneous transmission and distribution materials and supplies
ZDTS	Supervision & Engineering and Customer Installation Distribution Labor	All Distribution Labor except Supervision and Engineering and Customer Installation. These items are excluded to avoid a circular reference. (All of lines 33 thru 42 on page 12, except lines 33 and 40)	Distribution labor (excluding Supervision & Engineering) drives Supervision and Engineering and Customer Installation Labor.

Appendix 3: CCOSS Customer Classes Vs. Tariff Cross Reference

A. Summary Customer Classes

	Customer Class	Rate Codes	Voltage Specifications
1	Residential	D01, D02, D03, D04, D05 (if residential), D10 (if residential)	
2	Commercial Not Demand Metered	D05 (if C&I), D10 (if C&I), D12, D14, D15, D18, D19, D34, D40, D42	
3	C&I Secondary Voltage	D16, D17, D20, D21, D22, D41, D62, D63	Secondary
4	C&I Primary Voltage	D16, D17, D20, D21, D22, D41, D62, D63	Primary
5	Street Lighting	D11, D30, D31, D32, D33	

B. Detailed Customer Sub-Classes

	Customer Class	Rate Codes	kW Size	Voltage Specifications
1	Residential without Space Heating	D01, D02, D03, D04		
2	Residential with Space Heating	D01, D02, D03, D04		
3	Load Management	D05, D10		
4	Small Commercial Not Demand Metered	D12, D14, D15, D18, D19, D34,		
5	Small C&I Secondary Voltage	D16, D17, D62	< 1,000 kW	Secondary
6	Small C&I Primary Voltage	D16, D17, D62	< 1,000 kW	Primary
7	Large C&I Secondary Voltage	D16, D17, D62	> 1,000 kW	Secondary
8	Large C&I Primary Voltage	D16, D17, D62	> 1,000 kW	Primary
9	Interruptible All Voltages	D20, D21, D22, D63	All sizes	All Voltages
10	Municipal not Demand Metered	D40, D42		
11	Municipal Demand Metered	D41		
12	Auto Protective Lighting	D11		
13	Street Lighting – Company Owned	D30		
14	Street Lighting – Customer Owned	D31, D32, D33		

UNADJUSTED COST RESPONSIBILITIES

	<u>Total</u>	<u>Residential</u>	<u>Non-Demand</u>	<u>Demand</u>	<u>Street Ltg</u>
[1] Unadjusted Rate Revenue Req't (CCOSS page 2, line 1)	199,597	75,923	12,283	109,241	2,150
[2] Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	<u>26</u>	<u>20</u>	<u>2</u>	<u>4</u>	<u>0</u>
[3] Unadjusted Operating Revenues (line 1 + line 2)	199,623	75,943	12,285	109,245	2,150
[4] Present Rates (CCOSS page 2, line 2)	<u>182,724</u>	<u>70,465</u>	<u>11,575</u>	<u>98,825</u>	<u>1,860</u>
[5] Unadjusted Deficiency (line 3 - line 4)	16,899	5,478	710	10,420	290
[6] Defic / Pres (line 5 / line 4)	9.2%	7.8%	6.1%	10.5%	15.6%
[7] Ratio: Class % / Total %	1.00	0.84	0.66	1.14	1.69

CAPACITY COST RESPONSIBILITIES FOR INTERRUPTIBLE RATE DISCOUNTS

	<u>Total</u>	<u>Residential</u>	<u>Non-Demand</u>	<u>Demand</u>	<u>Street Ltg</u>
[8] Interruption Rate Discounts (CCOSS page 2, line 5)	4,799	786	52	3,961	0
[9] Interruption Capacity Costs (CCOSS page 2, line 6)	<u>4,799</u>	<u>1,556</u>	<u>293</u>	<u>2,935</u>	<u>14</u>
[10] Revenue Requirement Shift (line 9 - line 8)	0	770	241	(1,025)	14

ADJUSTED COST RESPONSIBILITIES

	<u>Total</u>	<u>Residential</u>	<u>Non-Demand</u>	<u>Demand</u>	<u>Street Ltg</u>
[11] Adjusted Rate Revenue Req't (line 1 + line 10)	199,597	76,693	12,524	108,216	2,164
[12] Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	<u>26</u>	<u>20</u>	<u>2</u>	<u>4</u>	<u>0</u>
[13] Adjusted Operating Revenues (line 11 + line 12)	199,623	76,713	12,526	108,220	2,164
[14] Present Rates (line 4)	<u>182,724</u>	<u>70,465</u>	<u>11,575</u>	<u>98,825</u>	<u>1,860</u>
[15] Adjusted Deficiency (line 13 - line 14)	16,899	6,248	951	9,395	305
[16] Defic / Pres Rates (line 15 / line 4)	9.2%	8.9%	8.2%	9.5%	16.4%
[17] Ratio: Class % / Total %	1.00	0.96	0.89	1.03	1.77

PROPOSED REVENUE RESPONSIBILITIES

	<u>Total</u>	<u>Residential</u>	<u>Non-Demand</u>	<u>Demand</u>	<u>Street Ltg</u>
[18] Proposed Rates (CCOSS page 3, line 3)	199,597	76,777	12,537	108,334	1,948
[19] Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	<u>26</u>	<u>20</u>	<u>2</u>	<u>4</u>	<u>0</u>
[20] Proposed Operating Revenues (line 18 + line 19)	199,623	76,797	12,539	108,338	1,948
[21] Proposed Increase (line 20 - line 14)	16,899	6,332	964	9,514	89
[22] Difference / Pres (line 21 / line 14)	9.2%	9.0%	8.3%	9.6%	4.8%
[23] Ratio: Class % / Total %	1.00	0.97	0.90	1.04	0.52

Rate Base		1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Alloc	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	Ltg
1	Plant In Service	537,079	182,835	351,311	31,299	320,012	282,259	37,753	0	0	2,932
2	Production	136,211	46,201	89,352	8,420	80,933	72,379	8,554	0	0	658
3	Transmission	138,687	86,921	47,040	9,889	37,151	34,385	2,766	0	0	4,726
4	Distribution	29,097	11,322	17,477	1,778	15,699	13,941	1,759	0	0	298
5	General	29,899	11,634	17,958	1,827	16,132	14,325	1,807	0	0	306
6	Common	11,634	4,301	6,639	675	5,964	5,296	668	0	0	113
7	Total Plant In Service	870,972	338,913	523,139	53,213	469,926	417,288	52,638	0	0	8,920
8	Production	289,499	98,849	189,025	16,820	172,204	151,752	20,452	0	0	1,625
9	Transmission	38,787	13,156	25,444	2,395	23,048	20,608	2,441	0	0	188
10	Distribution	62,947	39,210	21,019	4,418	16,601	15,374	1,227	0	0	2,718
11	General	11,053	4,301	6,639	675	5,964	5,296	668	0	0	113
12	Common	17,303	6,733	10,393	1,057	9,336	8,290	1,046	0	0	177
13	Total Depreciation Reserve	419,589	162,248	252,519	25,367	227,153	201,319	25,833	0	0	4,822
14	Net Plant In Service	451,383	176,665	270,619	27,846	242,773	215,969	26,805	0	0	4,099
15	Deducts: Accum Defer Inc Tax	92,784	37,188	54,845	5,733	49,112	43,678	5,434	0	0	750
16	Constr Work In Progress	2,037	704	1,321	121	1,200	1,063	136	0	0	12
17	Fuel Inventory	5,899	2,040	3,822	338	3,484	3,058	426	0	0	37
18	Materials & Supplies	7,613	2,756	4,800	453	4,347	3,845	502	0	0	58
19	Prepayments	6,235	2,440	3,738	385	3,353	2,983	370	0	0	57
20	Non-Plant & Work Cash	(2,735)	(1,068)	(1,633)	(172)	(1,461)	(1,298)	(163)	0	0	(34)
21	Total Additions	19,049	6,872	12,048	1,126	10,923	9,651	1,271	0	0	129
22	Rate Base	377,648	146,349	227,822	23,238	204,584	181,942	22,642	0	0	3,477
Income Statement											
22A	Tot Oper Rev - Pres	228,226	86,378	139,717	14,260	125,457	112,173	13,285	0	0	2,131
22B	Tot Oper Rev - Prop	245,125	92,710	150,195	15,224	134,971	120,704	14,266	0	0	2,220
22C	Tot Oper Rev - Equal	245,125	91,856	150,848	14,970	135,878	120,266	15,611	0	0	2,422
23	Oper & Maint	170,097	62,169	106,315	10,332	95,982	84,776	11,206	0	0	1,614
24	Book Depr + IRS Int	22,563	9,095	13,192	1,390	11,802	10,498	1,304	0	0	276
25	Payroll, RI Est & Prop Tax	9,871	3,912	5,845	615	5,230	4,656	573	0	0	114
26	Deferred Inc Tax & Net ITC	12,760	4,373	8,310	766	7,545	6,684	861	0	0	77
27A	Present Income Tax	(6,481)	(1,355)	(5,081)	(242)	(4,839)	(3,824)	(1,015)	0	0	(45)
27B	Proposed Income Tax	(1)	1,073	(1,063)	128	(1,191)	(553)	(638)	0	0	(11)
27C	Equal Income Tax	(0)	746	(813)	30	(843)	(721)	(123)	0	0	67
28	Allow Funds Dur Const	0	0	0	0	0	0	0	0	0	0
29A	Present Return	19,416	8,184	11,136	1,398	9,738	9,383	354	0	0	96
29B	Proposed Return	29,834	12,088	17,596	1,992	15,603	14,643	960	0	0	150
29C	Equal Return	29,834	11,562	17,998	1,836	16,162	14,373	1,789	0	0	275
30A	Pres Ret on Rt Base	5.14%	5.59%	4.89%	6.02%	4.76%	5.16%	1.56%	0.00%	0.00%	2.75%
30B	Prop Ret on Rt Base	7.90%	8.26%	7.72%	8.57%	7.63%	8.05%	4.24%	0.00%	0.00%	4.33%
31A	Pres Ret on Common	5.35%	6.21%	4.87%	7.01%	4.62%	5.38%	-1.46%	0.00%	0.00%	0.81%
31B	Prop Ret on Common	10.60%	11.28%	10.26%	11.88%	10.08%	10.88%	3.63%	0.00%	0.00%	3.80%

PRES vs Equal Rev Reqts		1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10	
	Alloc	MM	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	Ltg	
1	UnAdj Equal Rev Reqt @ 7.90%	199,597	75,923	121,524	12,283	109,241	96,743	12,499	0	0	2,150	
2	Present Revenue	182,724	70,465	110,400	11,575	98,825	88,653	10,172	0	0	1,860	
3	UnAdj Revenue Deficiency	16,873	5,458	11,125	708	10,416	8,090	2,326	0	0	290	
4	UnAdj Deficiency / Present	9.23%	7.75%	10.08%	6.12%	10.54%	9.13%	22.87%	0.00%	0.00%	15.61%	
5	Pres Interrupt Rate Discounts	4,799	786	4,013	52	3,961	2,829	1,132	0	0	0	
6	Pres Interrupt Capacity Costs	4,799	1,556	3,228	293	2,935	2,625	310	0	0	14	
7	Revenue Shift	0	770	(784)	241	(1,025)	(204)	(821)	0	0	14	
8	Adj Equal Rev Reqt (Rows 1+7)	199,597	76,693	120,740	12,524	108,216	96,539	11,677	0	0	2,164	
9	Adj Rev Defic vs Pres Rev (Row 2)	16,873	6,228	10,341	950	9,391	7,886	1,505	0	0	305	
10	Adj Deficiency / Adj Present	9.23%	8.84%	9.37%	8.20%	9.50%	8.90%	14.79%	0.00%	0.00%	16.38%	
Equal Customer Classification												
11	Min Sys & Service Drop	11,666	8,926	1,640	1,024	617	593	23	0	0	1,100	
12	Energy Services	5,236	4,173	1,038	619	419	413	5	0	0	25	
13	Total Customer (Cusco)	16,902	13,099	2,678	1,643	1,035	1,007	29	0	0	1,125	
14	Ave Monthly Customers	91,774	77,450	12,459	8,812	3,648	3,614	33	0	0	1,865	
15	Svc Drop Reqt	\$ / Mo / Cust	\$10.59	\$9.60	\$10.97	\$9.68	\$14.09	\$13.68	\$58.24	\$0.00	\$0.00	\$49.16
16	Ener Svcs Reqt	\$ / Mo / Cust	\$4.75	\$4.49	\$6.94	\$5.86	\$9.56	\$9.53	\$12.95	\$0.00	\$0.00	\$1.10
17	Total Reqt	\$ / Mo / Cust	\$15.35	\$14.09	\$17.91	\$15.54	\$23.65	\$23.21	\$71.20	\$0.00	\$0.00	\$50.26
Equal Energy Classification												
18	On Peak Rev Reqt	52,595	16,508	35,962	3,402	32,560	28,733	3,827	0	0	125	
19	Off Peak Rev Reqt	47,787	18,142	29,140	2,355	26,785	23,362	3,423	0	0	506	
20	Total Ener Rev Reqt	100,382	34,650	65,102	5,757	59,345	52,095	7,250	0	0	631	
21	Annual MWh Sales	2,270,721.284	784,751	1,466,635	125,788	1,340,847	1,172,103	168,745	0	0	19,336	
22	On Pk Reqt	Mills / kWh	23.162	21.036	24.520	27.045	24.283	24.514	22.679	0.000	0.000	6.470
23	Off Pk Reqt	Mills / kWh	21.045	23.118	19.868	18.719	19.976	19.931	20.288	0.000	0.000	26.150
24	Total Reqt	Mills / kWh	44.207	44.154	44.388	45.764	44.259	44.446	42.966	0.000	0.000	32.619
Equal Demand Classification												
25	Energy-Related Prod	21,788	7,464	14,196	1,260	12,936	11,384	1,552	0	0	128	
26	Capacity-Related Summer Peak Prod	23,303	6,962	16,340	1,388	14,952	13,358	1,595	0	0	0	
27	Capacity-Related Winter Peak Prod	8,366	3,289	4,982	545	4,437	3,981	456	0	0	95	
28	Total Capacity-Related Prod	31,669	10,251	21,322	1,933	19,389	17,339	2,050	0	0	95	
29	Total Production	53,457	17,716	35,518	3,193	32,326	28,723	3,603	0	0	223	
30	Transmission (Transco)	18,447	6,248	12,110	1,142	10,968	9,814	1,154	0	0	89	
31	Primary Dist Subs	3,072	1,128	1,914	169	1,745	1,537	207	0	0	29	
32	Prim Dist Lines	3,450	1,121	2,300	170	2,130	1,874	256	0	0	29	
33	Second Dist, Trans	3,887	1,961	1,903	209	1,693	1,693	0	0	0	23	
34	Total Distribution (Disco)	10,409	4,210	6,116	549	5,568	5,105	463	0	0	82	
35	Total Demand Rev Reqt	82,313	28,174	53,744	4,883	48,861	43,641	5,220	0	0	394	
36	Annual Billing kW	3,581,533	0	3,581,533	0	3,581,533	3,238,674	342,859	0	0	0	
37	Base Rev Reqt	\$ / kW	\$0.00	\$0.00	\$3.96	\$0.00	\$3.61	\$4.53	\$0.00	\$0.00	\$0.00	
38	Summer Rev Reqt	\$ / kW	\$0.00	\$0.00	\$4.56	\$0.00	\$4.17	\$4.65	\$0.00	\$0.00	\$0.00	
39	Winter Rev Reqt	\$ / kW	\$0.00	\$0.00	\$1.39	\$0.00	\$1.24	\$1.33	\$0.00	\$0.00	\$0.00	
40	Prod Rev Reqt	\$ / kW	\$0.00	\$0.00	\$9.92	\$0.00	\$9.03	\$8.87	\$0.00	\$0.00	\$0.00	
41	Tran Rev Reqt	\$ / kW	\$0.00	\$0.00	\$3.38	\$0.00	\$3.06	\$3.37	\$0.00	\$0.00	\$0.00	
42	Dist Rev Reqt	\$ / kW	\$0.00	\$1.71	\$0.00	\$1.55	\$1.58	\$1.35	\$0.00	\$0.00	\$0.00	
43	Tot Dmd Rev Reqt	\$ / kW	\$0.00	\$0.00	\$15.01	\$0.00	\$13.64	\$13.47	\$15.22	\$0.00	\$0.00	
44	Tot Dmd Rev Reqt	Mills / kWh	36.250	35.902	36.645	38.823	36.440	37.233	30.933	0.000	0.000	20.389
45	Summer Billing kW	1,257,547	0	1,257,547	0	1,257,547	1,129,313	128,234	0	0	0	
46	Winter Billing kW	2,323,986	0	2,323,986	0	2,323,986	2,109,361	214,625	0	0	0	
47	Tot Summer Reqt	\$ / kW	\$0.00	\$0.00	\$22.05	\$0.00	\$20.12	\$19.95	\$0.00	\$0.00	\$0.00	
48	Tot Winter Reqt	\$ / kW	\$0.00	\$0.00	\$11.20	\$0.00	\$10.14	\$10.01	\$11.37	\$0.00	\$0.00	
49	Energy + Production (Genco)	153,839	52,366	100,620	8,949	91,671	80,818	10,853	0	0	854	

PROP vs Equal Rev Reqts		1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Alloc	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	Ltq
1	Total Retail Rev Req	7.90%	8.26%	7.72%	8.57%	7.63%	8.05%	4.24%	0.00%	0.00%	4.33%
	Proposed Ret On Rt Base										
2	UnAdj Equalized Rev Req	199,597	75,923	121,524	12,283	109,241	96,743	12,499	0	0	2,150
3	Proposed Revenue	199,597	76,777	120,872	12,537	108,334	97,181	11,154	0	0	1,948
4	UnAdj Revenue Deficiency	0	(854)	653	(254)	907	(438)	1,345	0	0	202
5	UnAdj Deficiency / Proposed	0.00%	-1.11%	0.54%	-2.03%	0.84%	-0.45%	12.06%	0%	0%	10.35%
6	Prop Interrupt Rate Discounts	4,972	844	4,128	51	4,077	2,927	1,150	0	0	0
7	Prop Interrupt Capacity Costs	4,972	1,612	3,345	304	3,041	2,720	322	0	0	15
8	Revenue Shift	0	770	(784)	241	(1,025)	(204)	(821)	0	0	14
9	Adj Equal Rev (Rows 2+8)	199,597	76,693	120,740	12,524	108,216	96,539	11,677	0	0	2,164
10	Adj Rev Defic vs Prop Rev (Row 3)	0	(84)	(131)	(13)	(118)	(642)	523	0	0	216
11	Adj Deficiency / Adj Prop	0.00%	-0.11%	-0.11%	-0.10%	-0.11%	-0.66%	4.69%	0.00%	0.00%	11.09%
Prop Customer Component											
12	Min Sys & Service Drop	11,766	9,086	1,674	1,057	617	597	20	0	0	1,006
13	Energy Services	5,236	4,173	1,038	619	419	413	5	0	0	25
14	Total Customer (Cusco)	17,002	13,259	2,712	1,676	1,036	1,011	26	0	0	1,031
15	Ave Monthly Customers	91,774	77,450	12,459	8,812	3,648	3,614	33	0	0	1,865
16	Svc Drop Req	\$ / Mo / Cust	\$10.68	\$9.78	\$11.20	\$9.99	\$14.11	\$50.84	\$0.00	\$0.00	\$44.95
17	Ener Svcs Req	\$ / Mo / Cust	\$4.75	\$4.49	\$6.94	\$5.86	\$9.56	\$12.96	\$0.00	\$0.00	\$1.10
18	Total Req	\$ / Mo / Cust	\$15.44	\$14.27	\$18.14	\$15.85	\$23.67	\$63.80	\$0.00	\$0.00	\$46.05
Prop Energy Component											
19	On Peak Rev Req	52,594	16,514	35,955	3,404	32,551	28,737	3,814	0	0	125
20	Off Peak Rev Req	47,784	18,147	29,133	2,356	26,777	23,365	3,412	0	0	504
21	Total Ener Rev Req	100,378	34,661	65,088	5,760	59,328	52,102	7,227	0	0	629
22	Annual MWh Sales	2,270,721	784,751	1,466,635	125,788	1,340,847	1,172,103	168,745	0	0	19,336
23	On Pk Req	Mills / kWh	23.162	21.043	24.516	27.062	24.277	24.517	0.000	0.000	6.449
24	Off Pk Req	Mills / kWh	21.044	23.125	19.864	18.730	19.970	20.221	0.000	0.000	26.066
25	Total Req	Mills / kWh	44.205	44.168	44.379	45.792	44.247	44.451	0.000	0.000	32.515
Prop Demand Component											
26	Energy-Related Prod	21,671	7,777	13,823	1,357	12,466	11,577	889	0	0	71
27	Capacity-Related Summer Peak Prod	23,288	7,053	16,235	1,422	14,814	13,429	1,385	0	0	0
28	Capacity-Related Winter Peak Prod	8,371	3,332	4,956	558	4,398	4,002	396	0	0	83
29	Total Capacity-Related Prod	31,659	10,384	21,192	1,980	19,212	17,431	1,781	0	0	83
30	Total Production	53,330	18,161	35,015	3,337	31,678	29,009	2,669	0	0	155
31	Transmission (Transco)	18,442	6,414	11,963	1,199	10,764	9,921	843	0	0	66
32	Primary Dist Subs	3,066	1,148	1,893	175	1,718	1,549	170	0	0	24
33	Prim Dist Lines	3,440	1,137	2,278	175	2,104	1,885	219	0	0	25
34	Second Dist, Trans	3,938	1,997	1,922	216	1,706	1,706	0	0	0	19
35	Total Distribution (Disco)	10,445	4,282	6,094	566	5,528	5,139	389	0	0	69
36	Total Demand Rev Req	82,217	28,857	53,071	5,101	47,970	44,068	3,902	0	0	289
37	Annual Billing kW	3,581,533	0	3,581,533	0	3,581,533	3,238,674	342,859	0	0	0
38	Base Rev Req	\$ / kW	\$0.00	\$0.00	\$0.00	\$3.48	\$3.57	\$2.59	\$0.00	\$0.00	\$0.00
39	Summer Rev Req	\$ / kW	\$0.00	\$0.00	\$0.00	\$4.14	\$4.15	\$4.04	\$0.00	\$0.00	\$0.00
40	Winter Rev Req	\$ / kW	\$0.00	\$0.00	\$0.00	\$1.23	\$1.24	\$1.15	\$0.00	\$0.00	\$0.00
41	Prod Rev Req	\$ / kW	\$0.00	\$0.00	\$0.00	\$8.84	\$8.84	\$7.79	\$0.00	\$0.00	\$0.00
42	Tran Rev Req	\$ / kW	\$0.00	\$0.00	\$0.00	\$3.01	\$3.06	\$2.46	\$0.00	\$0.00	\$0.00
43	Dist Rev Req	\$ / kW	\$0.00	\$0.00	\$0.00	\$1.54	\$1.59	\$1.13	\$0.00	\$0.00	\$0.00
44	Tot Dmd Rev Req	\$ / kW	\$0.00	\$0.00	\$0.00	\$13.39	\$13.61	\$11.38	\$0.00	\$0.00	\$0.00
45	Tot Dmd Rev Req	Mills / kWh	36.207	36.772	36.186	40.554	35.776	37.598	0.000	0.000	14.941
46	Summer Billing kW	1,257,547	0	1,257,547	0	1,257,547	1,129,313	128,234	0	0	0
47	Winter Billing kW	2,323,986	0	2,323,986	0	2,323,986	2,109,361	214,625	0	0	0
48	Tot Summer Req	\$ / kW	\$0.00	\$0.00	\$21.81	\$0.00	\$19.81	\$20.12	\$0.00	\$0.00	\$0.00
49	Tot Winter Req	\$ / kW	\$0.00	\$0.00	\$11.03	\$0.00	\$9.92	\$10.12	\$0.00	\$0.00	\$0.00
50	Energy + Production (Genco)	153,708	52,822	100,103	9,097	91,006	81,110	9,896	0	0	783
51	Prop Rev - Pres Rev (Pg 2)	16,873	6,312	10,472	963	9,509	8,528	981	0	0	89
52	Difference / Present	9.23%	8.96%	9.49%	8.32%	9.62%	9.62%	9.65%	0.00%	0.00%	4.77%

Original Plant in Service			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	Alloc	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	Ltg
1	Summer Peak	D10S	98,517	29,487	69,030	5,869	63,161	56,424	6,736	0	0	0
2	Winter Peak	D10W	35,379	13,929	21,047	2,304	18,742	16,817	1,925	0	0	403
3	Total Peak	D10C	133,896	43,416	90,077	8,174	81,903	73,241	8,662	0	0	403
4	Base Load	E8760	281,170	97,227	182,179	16,127	166,051	145,764	20,287	0	0	1,764
5	Nuclear Fuel	E8760	122,013	42,191	79,056	6,998	72,057	63,254	8,804	0	0	765
6	Total	32.26%	537,079	182,835	351,311	31,299	320,012	282,259	37,753	0	0	2,932
Transmission												
7	Gen Step Up Base	E8760	2,969	1,027	1,924	170	1,753	1,539	214	0	0	19
8	Gen Step Up Peak	D10C	1,414	458	951	86	865	773	91	0	0	4
9	Total Gen Step Up		4,383	1,485	2,875	257	2,618	2,313	306	0	0	23
10	Bulk Transmission	D10T	131,815	44,715	86,464	8,163	78,301	70,066	8,235	0	0	635
11	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign	13	0	13	0	13	0	13	0	0	0
13	Total		136,211	46,201	89,352	8,420	80,933	72,379	8,554	0	0	658
Distribution Substations												
14	General Step Up	STRATH	213	73	139	12	126	111	15	0	0	1
15	Bulk Transmission	D10T	108	37	71	7	64	57	7	0	0	1
16	Distrib Function	D60Sub	19,747	7,264	12,294	1,090	11,204	9,873	1,331	0	0	189
17	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
18	Total		20,068	7,373	12,504	1,109	11,395	10,042	1,353	0	0	191
Overhead Lines												
19	Primary Capacity	D61PS	11,848	3,856	7,891	584	7,307	6,430	878	0	0	100
20	Primary Customer	C61PS	7,510	6,462	1,038	732	306	303	3	0	0	11
21	Total Primary		19,358	10,318	8,929	1,316	7,613	6,733	880	0	0	111
22	Second Capacity	D62SecL	4,713	2,233	2,449	266	2,183	2,183	0	0	0	31
23	Second Customer	C62Sec	4,757	4,095	656	464	192	192	0	0	0	7
24	Total Secondary		9,470	6,327	3,105	730	2,375	2,375	0	0	0	38
25	Street Lighting	DASL	1,067	0	0	0	0	0	0	0	0	1,067
26	Total		29,895	16,645	12,033	2,045	9,988	9,108	880	0	0	1,216
Underground Lines												
27	Primary Capacity	D61PS	4,831	1,572	3,218	238	2,979	2,622	358	0	0	41
28	Primary Customer	C61PS	23,616	20,320	3,263	2,301	962	953	9	0	0	34
29	Total Primary		28,447	21,892	6,480	2,539	3,941	3,575	367	0	0	75
30	Second Capacity	D62SecL	11,627	5,508	6,042	656	5,386	5,386	0	0	0	77
31	Second Customer	C62Sec	12,842	11,054	1,770	1,252	518	518	0	0	0	18
32	Total Secondary		24,469	16,561	7,812	1,908	5,904	5,904	0	0	0	96
33	Street Lighting	DASL	1,067	0	0	0	0	0	0	0	0	1,067
	Total		53,983	38,453	14,292	4,447	9,845	9,479	367	0	0	1,237
Line Transformers												
34	Primary	D61PS	711	231	474	35	438	386	53	0	0	6
35	Second Capacity	D62SecL	6,803	3,223	3,535	384	3,151	3,151	0	0	0	45
36	Second Customer	C62Sec	5,699	4,905	786	555	230	230	0	0	0	8
37	Total		13,213	8,359	4,794	974	3,820	3,767	53	0	0	59
Services												
38	Second Capacity	D62NLL	3,719	3,012	707	106	602	602	0	0	0	0
39	Second Customer	C62NL	9,880	9,356	524	371	154	154	0	0	0	0
40	Total		13,599	12,367	1,232	476	756	756	0	0	0	0
41	Meters	C12WM	6,008	3,722	2,184	837	1,347	1,234	113	0	0	101
42	Street Lighting	Dir Assign	1,921	0	0	0	0	0	0	0	0	1,921
43	Total Distribution		138,687	86,921	47,040	9,889	37,151	34,385	2,766	0	0	4,726
44	General Plant	PTD	29,097	11,322	17,477	1,778	15,699	13,941	1,759	0	0	298
45	Electric Common	PTD	29,899	11,634	17,958	1,827	16,132	14,325	1,807	0	0	306
46	Prelim Elec Plant		870,972	338,913	523,139	53,213	469,926	417,288	52,638	0	0	8,920
47	TBT Investment	NEPIS	0	0	0	0	0	0	0	0	0	0
48	Elec Plant in Serv		870,972	338,913	523,139	53,213	469,926	417,288	52,638	0	0	8,920

Accum Deprec; Net Plant		1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Alloc	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	Ltg
Production											
1	Peaking Plant	D10C	58,423	18,944	39,303	3,567	35,737	31,957	3,779	0	176
2	Decom Int Peaking	D10C	0	0	0	0	0	0	0	0	0
3	Decom Int Baseload	E8760	0	0	0	0	0	0	0	0	0
4	Nuclear Fuel	E8760	108,511	37,523	70,308	6,224	64,084	56,254	7,829	0	681
5	Base Load	E8760	122,565	42,383	79,414	7,030	72,384	63,540	8,844	0	769
6	Total		289,499	98,849	189,025	16,820	172,204	151,752	20,452	0	1,625
Transmission											
7	Gen Step Up Base	E8760	1,281	443	830	73	757	664	92	0	8
8	Gen Step Up Peak	D10C	610	198	410	37	373	334	39	0	2
9	Total Gen Step Up		1,891	641	1,240	111	1,130	998	132	0	10
10	Bulk Transmission	D10T	36,892	12,515	24,199	2,285	21,915	19,610	2,305	0	178
11	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0
12	Direct Assgn	Dir Assgn	4	0	4	0	4	4	0	0	0
13	Total		38,787	13,156	25,444	2,395	23,048	20,608	2,441	0	188
Distribution											
14	General Step Up	STRATH	109	37	71	6	65	57	8	0	1
15	Bulk Transmission	D10T	44	15	29	3	26	23	3	0	0
16	Distrib Function	D60Sub	9,032	3,322	5,623	498	5,125	4,516	609	0	87
17	Direct Assgn	Dir Assgn	0	0	0	0	0	0	0	0	0
18	Total Substations		9,185	3,375	5,723	507	5,216	4,596	619	0	87
19	Overhead Lines	POL	12,465	6,940	5,017	853	4,165	3,798	367	0	507
20	Underground	PUL	22,523	16,044	5,963	1,855	4,108	3,955	153	0	516
21	Line Transformers	P68	6,945	4,394	2,520	512	2,008	1,980	28	0	31
22	Services	P69	7,148	6,501	647	250	397	0	0	0	0
23	Meters	C12WM	3,158	1,957	1,148	440	708	649	59	0	53
24	Street Lighting	P73	1,523	0	0	0	0	0	0	0	1,523
25	Total		62,947	39,210	21,019	4,418	16,601	15,374	1,227	0	2,718
26	General Plant	PTD	11,053	4,301	6,639	675	5,964	5,296	668	0	113
27	Electric Common	PTD	17,303	6,733	10,393	1,057	9,336	8,290	1,046	0	177
28	Total Accum Depr		419,589	162,248	252,519	25,367	227,153	201,319	25,833	0	4,822
29	Net Elec Plant		451,383	176,665	270,619	27,846	242,773	215,969	26,805	0	4,099
30	Net Plant w/ TBT		451,383	176,665	270,619	27,846	242,773	215,969	26,805	0	4,099
Subtractions: Accum Defer Inc Tax											
Production											
31	Peaking Plant	D10C	16,036	5,200	10,788	979	9,809	8,772	1,037	0	48
32	Base Load	E8760	45,257	15,650	29,324	2,596	26,728	23,462	3,265	0	284
33	Nuclear Fuel	E8760	1,876	649	1,215	108	1,108	972	135	0	12
34	Total		63,169	21,498	41,327	3,682	37,645	33,206	4,438	0	344
Transmission											
35	Gen Step Up Base	E8760	639	221	414	37	377	331	46	0	4
36	Gen Step Up Peak	D10C	304	99	205	19	186	166	20	0	1
37	Total Gen Step Up		943	320	619	55	563	498	66	0	5
38	Bulk Transmission	D10T	22,164	7,519	14,539	1,373	13,166	11,781	1,385	0	107
39	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0
40	Direct Assgn	Dir Assgn	3	0	3	0	3	0	0	0	0
41	Total		23,110	7,838	15,160	1,428	13,732	12,279	1,453	0	112
Distribution											
42	General Step Up	STRATH	42	14	27	2	25	22	3	0	0
43	Bulk Transmission	D10T	16	5	10	1	10	9	1	0	0
44	Distrib Function	D60Sub	2,613	961	1,627	144	1,483	1,306	176	0	25
45	Direct Assgn	Dir Assgn	0	0	0	0	0	0	0	0	0
46	Total Substations		2,671	981	1,665	148	1,517	1,337	180	0	25
47	Overhead Lines	POL	5,139	2,861	2,069	352	1,717	1,566	151	0	209
48	Underground	PUL	8,478	6,039	2,245	698	1,546	1,489	58	0	194
49	Line Transformers	P68	1,943	1,229	705	143	562	554	8	0	9
50	Services	P69	2,181	1,983	198	76	121	121	0	0	0
51	Meters	C12WM	870	539	316	121	195	179	16	0	15
52	Street Lighting	P73	(26)	0	0	0	0	0	0	0	(26)
53	Total		21,256	13,633	7,197	1,539	5,658	5,245	413	0	426
54	General Plant	PTD	3,848	1,497	2,311	235	2,076	1,844	233	0	39
55	Electric Common	PTD	2,264	881	1,360	138	1,222	1,085	137	0	23
56	Total Deferred Tax		113,647	45,348	67,355	7,022	60,333	53,659	6,674	0	944
57	Net Operating Loss (NOL) Carry Forward	NEPIS	(19,784)	(7,743)	(11,861)	(1,220)	(10,641)	(9,466)	(1,175)	0	(180)
58	Non-Plant Related	LABOR	(1,079)	(417)	(648)	(68)	(580)	(514)	(66)	0	(14)
59	Accum Def W/ Adj		92,784	37,188	54,845	5,733	49,112	43,678	5,434	0	750

Additions: CWIP, Etc; Rate Base		1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Alloc	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	Ltg
Production											
1	Peaking Plant	D10C	193	63	130	12	118	106	12	0	1
2	Base Load	E8760	750	259	486	43	443	389	54	0	5
3	Nuclear Fuel	E8760	219	76	142	13	129	114	16	0	1
4	Total		1,162	398	758	67	690	608	82	0	7
Transmission											
5	Gen Step Up Base	E8760	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10C	0	0	0	0	0	0	0	0	0
7	Total Gen Step Up		0	0	0	0	0	0	0	0	0
8	Bulk Transmission	D10T	723	245	474	45	429	384	45	0	3
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0
11	Total		723	245	474	45	429	384	45	0	3
Distribution											
12	General Step Up	STRATH	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub	6	2	4	0	3	3	0	0	0
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0
16	Total Substations		6	2	4	0	3	3	0	0	0
17	Overhead Lines	POL	3	2	1	0	1	1	0	0	0
18	Underground	PUL	4	3	1	0	1	1	0	0	0
19	Line Transformers	P68	0	0	0	0	0	0	0	0	0
20	Services	P69	0	0	0	0	0	0	0	0	0
21	Meters	C12VMM	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73	0	0	0	0	0	0	0	0	0
23	Total		13	7	6	1	5	5	1	0	0
24	General Plant	PTD	93	36	56	6	50	45	6	0	1
25	Electric Common	PTD	46	18	28	3	25	22	3	0	0
26	Total CWIP		2,037	704	1,321	121	1,200	1,063	136	0	12
27	Fuel Inventory	E8760	5,899	2,040	3,822	338	3,484	3,058	426	0	37
Materials & Supplies											
28	Production	P10	6,473	2,204	4,234	377	3,857	3,402	455	0	35
29	Trans & Distr	ID	1,140	552	566	76	490	443	47	0	22
30	Total		7,613	2,756	4,800	453	4,347	3,845	502	0	58
Prepayments											
31	Miscellaneous	NEPIS	6,235	2,440	3,738	385	3,353	2,983	370	0	57
32	Total		6,235	2,440	3,738	385	3,353	2,983	370	0	57
33	Non-Plant Assets & Liab	LABOR	(1,809)	(698)	(1,087)	(115)	(972)	(862)	(110)	0	(24)
34	Working Cash	PTO	(926)	(369)	(546)	(58)	(489)	(436)	(53)	0	(10)
35	Total Additions		19,049	6,872	12,048	1,126	10,923	9,651	1,271	0	129
36	Total Rate Base		377,648	146,349	227,822	23,238	204,584	181,942	22,642	0	3,477
37	Common Rate Base (@ 52.56%)		198,491.8	76,921	119,743	12,214	107,529	95,629	11,901	0	1,828

Operating Rev (Cal Month)			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
		Alloc	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	Ltg
1	Retail Revenue		182,724	70,465	110,400	11,575	98,825	88,653	10,172	0	0	1,860
2	Present Rate Revenue	R01; (calc)	182,724	70,465	110,400	11,575	98,825	88,653	10,172	0	0	1,860
3	Proposed Rate Revenue	PROREV; (ca	199,597	76,777	120,872	12,537	108,334	97,181	11,154	0	0	1,948
3	Equal Rate Revenue		199,597	75,923	121,524	12,283	109,241	96,743	12,499	0	0	2,150
Other Retail Revenue												
4	Interdepartmental	R01; R02	0	0	0	0	0	0	0	0	0	0
5	Gross Earnings Tax	R01; R02	0	0	0	0	0	0	0	0	0	0
6	CIP Adjustment to Program Costs	D99E1	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	11,897	4,050	7,782	693	7,089	6,252	836	0	0	65
9	Interchg Prod Energy	E8760	13,089	4,526	8,481	751	7,730	6,786	944	0	0	82
10	Interchg Tr Bulk Supply	D10T	2,629	892	1,725	163	1,562	1,397	164	0	0	13
11	Dist Int Sales; Oth Serv	E8760	0	0	0	0	0	0	0	0	0	0
12	Dist Overhd Line Rent	POL	268	149	108	18	90	82	8	0	0	11
13	Connection Charges	C11	274	231	37	26	11	11	0	0	0	6
14	Sales For Resale	E8760	9,115	3,152	5,906	523	5,383	4,725	658	0	0	57
15	Joint Op Agree-Other PSCo Rev	D10T	(370)	(126)	(243)	(23)	(220)	(197)	(23)	0	0	(2)
16	Misc Ancillary Trans Rev	D10T	8,127	2,757	5,331	503	4,828	4,320	508	0	0	39
17	MISO	D10T	100	34	66	6	59	53	6	0	0	0
18	Other	D10T	95	32	62	6	56	50	6	0	0	0
19	Late Pay Chg - Pres	R16C; R02	278,000	215	63	18	45	40	5	0	0	0
20	Tot Other Op - Pres		45,502	15,913	29,317	2,685	26,632	23,520	3,112	0	0	272
21	Incr Misc Serv - Prop	R01,	0	0	0	0	0	0	0	0	0	0
22	Incr Inter-Dep'l - Prop	R01; R02	0	0	0	0	0	0	0	0	0	0
23	Incr Late Pay - Prop	(R16C); R02	26	20	6	2	4	4	0	0	0	0
24	Tot Other Op - Prop		45,528	15,933	29,323	2,687	26,636	23,524	3,113	0	0	272
25	Tot Oper Rev - Pres		228,226	86,378	139,717	14,260	125,457	112,173	13,285	0	0	2,131
26	Tot Oper Rev - Prop		245,125	92,710	150,195	15,224	134,971	120,704	14,266	0	0	2,220
	Tot Oper Rev - Eql		245,125	91,856	150,848	14,970	135,878	120,266	15,611	0	0	2,422
Operating & Maint (Pg 1 of 2)												
Production Expen												
27	Fuel	E8760	38,194	13,207	24,747	2,191	22,556	19,801	2,756	0	0	240
Purchased Power												
28	Purchases: Cap Peak	D10C	7,397	2,399	4,976	452	4,525	4,046	479	0	0	22
29	Purchases: Cap Base	D10C	2,752	892	1,851	168	1,683	1,505	178	0	0	8
30	Purchases: Demand		10,149	3,291	6,828	620	6,208	5,552	657	0	0	31
31	Purchases: Other Energy	E8760	43,438	15,021	28,145	2,492	25,653	22,519	3,134	0	0	273
32	Tot Non-Assoc Purch		53,587	18,312	34,972	3,111	31,861	28,071	3,791	0	0	303
33	Interchg Agr Capacity	P10WoN	2,897	982	1,900	170	1,731	1,529	202	0	0	15
34	Interchg Agr Energy	E8760	1,339	463	868	77	791	694	97	0	0	8
35	Tot Wis Interchg Purch		4,236	1,445	2,768	246	2,521	2,223	299	0	0	24
36	Tot Purchased Power		57,823	19,756	37,740	3,357	34,383	30,293	4,089	0	0	327
Other Production												
37	Capacity Related	D10C	8,271	2,682	5,564	505	5,059	4,524	535	0	0	25
38	Energy Related	E8760	24,904	8,612	16,136	1,428	14,708	12,911	1,797	0	0	156
39	Total Other Product		33,175	11,294	21,700	1,933	19,767	17,435	2,332	0	0	181
40	Total Production		129,192	44,257	84,188	7,482	76,706	67,529	9,177	0	0	747
41	Transmission Exp	D10T	14,031	4,760	9,204	869	8,335	7,458	877	0	0	68

Operating & Maint (Pg 2 of 2)			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Alloc	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	Ltg	
1	Distribution Expen	ZDTS	770	404	319	56	263	240	24	0	0	47
2	Supervision & Engr'g	D10T	240	81	157	15	143	128	15	0	0	1
3	Load Dispatching	P61	522	192	325	29	296	261	35	0	0	5
4	Substations	POL	2,399	1,336	966	164	802	731	71	0	0	98
5	Overhead Lines	PUL	1,286	916	340	106	235	226	9	0	0	29
6	Underground Lines	P6B	2	1	1	0	1	1	0	0	0	0
7	Line Transformers	C12WM	242	150	88	34	54	50	5	0	0	4
8	Meters	OXDTS	177	95	66	12	54	49	5	0	0	16
9	Customer Install'n	Dir Assign	328	0	0	0	0	0	0	0	0	328
10	Street Lighting	OXDTS	571	305	214	40	175	159	15	0	0	52
11	Miscellaneous	POL	226	126	91	15	76	69	7	0	0	9
12	Rents (Pole Attachmts)		6,763	3,606	2,568	471	2,098	1,913	184	0	0	589
12	Total Distribution											
13	Customer Accounting	C11WA	4,286	3,406	863	512	351	347	4	0	0	16
14	Sales, Econ Dvlp & Other	D57E43	173	58	115	10	104	93	12	0	0	1
	Admin & General											
15	Salaries	LABOR	3,332	1,286	2,002	211	1,791	1,588	202	0	0	44
16	Office Supplies	OXTS	3,004	1,098	1,878	182	1,695	1,497	198	0	0	28
17	Admin Transfer Credit	OXTS	(1,507)	(551)	(942)	(92)	(850)	(751)	(99)	0	0	(14)
18	Outside Services	LABOR	917	354	551	58	493	437	56	0	0	12
19	Property Insurance	NEPIS	726	284	435	45	390	347	43	0	0	7
20	Pensions & Benefits	LABOR	5,843	2,255	3,510	370	3,140	2,785	355	0	0	77
21	Injuries & Claims	LABOR	1,071	413	643	68	576	511	65	0	0	14
22	Regulatory Exp	R01; R02	105	40	63	7	57	51	6	0	0	1
23	General Advertising	OXTS	86	31	54	5	49	43	6	0	0	1
24	Contributions	OXTS	0	0	0	0	0	0	0	0	0	0
25	Misc General Exp	OXTS	(99)	(36)	(62)	(6)	(56)	(49)	(7)	0	0	(1)
26	Rents	OXTS	1,316	481	823	80	743	656	87	0	0	12
27	Maint of General Plan	OXTS	28	10	18	2	16	14	2	0	0	0
28	Total		14,822	5,667	8,973	930	8,043	7,129	913	0	0	182
	Cust Service & Info											
29	Cust Assist Exp - Non-CIP	C11P10	320	189	126	25	102	90	11	0	0	4
30	CIP Total	D99E1	0	0	0	0	0	0	0	0	0	0
31	Instructional Advertising	C11P10	137	81	54	11	44	39	5	0	0	2
32	Total		457	271	180	35	145	129	16	0	0	6
33	Amortizations	LABOR	373	144	224	24	200	178	23	0	0	5
34	Total O&M Expense		170,097	62,169	106,315	10,332	95,982	84,776	11,206	0	0	1,614

Book Depreciation			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
		Alloc	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	Ltg
1	Production											
	Peaking Plant	D10C	3,901	1,265	2,624	238	2,386	2,134	252	0	0	12
2	Base Load	E8760	8,563	2,961	5,548	491	5,057	4,439	618	0	0	54
3	Total		12,464	4,226	8,173	729	7,443	6,573	870	0	0	65
Transmission												
4	Gen Step Up Base	E8760	60	21	39	3	36	31	4	0	0	0
5	Gen Step Up Peak	D10C	29	9	19	2	18	16	2	0	0	0
6	Total Gen Step Up		89	30	58	5	53	47	6	0	0	0
7	Bulk Transmission	D10T	2,271	770	1,490	141	1,349	1,207	142	0	0	11
8	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
9	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
10	Total		2,360	801	1,548	146	1,402	1,254	148	0	0	11
Distribution												
11	General Step Up	STRATH	8	3	5	0	5	4	1	0	0	0
12	Bulk Transmission	D10T	4	1	3	0	2	2	0	0	0	0
13	Distrib Function	D60Sub	608	224	379	34	345	304	41	0	0	6
14	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
15	Total Substations		620	228	386	34	352	310	42	0	0	6
16	Overhead Lines	POL	878	489	353	60	293	267	26	0	0	36
17	Underground	PUL	1,587	1,130	420	131	289	279	11	0	0	36
18	Line Transformers	P68	499	316	181	37	144	142	2	0	0	2
19	Services	P69	515	468	47	18	29	29	0	0	0	0
20	Meters	C12WM	227	141	83	32	51	47	4	0	0	4
21	Street Lighting	P73	81	0	0	0	0	0	0	0	0	0
22	Total		4,407	2,772	1,470	312	1,159	1,074	85	0	0	81
23	General Plant	PTD	1,118	435	672	68	603	536	68	0	0	11
24	Electric Common	PTD	2,214	862	1,330	135	1,195	1,061	134	0	0	23
25	Total Book Deprec		22,563	9,095	13,192	1,390	11,802	10,498	1,304	0	0	276
Real Estate & Property Tax												
Production												
26	Peaking Plant	D10C	1,315	426	885	80	804	719	85	0	0	4
27	Base Load	E8760	2,760	954	1,788	158	1,630	1,431	199	0	0	17
28	Total		4,075	1,381	2,673	239	2,434	2,150	284	0	0	21
Transmission												
29	Gen Step Up Base	E8760	48,2385	17	31	3	28	25	3	0	0	0
30	Gen Step Up Peak	D10C	22,9717	7	15	1	14	13	1	0	0	0
31	Total Gen Step Up		71,2102	24	47	4	43	38	5	0	0	0
32	Bulk Transmission	D10T	2,141.5786	726	1,405	133	1,272	1,138	134	0	0	10
33	Distrib Function	D60Sub	0.0000	0	0	0	0	0	0	0	0	0
34	Direct Assign	Dir Assign	0.2112	0	0	0	0	0	0	0	0	0
35	Total		2,213.000	751	1,452	137	1,315	1,176	139	0	0	11
Distribution												
36	General Step Up	STRATH	3	1	2	0	2	1	0	0	0	0
37	Bulk Transmission	D10T	1	0	1	0	1	1	0	0	0	0
38	Distrib Function	D60Sub	235	87	146	13	133	118	16	0	0	2
39	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
40	Total Substations		239	88	149	13	136	120	16	0	0	2
41	Overhead Lines	POL	356	198	143	24	119	108	10	0	0	14
42	Underground	PUL	643	458	170	53	117	113	4	0	0	15
43	Line Transformers	P68	157	100	57	12	45	45	1	0	0	1
44	Services	P69	162	147	15	6	9	9	0	0	0	0
45	Meters	C12WM	72	44	26	10	16	15	1	0	0	1
46	Street Lighting	P73	23	0	0	0	0	0	0	0	0	23
47	Total		1,652	1,035	560	118	443	410	33	0	0	56
48	General Plant	PTD	0	0	0	0	0	0	0	0	0	0
49	Electric Common	PTD	0	0	0	0	0	0	0	0	0	0
50	Tot RI Est & Pr Tax		7,940	3,167	4,685	493	4,192	3,736	456	0	0	88
51	Gross Earnings Tax	R01; R02	0	0	0	0	0	0	0	0	0	0
52	Payroll Taxes	LABOR	1,931	745	1,160	122	1,038	921	117	0	0	26
53	Tot Non-Inc Taxes		9,871	3,912	5,845	615	5,230	4,656	573	0	0	114

Provision For Defer Inc Tax			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
		Alloc	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	Ltg
1	Peaking Plant	D10C	1,653	536	1,112	101	1,011	904	107	0	0	5
2	Nuclear Fuel	E8760	(637)	(220)	(413)	(37)	(376)	(330)	(46)	0	0	(4)
3	Base Load	E8760	5,570	1,926	3,609	320	3,290	2,868	402	0	0	35
4	Total		6,586	2,242	4,308	384	3,924	3,462	463	0	0	36
Transmission												
5	Gen Step Up Base	E8760	1	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		1	0	1	0	1	1	0	0	0	0
8	Bulk Transmission	D10T	2,848	966	1,868	176	1,692	1,514	178	0	0	14
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		2,849	967	1,869	176	1,693	1,515	178	0	0	14
Distribution												
12	General Step Up	STRATH	(3)	(1)	(2)	(0)	(2)	(2)	(0)	0	0	(0)
13	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub	89	33	55	5	50	44	6	0	0	1
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
16	Total Substations		86	32	53	5	49	43	6	0	0	1
17	Overhead Lines	POL	35	19	14	2	12	11	1	0	0	1
18	Underground	PUL	(128)	(91)	(34)	(11)	(23)	(22)	(1)	0	0	(3)
19	Line Transformers	P68	(129)	(82)	(47)	(10)	(37)	(37)	(1)	0	0	(1)
20	Services	P69	(134)	(122)	(12)	(5)	(7)	(7)	0	0	0	0
21	Meters	C12WM	(11)	(7)	(4)	(2)	(2)	(2)	(0)	0	0	(0)
22	Street Lighting	P73	(8)	0	0	0	0	0	0	0	0	(8)
23	Total		(289)	(250)	(29)	(19)	(10)	(15)	5	0	0	(9)
24	General Plant	PTD	145	56	87	9	78	69	9	0	0	1
25	Electric Common	PTD	(309)	(120)	(186)	(19)	(167)	(148)	(19)	0	0	(3)
26	Net Operating Loss (NOL) Carry Forward	NEPIS	2,982	1,167	1,788	184	1,604	1,427	177	0	0	27
27	Non - Plant Related	LABOR	887	342	533	56	477	423	54	0	0	12
28	Tot Prov For Defer		12,851	4,404	8,370	771	7,599	6,732	867	0	0	77
Inv Tax Credit; Total Oper Exp												
Production												
29	Peaking Plant	D10C	(19)	(6)	(13)	(1)	(12)	(10)	(1)	0	0	(0)
30	Base Load	E8760	(38)	(13)	(25)	(2)	(22)	(20)	(3)	0	0	(0)
31	Total		(57)	(19)	(37)	(3)	(34)	(30)	(4)	0	0	(0)
Transmission												
32	Bulk Transmission	D10T	(33)	(11)	(22)	(2)	(20)	(18)	(2)	0	0	(0)
33	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
34	Total		(33)	(11)	(22)	(2)	(20)	(18)	(2)	0	0	(0)
Distribution												
35	General Step Up	STRATH	0	0	0	0	0	0	0	0	0	0
36	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0
37	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
38	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
39	Total Substations		0	0	0	0	0	0	0	0	0	0
40	Overhead Lines	POL	0	0	0	0	0	0	0	0	0	0
41	Underground	PUL	0	0	0	0	0	0	0	0	0	0
42	Line Transformers	P68	0	0	0	0	0	0	0	0	0	0
43	Services	P69	0	0	0	0	0	0	0	0	0	0
44	Meters	C12WM	0	0	0	0	0	0	0	0	0	0
45	Street Lighting	P73	0	0	0	0	0	0	0	0	0	0
46	Total		0	0	0	0	0	0	0	0	0	0
47	General Plant	PTD	0	0	0	0	0	0	0	0	0	0
48	Electric Common	PTD	(1)	(0)	(1)	(0)	(1)	(0)	(0)	0	0	(0)
49	Net Inv Tax Credit		(91)	(31)	(60)	(5)	(54)	(48)	(6)	0	0	(0)
50	Total Operating Exp		215,291	79,548	133,662	13,104	120,559	106,613	13,945	0	0	2,080
51A	Pres Op Inc Before Inc Tax		12,935	6,829	6,054	1,156	4,899	5,559	(661)	0	0	51
51B	Prop Op Inc Before Inc Tax		29,833	13,161	16,532	2,120	14,412	14,091	321	0	0	140

Tax Deprec; Inc Tax & Return			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Alloc	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	Ltg	
1	Production											
	Peaking Plant	D10C	8,946	2,901	6,018	546	5,472	4,893	579	0	0	27
2	Nuclear Fuel	E8760	5,361	1,854	3,474	307	3,166	2,779	387	0	0	34
3	Base Load	E8760	26,620	9,205	17,248	1,527	15,721	13,801	1,921	0	0	167
4	Total		40,927	13,960	26,740	2,380	24,359	21,473	2,886	0	0	228
Transmission												
5	Gen Step Up Base	E8760	62	22	40	4	37	32	4	0	0	0
6	Gen Step Up Peak	D10C	30	10	20	2	18	16	2	0	0	0
7	Total Gen Step Up		92	31	60	5	55	49	6	0	0	0
8	Bulk Transmission	D10T	10,250	3,477	6,724	635	6,089	5,448	640	0	0	49
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	1	0	1	0	1	0	1	0	0	0
11	Total		10,343	3,508	6,785	640	6,145	5,497	648	0	0	50
Distribution												
12	General Step Up	STRATH	0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10T	2	1	1	0	1	0	0	0	0	0
14	Distrib Function	D60Sub	842	310	524	46	478	421	57	0	0	8
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
16	Total Substations		844	310	525	47	479	422	57	0	0	8
17	Overhead Lines	POL	1,011	563	407	69	338	308	30	0	0	41
18	Underground	PUL	1,247	888	330	103	227	219	8	0	0	29
19	Line Transformers	P68	185	117	67	14	53	53	1	0	0	1
20	Services	P69	228	207	21	8	13	13	0	0	0	0
21	Meters	C12WM	184	114	67	26	41	38	3	0	0	3
22	Street Lighting	P73	59	0	0	0	0	0	0	0	0	59
23	Total		3,758	2,200	1,417	266	1,152	1,052	99	0	0	141
24	General Plant	PTD	2,011	783	1,208	123	1,085	963	122	0	0	21
25	Electric Common	PTD	1,420	553	853	87	766	680	86	0	0	15
26	Net Operating Loss (NOL) Carry Forward	NEPIS	10,641	4,165	6,380	656	5,723	5,091	632	0	0	97
27	Total Tax Deprec		69,100	25,168	43,382	4,152	39,230	34,757	4,473	0	0	550
28	Interest Expense		8,799	3,410	5,308	541	4,767	4,239	528	0	0	81
29	Other Tax Timing Differ		2,176	738	1,427	135	1,293	1,157	136	0	0	10
30	Total Tax Deductions		80,075	29,316	50,118	4,829	45,289	40,153	5,136	0	0	641
Inc Tax Additions												
31	Book Depreciation		22,563	9,095	13,192	1,390	11,802	10,498	1,304	0	0	276
32	Deferred Inc Tax & ITC		12,760	4,373	8,310	766	7,545	6,684	861	0	0	77
33	Nuclear Fuel Book Burr	E8760	7,249	2,507	4,697	416	4,281	3,758	523	0	0	45
34	Tax Capitalized Leases	PTD	4,664	1,815	2,801	285	2,516	2,235	282	0	0	48
35	Meals & Entertainment	LABOR	(47)	(18)	(28)	(3)	(25)	(22)	(3)	0	0	(1)
36	Avoided Tax Interest	RTBASE	3,051	1,182	1,841	188	1,653	1,470	183	0	0	28
37	Total Tax Additions		50,240	18,953	30,813	3,042	27,772	24,621	3,150	0	0	474
38	Total Inc Tax Adjustments		(29,835)	(10,362)	(19,305)	(1,787)	(17,518)	(15,532)	(1,986)	0	0	(168)
39A	Pres Taxable Net Income		(16,900)	(3,533)	(13,250)	(631)	(12,619)	(9,973)	(2,646)	0	0	(117)
39B	Prop Taxable Net Income		(2)	2,799	(2,772)	333	(3,106)	(1,441)	(1,664)	0	0	(28)
40A	Pres Fed & State Inc Tax		(6,481)	(1,355)	(5,081)	(242)	(4,839)	(3,824)	(1,015)	0	0	(45)
40B	Prop Fed & State Inc Tax		(1)	1,073	(1,063)	128	(1,191)	(553)	(638)	0	0	(11)
41A	Pres Preliminary Return	(total); BASE	19,416	8,184	11,136	1,398	9,738	9,383	354	0	0	96
41B	Prop Preliminary Return	(total); BASE	29,834	12,088	17,596	1,992	15,603	14,643	960	0	0	150
42	Total AFUDC		0	0	0	0	0	0	0	0	0	0
43A	Present Total Return		19,416	8,184	11,136	1,398	9,738	9,383	354	0	0	96
43B	Proposed Total Return		29,834	12,088	17,596	1,992	15,603	14,643	960	0	0	150
43C	Equal Total Return		29,834	11,562	17,998	1,836	16,162	14,373	1,789	0	0	275
44A	Pres % Return on Rate Base		5.14%	5.59%	4.89%	6.02%	4.76%	5.16%	1.56%	0.00%	0.00%	2.75%
44B	Prop % Return on Rate Base		7.90%	8.26%	7.72%	8.57%	7.63%	8.05%	4.24%	0.00%	0.00%	4.33%
44C	Equal % Return on Rate Base		7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	0.00%	0.00%	7.90%
45A	Present Common Return		10,616	4,774	5,827	857	4,971	5,144	(173)	0	0	15
45B	Proposed Common Return		21,035	8,678	12,287	1,451	10,836	10,404	432	0	0	69
46A	Pres % Ret on Common Rt Base		5.35%	6.21%	4.87%	7.01%	4.62%	5.38%	-1.46%	0.00%	0.00%	0.81%
46B	Prop % Ret on Common Rt Base		10.60%	11.28%	10.26%	11.88%	10.08%	10.88%	3.63%	0.00%	0.00%	3.80%

Allow For Funds Used During Constr		1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Alloc	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	Ltg
Production											
1	Peaking Plant	D10C	0	0	0	0	0	0	0	0	0
2	Nuclear Fuel	E8760	0	0	0	0	0	0	0	0	0
3	Base Load	E8760	0	0	0	0	0	0	0	0	0
4	Total		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
6	Gen Step Up Peak	D10C	0	0	0	0	0	0	0	0	0
7	Total Gen Step Up		0	0	0	0	0	0	0	0	0
8	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0
11	Total		0	0	0	0	0	0	0	0	0
Distribution											
12	General Step Up	STRATH	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0
16	Total Substations		0	0	0	0	0	0	0	0	0
17	Overhead Lines	POL	0	0	0	0	0	0	0	0	0
18	Underground	PUL	0	0	0	0	0	0	0	0	0
19	Line Transformers	P68	0	0	0	0	0	0	0	0	0
20	Services	P69	0	0	0	0	0	0	0	0	0
21	Meters	C12WM	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73	0	0	0	0	0	0	0	0	0
23	Total		0	0	0	0	0	0	0	0	0
24	General Plant	PTD	0	0	0	0	0	0	0	0	0
25	Electric Common	PTD	0	0	0	0	0	0	0	0	0
26	Total AFUDC		0	0	0	0	0	0	0	0	0
Labor Allocator											
Production											
27	Other Prod - Cap	D10C	74,009	23,998	49,789	4,518	45,271	40,483	4,788	0	223
28	Other Prod - Ene	E8760	155,413	53,741	100,697	8,914	91,783	80,569	11,214	0	975
29	Total		229,422	77,739	150,485	13,432	137,053	121,052	16,001	0	1,198
Transmission											
30	Stepup Subtrans	P5161A	483	164	317	28	288	255	34	0	3
31	Bulk Power Subs	D10T	14,532	4,930	9,532	900	8,632	7,724	908	0	70
32	Total		15,015	5,093	9,849	928	8,921	7,979	942	0	73
Distribution											
33	Superv & Eng	ZDTS	7,264	3,813	3,011	527	2,484	2,261	223	0	440
34	Load Dispatch	D10T	4,937	1,675	3,238	306	2,933	2,624	308	0	24
35	Substation	P61	4,117	1,513	2,565	227	2,338	2,060	278	0	39
36	Overhead Lines	POL	6,833	3,805	2,750	468	2,283	2,082	201	0	278
37	Underground Lines	PUL	7,664	5,459	2,029	631	1,398	1,346	52	0	176
38	Line Transformer	P68	1,326	839	481	98	383	378	5	0	6
39	Meter	C12WM	2,465	1,527	896	343	553	506	46	0	42
40	Cust Installation	ZDTS	2,602	1,366	1,078	189	890	810	80	0	158
41	Street Lighting	P73	982	0	0	0	0	0	0	0	982
42	Miscellaneous	OXDTS	5,661	3,024	2,125	392	1,733	1,581	152	0	512
43	Total		43,851	23,021	18,174	3,181	14,993	13,647	1,346	0	2,656
44	Cust Accounting	C11WA	12,343	9,810	2,486	1,474	1,012	1,000	13	0	47
45	Sales Expense	C11P10	36	54	36	7	29	3	0	0	1
46	Admin & General	LABOR	117,017	45,170	70,301	7,411	62,890	55,785	7,105	0	1,546
47	Service & Inform	C11P10	1,766	1,046	697	136	561	499	62	0	23
48	Labor		419,506	161,933	252,029	26,570	225,460	199,988	25,472	0	5,543

Northern States Power Company
 Electric Utility - State of North Dakota
 Test Year Ending 31 Dec 2013
 Proposed Class Cost of Service Study Detail

		1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10	
INTERNAL ALLOCATORS		MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	Ltg	
1	50% Cus, 50% Prod Pll	C11P10	100.000%	59.217%	39.494%	7.715%	31.779%	28.246%	3.533%	0.000%	0.000%	1.289%
2	Peaking Plant Capacity	D10C	100.000%	32.425%	67.274%	6.105%	61.169%	54.700%	6.469%	0.000%	0.000%	0.301%
3	57% Dmd; 43% Energy: Sales & ED	D57E43	100.000%	33.347%	66.212%	5.947%	60.265%	53.477%	6.788%	0.000%	0.000%	0.441%
4	40% Dmd; 60% Energy: CIP	D99E1	100.000%	32.451%	67.244%	6.100%	61.143%	54.666%	6.478%	0.000%	0.000%	0.305%
5	Labor w/o (or w/) A&G	LABOR	100.000%	38.601%	60.078%	6.334%	53.744%	47.672%	6.072%	0.000%	0.000%	1.321%
6	Net Plant In Service	NEPIS	100.000%	39.139%	59.953%	6.169%	53.784%	47.846%	5.938%	0.000%	0.000%	0.908%
7	Dis O&M w/o Sup & Misc	OXDTS	100.000%	53.423%	37.531%	6.923%	30.608%	27.923%	2.684%	0.000%	0.000%	9.046%
8	O&M w/o Reg Ex & OXTS-Alloc'd A&G	OXTS	100.000%	36.548%	62.504%	6.074%	56.429%	49.841%	6.589%	0.000%	0.000%	0.949%
9	Production Plant	P10	100.000%	34.043%	65.412%	5.828%	59.584%	52.555%	7.029%	0.000%	0.000%	0.546%
10	Production Plant Wo Nuclear	P10WoN	100.000%	33.885%	65.593%	5.855%	59.739%	52.764%	6.975%	0.000%	0.000%	0.522%
11	Total P51 & P61A	P5161A	100.000%	33.901%	65.574%	5.852%	59.722%	52.742%	6.980%	0.000%	0.000%	0.525%
12	Distribution Plant	P60	100.000%	62.674%	33.918%	7.130%	26.788%	24.793%	1.994%	0.000%	0.000%	3.408%
13	Distr Substn Plant	P61	100.000%	36.742%	62.307%	5.525%	56.782%	50.039%	6.742%	0.000%	0.000%	0.952%
14	Line Transformer Plant	P68	100.000%	63.267%	36.284%	7.375%	28.909%	28.510%	0.399%	0.000%	0.000%	0.449%
15	Services Plant	P69	100.000%	90.942%	9.058%	3.502%	5.556%	0.000%	0.000%	0.000%	0.000%	0.000%
16	Dist Pll Overhead Lines	POL	100.000%	55.679%	40.253%	6.842%	33.410%	30.466%	2.945%	0.000%	0.000%	4.069%
17	Real Est & Property Tax	PTO	100.000%	39.8839%	59.005%	6.211%	52.793%	47.049%	5.745%	0.000%	0.000%	1.112%
18	Produc, Trans & Distrib	PTD	100.000%	38.912%	60.064%	6.110%	53.954%	47.911%	6.044%	0.000%	0.000%	1.024%
19	Dist Pll Underground Lines	PUL	100.000%	71.232%	26.476%	8.238%	18.238%	17.559%	0.679%	0.000%	0.000%	2.292%
20	Rate Base (Non-Column)	RTBASE	100.000%	38.753%	60.327%	6.153%	54.173%	48.178%	5.996%	0.000%	0.000%	0.921%
21	Stratified Hydro Baseload	STRATH	100.000%	34.248%	65.175%	5.793%	59.383%	52.282%	7.100%	0.000%	0.000%	0.577%
22	Transmission & Distrib	TD	100.000%	48.426%	49.616%	6.660%	42.956%	38.838%	4.118%	0.000%	0.000%	1.958%
23	Labor Dis w/o Sup & Eng	ZDTS	100.000%	52.499%	41.445%	7.254%	34.191%	31.122%	3.069%	0.000%	0.000%	6.056%
INTERNAL DATA		MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	Ltg	
24	Labor w/o A&G	LABOR(S)	302,489	116,764	181,728	19,158	162,570	144,203	18,367	0	0	3,997
25	Dis O&M w/o Sup, Cust Install & Misc	OXDTS	5,245	2,802	1,968	363	1,605	1,465	141	0	0	474
26	O&M w/o Reg Ex & OXTS-Alloc'd A&G	OXTS	167,164	61,095	104,484	10,154	94,330	83,316	11,014	0	0	1,586
27	Total P51 & P61A	P5161A	4,596	1,558	3,014	269	2,745	2,424	321	0	0	24
28	Produc, Trans & Distrib	PTD	811,976	315,957	487,703	49,608	438,095	389,023	49,073	0	0	8,316
29	Transmission & Distrib	TD	274,898	133,121	136,392	18,309	118,084	106,764	11,320	0	0	5,384
30	Labor Dis w/o Sup & Eng, Cust Install	ZDTS	33,985	17,842	14,085	2,465	11,620	10,577	1,043	0	0	2,058

		1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10	
EXTERNAL ALLOCATORS		Extern:	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	Ltg
1	Customers - Ave Monthly	C11	100.00%	84.39%	13.58%	9.60%	3.97%	3.94%	0.04%	0.00%	0.00%	2.03%
2	Cust Acctg Wtg Factor	C11WA	100.00%	79.48%	20.14%	11.94%	8.20%	8.10%	0.10%	0.00%	0.00%	0.38%
3	Mo Cus Wtd By Mir Invest	C12WM	100.00%	61.96%	36.36%	13.93%	22.42%	20.54%	1.88%	0.00%	0.00%	1.69%
4	Sec & Pri Customers	C61PS	100.00%	86.04%	13.82%	8.74%	4.07%	4.04%	0.04%	0.00%	0.00%	0.14%
5	C62Sec, w/o Ltg & C/I Underground	C62NL	100.00%	94.69%	5.31%	3.75%	1.55%	1.55%	0.00%	0.00%	0.00%	0.00%
6	Secondary Customers	C62Sec	100.00%	86.07%	13.78%	9.75%	4.04%	4.04%	0.00%	0.00%	0.00%	0.14%
7	Summer Peak Resp KW	D10S	100.00%	29.93%	70.07%	5.96%	64.11%	57.27%	6.84%	0.00%	0.00%	0.00%
8	Transmission Demand %	D10T	100.00%	33.92%	65.80%	8.19%	59.40%	53.16%	6.25%	0.00%	0.00%	0.48%
9	Winter Peak Resp KW	D10W	100.00%	39.37%	59.49%	6.51%	52.98%	47.53%	5.44%	0.00%	0.00%	1.14%
10	Alternative Production Allocator	AED4CP	100.00%	29.34%	70.32%	6.52%	63.80%	57.26%	6.54%	0.00%	0.00%	0.34%
11	Sec, Pri & TT, Class Coin kW @ Substation	D60Sub	100.00%	36.78%	62.26%	6.52%	56.74%	50.00%	6.74%	0.00%	0.00%	0.96%
12	Sec & Pri, CI Coin kW (no Min Sys; adj Res W/)	D61PS	100.00%	32.55%	66.60%	4.93%	61.67%	54.27%	7.41%	0.00%	0.00%	0.85%
13	D62Sec, w/o Ltg & C/I Underground	D62NLL	100.00%	80.98%	19.02%	2.84%	16.19%	16.19%	0.00%	0.00%	0.00%	0.00%
14	Sec, Class Coin kW (w/o Min Sys kW)	D62SecL	100.00%	47.37%	51.96%	5.64%	46.32%	46.32%	0.00%	0.00%	0.00%	0.66%
15	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%
16	On + Off Sales MWH	E8760	100.00%	34.58%	64.79%	5.74%	59.06%	51.84%	7.22%	0.00%	0.00%	0.63%
17	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%
18	Present Rev	R01	100.00%	38.56%	60.42%	6.33%	54.08%	48.52%	5.57%	0.00%	0.00%	1.02%

		1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10	
APPLIED EXTERNAL DATA		MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	Ltg	
19	Customers - B Basis	C10	89,565	77,063	12,374	8,726	3,648	3,614	33	0	0	128
20	Cust - Ave Monthly (C10-Area Lt)	C11	91,774	77,450	12,459	8,812	3,648	3,614	33	0	0	1,865
21	Mo Cus Wtd By Cus Acct	C11WA	95,594	75,975	19,253	11,414	7,839	7,741	98	0	0	366
22	Cust Acctg Wtg Factor	C11WAF	7.35	0.98	6.37	1.30	5.07	2.14	2.93	0.00	0.00	N/A
23	Cust-Ave Mo (C11 w/ Dir Assign St Ltg)	C12	91,431	77,450	12,459	8,812	3,648	3,614	33	0	0	1,522
24	Mo Cus Wtd By Mir Invest	C12WM	10,725,904	6,645,497	3,899,673	1,494,491	2,405,182	2,203,155	202,027	0	0	180,733
25	Meter Invest / Cust Factor	C12WMF	7,032	86	6,828	170	6,658	610	6,049	0	0	119
26	Sec & Pri Customers	C61PS	89,565	77,063	12,374	8,726	3,648	3,614	33	0	0	128
27	C62Sec, w/o Ltg & C/I Underground	C62NL	81,382	77,063	4,319	3,054	1,265	1,265	0	0	0	0
28	Secondary Customers	C62Sec	89,531	77,063	12,340	8,726	3,614	3,614	0	0	0	128
29	Summer Peak Resp KW	D10S	495	148	347	29	317	283	34	0	0	0
30	Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	3,392,295	6,559,551	619,281	5,940,269	5,315,505	624,764	0	0	48,154
31	Winter Peak Resp KW	D10W	428	169	255	28	227	203	23	0	0	5
32	Alternative Production Allocator	AED4CP	10,000,000	2,933,939	7,031,571	651,649	6,379,922	5,725,548	654,374	0	0	34,490
33	Sec, Pri & TT, Class Coin kW @ Substation	D60Sub	566,768	208,479	352,857	31,278	321,579	283,372	38,207	0	0	5,432
34	Sec & Pri, Class Coin kW (w/o Min Sys; reducec	D61PS	515,278	167,718	343,192	25,402	317,790	279,625	38,165	0	0	4,368
35	D62Sec, w/o Ltg & C/I Underground	D62NLL	778,581	630,468	148,113	22,087	126,026	126,026	0	0	0	0
36	Sec, Class Coin kW (w/o Min Sys kW)	D62SecL	10,000,000	4,737,112	5,196,472	564,431	4,632,041	4,632,041	0	0	0	66,416
37	Annual Billing kW	D99	3,581,533	0	3,582	0	3,582	0	343	0	0	0
38	Summer Billing kW	D99S	1,257,547	0	1,258	0	1,258	0	128	0	0	0
39	Winter Billing kW	D99W	2,323,986	0	2,324	0	2,324	0	215	0	0	0
40	Non-Coinc Pk Second	DN-Sec	1,058,016	630,468	423,181	63,105	360,075	360,075	0	0	0	4,368
41	kWh Sales @ Meter	E99	2,270,721	784,751	1,466,635	125,788	1,340,847	1,172,103	168,745	0	0	19,336

Northern States Power Company
 Electric Utility - State of North Dakota
 Test Year Ending December 31, 2013
VOLTAGE DISCOUNT ANALYSIS - DEMAND (\$/kW)

Case No. PU-12-____
 Exhibit____(MAP-1), Schedule 5
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Includes losses to indicate additional billing kW low voltage customers would have at higher voltage.

	Secondary Costs	Primary Costs	
	Lines & Transformers	Lines & Transformers	Distribution Substation
1. Revenue Requirement (\$000s):			
(CCOSS; p. 2; lines 33,32,31)	\$1,693.266	\$2,129.637	\$1,744.660
2. Billing kW			
Secondary Voltage kW	3,238,674	3,238,674	3,238,674
Loss Factor	1.0000	1.0202	1.0422
Secondary With Losses	3,238,674	3,304,124	3,375,392
Primary Voltage kW		342,859	342,859
Loss Factor		1.0000	1.0216
Primary With Losses		342,859	350,254
Transmission Transformed Voltage kW			0
Total kW (Metered Sales + Losses)	3,238,674	3,646,983	3,725,645
3. Rev Req/ kW (Line 1 / Line 2)	\$0.5228	\$0.5839	\$0.4683
4. Cumulative Rev Req/ kW	\$0.52	\$1.11	\$1.58
5. Present Individual Discounts	\$0.62	\$0.48	\$0.30
6. Cumulative Present Discount	\$0.62	\$1.10	\$1.40
7. Midpoint-Pres and Rev Req/ (Lines 4+ 6 /2)	\$0.57	\$1.10	\$1.49
8. Cumulative Proposed Discount (Rounded to nearest \$0.05)	\$0.60	\$1.10	\$1.50

VOLTAGE DISCOUNT ANALYSIS - ENERGY (¢/kWh)

	[1] E8760 <u>Losses</u>	[2] Percent <u>Difference</u>	[3] Energy <u>Charge</u>	[4] Cost-Based <u>Discount</u>	[5] Proposed <u>Discount</u>	[6] Present <u>Discount</u>	
<u>Voltage</u>							
Secondary	10.95%	0.00%	5.652	0.0000	0.000	0.000	¢ per kWh
Primary	9.15%	1.80%	5.550	0.1015	0.102	0.095	¢ per kWh
T Transformed	7.24%	3.71%	5.443	0.2095	0.210	0.200	¢ per kWh
Transmission	6.75%	4.20%	5.415	0.2373	0.240	0.220	¢ per kWh