Direct Testimony and Schedules
Michael A. Peppin

Before the South Dakota Public Utilities Commission
State of South Dakota

In the Matter of the Application of Northern States Power Company,
a Minnesota corporation

For Authority to Increase Rates for
Electric Service in South Dakota

Docket No. EL11-____
Exhibit___(MAP-1)

Class Cost of Service Study
and
Selected Rate Design

June 30, 2011

Table of Contents

Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael A. Peppin. My business address is 414 Nicollet Mall, 7th Floor, Minneapolis, Minnesota, 55401.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Xcel Energy Services Inc., which is the service company subsidiary of Xcel Energy Inc. My title is Principal Pricing Analyst. I am providing testimony on behalf of Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company"), operating in South Dakota.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. My qualifications include more than 29 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. The purpose of my testimony is to 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
  - General Rules and Regulations

II. CLASS COST OF SERVICE STUDIES

A. Proposed Class Cost of Service Study

Q. HOW DOES THE COMPANY'S PROPOSED CCOSS COMPARE WITH THAT APPROVED BY THE SOUTH DAKOTA PUBLIC SERVICE COMMISSION ("COMMISSION") IN THE COMPANY'S LAST GENERAL ELECTRIC RATE CASE, DOCKET NO. EL09-009?

A. The Company's proposed CCOSS reflects new test year ("TY") 2010 data, but no changes have been made in the cost-study process or allocation methods approved by the Commission in the last general electric rate case.

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

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

Q. PLEASE SUMMARIZE THE RESULTS OF THE PROPOSED CCOSS.

A. Table 1 below provides a summary of the CCOSS results at the class level. More information is shown on Exhibit___(MAP-1), Schedule 3. The detailed CCOSS output is shown on Exhibit___(MAP-1), Schedule 4, and on Exhibit___(NSP-1), Statement O, located in Volume 1.

Table 1 below shows the resulting class cost responsibilities (as opposed to proposed revenue responsibilities, which are addressed by Mr. Huso). These CCOSS results indicate what change from present rates would be necessary to result in equal rates of return on investment for each class (i.e. the increase in rates necessary to produce equalized rates of return).

Table 1

Summary of 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 2)	171,754	72,744	9,941	87,402	1,667
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21+ line 23)	48	20	3	25	0
[3]	Unadjusted Operating Revenues (line 2 + line 3)	171,802	72,764	9,943	87,427	1,668
[4]	Present Rates (CCOSS page 2, line 3)	157,219	65,967	9,043	80,700	1,508
[5]	Unadjusted Deficiency (line 3 - line 4)	14,583	6,797	900	6,726	160
[6]	Defic / Pres (line 5 / line 4)	9.3%	10.3%	10.0%	8.3%	10.6%
[7]	**Ratio: Class % / Total %**	**1.00**	**1.11**	**1.07**	**0.90**	**1.14**
	CAPACITY COST RESPONSIBILITIES FOR INTERRUPTIBLE RATE DISCOUNTS					
		Total	**Resid**	**Non-Demand**	**Demand**	**Street Ltg**
[8]	Interruption Rate Discounts (CCOSS page 2, line 6)	2,691	1,034	23	1,633	0
[9]	Interruption Capacity Costs (CCOSS page 2, line 7)	2,691	1,092	151	1,441	7
[10]	Revenue Requirement Shift (line 9 - line 8)	0	57	127	(192)	7
	ADJUSTED COST RESPONSIBILITIES: TY 2010					
		Total	**Resid**	**Non-Demand**	**Demand**	**Street Ltg**
[11]	Adjusted Rate Revenue Reqt (line 1 + line 10)	171,754	72,801	10,068	87,210	1,674
[12]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21+ line 23)	48	20	3	25	0
[13]	Adjusted Operating Revenues (line 11 + line 12)	171,802	72,821	10,071	87,235	1,675
[14]	Present Rates (line 4)	157,219	65,967	9,043	80,700	1,508
[15]	Adjusted Deficiency (line 13 - line 14)	14,583	6,854	1,027	6,535	167
[16]	Defic / Pres Rates (line 15 / line 4)	9.3%	10.4%	11.4%	8.1%	11.1%
[17]	**Ratio: Class % / Total %**	**1.00**	**1.12**	**1.22**	**0.87**	**1.19**

* Figures are rounded to nearest whole numbers.

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

A. The distinction between "adjusted" and "unadjusted" cost responsibilities relates to how the "cost" of interruptible capacity is reflected in the CCOSS. The method used to reflect those costs is the same as that used in the Company's last general electric rate case, Docket No. EL09-009.

Unadjusted cost responsibilities are those that were historically used as the indicators of class cost responsibilities. However, as the size of the Company's interruptible programs grew, it became clear that these traditional unadjusted cost responsibilities did not properly account for the fact that interruptible rate discounts are really the "cost" of this particular source of generation peaking capacity. Therefore, the Company modified the CCOSS to produce adjusted cost responsibilities. The adjusted cost responsibilities appropriately account for the cost of this particular source of peaking capacity. Doing so is appropriate and important, because interruptible rate discounts (lost revenues) are a real cost of service arising from this particular alternative source of peaking capacity.

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

A. As the Company indicated in its previous rate case, the economic essence of a utility's "obligation to serve" is to provide low-cost reliable <u>firm</u> electric service. Interruptible "service" is really firm service, attached to which is an after-the-fact purchased-power contract provision. Through this contract provision, the Company has the option to buy back (from willing customers) all or part of their "regulatory entitlement" to firm service. The resulting capacity purchase transactions occur when, and if, doing so is a cost-effective source of peaking capacity, which helps the Company obtain a reliable power-supply portfolio at the lowest cost. This means interruptible rate discounts are really power-supply costs, and they need to be recognized as such in the CCOSS.

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

A. To accomplish this interruptible capacity cost accounting, the Company has added lines to the CCOSS model.

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

Q. PLEASE EXPLAIN HOW THE RESULTS OF THE COMPANY'S PROPOSED CCOSS ARE USED IN DEVELOPING THE PROPOSED RATES.

A. The Company uses the proposed CCOSS as the basis for evaluating and refining its rate structure. Mr. Huso uses it as a guide in determining the proposed class revenue responsibilities and for determining the proposed rate design for each tariff. The Company's proposed revenue allocation is provided on Exhibit___(MAP-1), Schedule 3, lines 18 through 23.

III. SELECTED RATE DESIGN REVISIONS

A. 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 TY 2010 CCOSS indicate that a decrease in the demand charge discounts for Primary and Transmission Transformed voltage customers (as shown on lines 4 and 6 of page 1 of Exhibit___(MAP-1), Schedule 5) and an increase in energy charge discounts (as shown on columns 4 and 6 of page 2 of Exhibit___(MAP-1), Schedule 5) would move rates closer to the cost of service.

Table 2 below summarizes the cost analysis provided in Exhibit___(MAP-1), Schedule 5. It compares the TY 2010 costs to the present and proposed voltage discounts.

Table 2

Voltage Discount Analysis

C&I Voltage Discounts - Demand			
Rate	**Primary**	**Transmission Transformed**	**Transmission**
CCOSS Revenue Req	$0.689	$1.377	$1.956
Present	$0.80	$1.50	$2.00
Midpoint - between cost and present discount	$0.74	$1.44	$1.98
Proposed	$0.70	$1.40	$2.00
C&I Voltage Discounts - Energy			
Rate	**Primary**	**Transmission Transformed**	**Transmission**
Revenue Req	0.1028¢	0.2480¢	0.2656¢
Present	0.08¢	.14¢	0.20¢
Proposed	0.10¢	0.25¢	0.27¢

B. General Rules and Regulations

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

A. The following are the areas in the General Rules and Regulations where the Company is proposing revisions.

- Service Reconnection Charge Section 1.2
- Dedicated Switching Charges Section 1.8
- Excess Footage Charges Section 5.1.A.1
- Winter Construction Charges Section 5.1.A.2

The following is an explanation of these proposed changes. A red-line version of all of the proposed changes described below can be reviewed in Volume 2 of the rate case application.

1. Service Charges--Section 1.2

Q. WHAT REVISIONS ARE BEING PROPOSED FOR THE COMPANY'S SERVICE CHARGES TARIFF?

A. The Company is proposing two revisions in the Service Charges tariff. The first proposal is to increase the Service Reconnection Charge from the present $22.50 to $50.00, as indicated on Sheet No. 6-3 of the General Rules and Regulations. This increase is necessary to reflect the costs associated with physically reconnecting a customer service line after the customer's service line has been disconnected. This Service Reconnection is distinct from the more common Service Processing activity, where no physical disconnection is involved. Service Reconnections occur where a customer has been disconnected for non-payment or in cases where a customer has requested that their service be disconnected because the premises will be unoccupied for some extended period. The cost analysis supporting the higher costs of reconnection is provided in Exhibit___(MAP-1), Schedule 6, page 1 of 4.

The second revision to Section 1.2 involves a tariff language revision. The revision is the addition of language at the end of Section 1.2 to make it clear when either the Service Processing Charge or Service Reconnection Charge applies. The application of one or the other depends on whether a customer requests a simple discontinuance and subsequent reestablishment of electric service within a 12-month period or requests that the service be physically disconnected.

Customer requests for temporary discontinuance of service generally come from those with a summer home not used during the winter months or from customers who move south for part of the winter season.

The language revision makes it clear that for ordinary service discontinuance (i.e. no physically disconnection), the Service Processing Charge of $15.00 applies. However, in cases where the customer requests actual physical disconnection of the service and subsequently requests reconnection within a 12 month period, the higher $50.00 Service Reconnection Charge applies.

2. *Dedicated Switching Charges--Section 1.8*

Q. WHAT IS DEDICATED SWITCHING?

A. Dedicated Switching is a service requested by a few large C&I customers. It typically occurs when a customer needs to perform work on its own facilities and where doing so requires that the electric service be de-energized. This service takes place at a customer-specified date and time, which is often outside of normal business hours. Providing this service requires taking a

Company service crew off of normal work activities and dispatching them to de-energize the service so the customer can do their internal work. The Company's crew then restores the customer's service as soon as the customer completes its work. The Company is proposing a specific charge for this service consistent with its Minnesota and South Dakota jurisdictions, as detailed on Sheet No. 6-4 of the General Rules and Regulations.

Q. WHAT ARE THE PROPOSED CHANGES TO THE DEDICATED SWITCHING SERVICE CHARGES?

A. The proposed Dedicated Switching Service tariff provides two hourly rates for this service that reflect current costs. For Dedicated Switching Service provided on Monday through Saturday, the proposed rate is revised from $250.00 to $300.00 per hour. The proposed rate for this service provided on Sundays or Holidays is revised from $300.00 to $400.00 per hour. The cost analysis supporting these charges is provided on Page 2 of Exhibit___(MAP-1), Schedule 6.

3. Excess Footage Charge--Section 5.1.A.1

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

A. The Company is proposing an increase to the existing Excess Footage Charge for Residential Service Lines from $6.85 to $7.90 per foot, as indicated on Sheet No. 6-23 of the General Rules and Regulations. The Company is proposing to increase excess footage charges for Non-Residential distribution laterals. The proposed charge for an Excess Single Phase Primary or Secondary Extension is from $7.50 to $8.00 per foot, and the proposed charge for an Excess Three Phase Primary or Secondary Extension is from $9.50 to

$13.90 per foot, which are also indicated on Sheet No. 6-23 of the General Rules and Regulations.

The cost analysis supporting these charges is provided on page 3 of Schedule 6 of Exhibit___(MAP-1).

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

Q. WHAT REVISIONS ARE PROPOSED IN THE WINTER CONSTRUCTION CHARGES?

A. There are two components to the Winter Construction Charges, as indicated on Sheet No. 6-24 of the General Rules and Regulations. Based on the cost analysis shown on page 4 of Exhibit___(MAP-1), Schedule 6, the Company is proposing to increase the winter construction Thawing charge from $400 to $600 per frost burner, and to increase the Service, Primary or Secondary Distribution Extension charge from $3.00 per trench foot to $3.80 per trench foot.

Q. WHAT IS THE REVENUE IMPACT OF THESE PROPOSED INCREASED GENERAL SERVICE CHARGES?

A. The revenue impact of increasing these General Service charges is reflected on Exhibit___(MAP-1) Schedule 3, Line 2; and Schedule 4, Page 7, Line 21.

IV. CONCLUSION

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

A. In summary, based on the results of the CCOSS, the major customer classes have the following revenue deficiencies, stated as a percentage of present revenues:

- Residential Customers 10.39%
- Commercial Non Demand Customers 11.36%
- Commercial and Industrial Demand Billed Customers 8.10%
- Lighting 11.07%

In addition, the CCOSS supports the following changes to the demand and energy voltage discounts for the C&I Demand Class:

	Voltage Discounts: Demand ($ per kW)		**Voltage Discounts: Energy ($ per kWh)**	
Voltage Level	**Current Discounts**	**Proposed Discounts**	**Current Discounts**	**Proposed Discounts**
Primary	$0.80	$0.70	$0.0008	$0. 0010
Transmission Transformed	$1.50	$1.40	$0.0014	$0. 0025
Transmission	$2.00	$2.00	$0.0020	$0. 0027

Finally, based on updated cost analyses, an increase in the following charges is justified:

- Service Reconnections
- Dedicated Switching
- Excess Footage Charges
- Winter Construction Charges

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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.

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Guide to the Class Cost of Service Study (CCOSS)
Northern States Power Co
South Dakota Electric

I. Overview

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

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

II. Major Steps of the Class Cost of Service Study

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

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

III. Step 1: Functionalization

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

Function	**FERC Accounts**	**Sub-Function**	**Description**
Generation (Move this row down under winter capacity.)	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 and associated substation facilities 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.

Function	FERC Accounts	Sub-Function	Description
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 (and also of the purchased power contract costs) 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 South Dakota rate case (test year 2010) is shown in the table below. It compares the then current-dollar replacement costs of each plant type, to develop stratification percentages.

Plant Type	$/kW	Capacity Ratio	Capacity %	Energy %
Peaking	$672	$672 / $672	100%	0%
Combined Cycle	$966	$672 / $966	69.5%	30.5%
Nuclear	$3,427	$672 / $3,427	19.6%	80.4%
Fossil	$1,803	$672 / $1,803	37.3%	62.7%
Hydro	$4,453	$672 / $4,453	15.1%	84.9%
Wind	$19,168	$672 / $19,168	3.5%	96.5%

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. book investment, accumulated depreciation, net plant, cost of capital, income taxes, etc.), for each generation plant type.

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

Once the "capacity-related" portion of generation plant costs have been quantified, they 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 4-month summer (June, July, August and September) and an 8-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 TY2010 South Dakota rate case is shown below.

(1)	**(2)**	**(3)**	**(4) = (3) minus 5,245**
Month	**Season**	**Monthly NSP System Peak Load**	**Monthly Peak in Excess of Average Hourly Load**
Jan	Winter	6,722	1,450
Feb	Winter	6,414	1,142
Mar	Winter	5,895	623
Apr	Winter	5,844	572
May	Winter	8,474	3,202
Jun	Summer	8,366	3,094
Jul	Summer	8,889	3,617
Aug	Summer	9,131	3,859
Sep	Summer	6,888	1,616
Oct	Winter	6,277	1,005
Nov	Winter	6,631	1,359
Dec	Winter	6,848	1,576
Average Annual Load		**5,272**	
Average Monthly Excess			
Average of Summer Months			3,046
Average of Winter Months			1,366
Total			4,412
Summer Percent			**69.04%** = 3,046/4,412
Winter Percent			**30.96%** = 1,366 / 4,412

As shown above, 69.04% of generation capacity costs were assigned to the summer season while 30.96% 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 <u>classify</u> the functionalized costs as being associated with a measurable customer service requirement which gives rise to the costs. The 3 principle service requirements or billing components are:

1. Demand – Costs that are driven by the customer's maximum kilowatt ("kW") demand.
2. Energy – Costs that are driven by the customer's 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 Lines	X		X
Primary Transformers	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	42.2%
Primary Transformers	0%
Overhead Lines Secondary	54.9%
Underground Lines Primary	85.9%
Underground Lines Secondary	54.3%
Line Transformers Secondary	48.8%
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 2 ways:

- Direct Assignment - A small but sometimes important portion of costs can be directly assigned to a specific customer of a particular customer class, because these costs can be exclusively identified as providing service to a particular customer. Examples of costs that are directly assigned include:
  - Customer-dedicated transmission radial lines or dedicated distribution substations
  - Street lighting facility costs
- Allocation - Most electric utility costs are incurred in common or jointly in providing service to all or most customers and classes. Therefore, allocation methods have to be developed for each functionalized and classified cost component. The allocation method is based on the particular measures of service that is indicative of what drives the costs.
  - Class allocators (sometimes called allocation strings) are simply a "string" of class percentages that sum to 100%.
  - There are 2 types of allocators:
    - External Allocators –These are the more interesting allocators that are based on data from outside the CCOSS model (e.g. load research data, metering and customer service-related cost ratios). In general, there are 3 types of external allocators:
      - Capacity –related (sometimes referred to as Demand) allocators such as:
        - System coincident peak (CP) responsibility or class contribution to system peak (1CP, 4CP or 12CP)
        - Class peak or non-coincident peak
        - Individual customer maximum demands
      - Energy-related allocators such as:
        - kWh at the customer (kWh sales)
        - kWh at the generator (kWh sales plus loses)
        - kWh energy, weighted by the variable cost of the energy
      - 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 kWs demand, kWhs of energy or the number of customers. Examples of internal allocators include:

- PTD – Production, transmission and distribution plant investment.
- OXDTS – Distribution O&M expenses without supervision and miscellaneous expenses.

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 and
4. Street & Outdoor Lighting

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

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

More detail on customer class definitions is shown in Appendix 3.

VII. CCOSS Data Inputs

As noted earlier, there are a large number of inputs to the CCOSS model including detailed rate base and expense items from the Jurisdictional Cost of Service Study (JCOSS) as well as numerous inputs from other sources used to develop external allocators.

VIII. Organization of the CCOSS Model

The CCOSS model consists of numerous worksheets which show costs by customer class in Total and at the following more detailed levels including Billing Unit, Function and Sub-function as shown below:

1. Billing Unit:

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

2. Function and Associated Sub-Function:

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

b. Transmission (Trans)

c. Distribution (Dist): Sub-functions include:
   a) Distribution Substations (Psub)
   b) Primary Voltage? (Prim)
   c) Secondary Voltage? (Sec)

d. 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. The label for each worksheet tab is show in parentheses above. This multi-level breakdown of costs is useful for designing rates as well as for determining class revenue responsibilities.

IX. 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:

Retail Revenue Requirement =

Expenses (including off-setting credits from Other Operating Revenues)
+
((Return on Investment x Rate Base) – AFUDC) x 1 / (1-Tax Rate)
+
(Tax Additions – Tax Deductions) x Tax Rate / (1-Tax Rate)

Where:

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

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

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

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

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

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

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

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

XI. CCOSS Output

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

<table>
<tr><th colspan="4">Final CCOSS Printout "Tot" Worksheet</th></tr>
<tr><th>CCOSS Section</th><th>Page Number</th><th>Results Detail</th><th>Line Numbers</th></tr>
<tr><td rowspan="4">Results Summary</td><td rowspan="2">1</td><td>Rate Base Summary</td><td>1-23</td></tr>
<tr><td>Income Statement Summary</td><td>24-34</td></tr>
<tr><td>2</td><td>Proposed Cost Responsibility at <u>Equal ROR</u> (the cost of service) compared to Present Rate Revenue Responsibility</td><td>1-50</td></tr>
<tr><td>3</td><td>Proposed Cost Responsibility at <u>Equal ROR</u> (the cost of service) compared to Proposed Rate Revenue Responsibility</td><td>1-54</td></tr>
<tr><td rowspan="5">Rate Base Detail</td><td>4</td><td>Original Plant in Service</td><td>1-48</td></tr>
<tr><td rowspan="2">5</td><td>MINUS Accumulated Depreciation</td><td>1-27</td></tr>
<tr><td>MINUS Accumulated Deferred Income Tax</td><td>28-58</td></tr>
<tr><td rowspan="2">6</td><td>PLUS Construction Work in Progress</td><td>1-35</td></tr>
<tr><td>EQUALS Total Rate Base</td><td>36</td></tr>
<tr><td rowspan="20">Income Statement Detail</td><td rowspan="2">7</td><td>Present and Proposed Revenues</td><td>1-26</td></tr>
<tr><td>MINUS O&M Expenses part 1</td><td>27-41</td></tr>
<tr><td>8</td><td>MINUS O&M Expenses part 2</td><td>1-34</td></tr>
<tr><td rowspan="2">9</td><td>MINUS Book Depreciation</td><td>1-25</td></tr>
<tr><td>MINUS Real Estate & Property Taxes</td><td>26-53</td></tr>
<tr><td rowspan="3">10</td><td>MINUS Provision for Deferred Income Tax</td><td>1-28</td></tr>
<tr><td>MINUS Investment Tax Credit</td><td>29-41</td></tr>
<tr><td>EQUALS Present and Proposed Operating Income Before Income Taxes</td><td>42A
42B</td></tr>
<tr><td rowspan="7">11 (Income Tax Calcs.)</td><td>Tax Additions</td><td>31-37</td></tr>
<tr><td>MINUS Tax Deductions</td><td>1-30</td></tr>
<tr><td>EQUALS Total Tax Adjustments</td><td>39A
39B</td></tr>
<tr><td>PLUS Present and Proposed Operating Income Before Income Taxes</td><td>40A
40B</td></tr>
<tr><td>EQUALS Present and Proposed Taxable Income</td><td>39A
39B</td></tr>
<tr><td>MULTIPLIED BY State and Federal Tax Rates</td><td></td></tr>
<tr><td>EQUALS Present and Proposed State and Federal Income Taxes</td><td>40A
40B</td></tr>
<tr><td rowspan="5">11 (Total Return Calcs.)</td><td>Present and Proposed Operating Income Before Income Taxes</td><td>FROM Page 10, Rows 42A & 42B</td></tr>
<tr><td>MINUS Present and Proposed State and Federal Income Taxes</td><td>40A
40B</td></tr>
<tr><td>EQUALS Present and Proposed Preliminary Return</td><td>41A
41B</td></tr>
<tr><td>PLUS AFUDC (from page 12)</td><td>42</td></tr>
<tr><td>EQUALS Present and Proposed Total Return</td><td>43A
43B</td></tr>
</table>

XI. CCOSS Output (continued)

CCOSS Section	Page Number	Results Detail	Line Numbers
Misc Calcs	12	AFUDC	1-26
		Labor Allocator	27-48
	13	Backwards Revenue Calculations	1-36
Allocator Data	14	Internal Allocators and Associated Data	1-32
	15	External Allocators and Associated Data	1-44
Misc CCOSS Data Inputs	16	On Peak Energy Weighting Factor, Summer Factor, Minimum System Splits, Plant Stratification Data, Tax Rates, Capitol Structure, Etc.	1-58

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

Code	Allocator for:	Description	Allocator Rationale & Background
C11	**Connection charge revenues**	**Average monthly customers: Forecasted annual bills / 12**	**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.	
C11WA	**Customer accounting costs**	**Average monthly customers weighted by each class' relative rating of customer accounting costs: C11 X C11WAF**	**Customer accounting costs are driven by number of customers and the complexity of their respective rate, billing issues and customer service requirements.**
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.
C12WM	**Meter costs**	**Number of meters multiplied by each class' average meter costs: C12 X C12WMF**	**Metering costs are driven by the number of customers in each class and the respective metering costs.**
C12	Used to calculate C12WM allocator	Reflects actual number of meters. C11 with an adjusted street lighting customer count	
C12WMF	Used to calculate C12WM allocator	Average meter cost for each customer type	
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**

Code	Allocator for:	Derivation	Allocator Rationale & Background
C62Sec	**The "customer" (minimum system) portion of secondary (not primary) distribution line costs**	**Average monthly customers served at secondary voltage. C61PS less primary voltage customers**	**The number of customers served at secondary voltage drives the customer related portion of <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 <u>of 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 as customer related.) Also, transmission and primary voltage customers are excluded since they do not use the secondary distribution system.**

Code	Allocator For	Derivation	Allocator Rationale
D62NLL	**The capacity portion of service-line costs**	**Non-coincident (or "customer peak") demand for secondary voltage customers, less the customer peak demand for street lighting, area lighting and C&I customers served underground**	**Capacity related service line costs are driven by individual customer maximum demands less the minimum system demand of each class. (The minimum system demand is customer related.) Transmission voltage, primary voltage and lighting customers are excluded since they do not cause service related costs. Also excluded are C&I underground customers since they install their own services.**
D10S	**Summer season portion of capacity-related generation costs**	**Each class' % contribution to the single summer system peak. Summer months are June through September.**	**The class contribution to the system summer peak drives the summer portion of capacity-related generation costs.**
D10W	**Winter season portion of capacity-related generation costs**	**Each class' % contribution to the single winter system peak. Winter months are October through May.**	**The class contribution to the system winter peak drives the winter portion of capacity-related generation costs.**
D10T	**Transmission plant costs.**	**Weighted Class Contributions to Summer and Winter Peak loads.** **Allocator equals (D10W% plus (D10S% times 1.2531)) divided by (1 + 1.2531).; The 1.2531 ratio is the ratio of the average summer and winter seasonal system peaks.**	**The driver for transmission costs is class contribution to the summer & winter system peaks. To reflect the fact that summer peaks have more impact, the summer peak contribution for each class is weighted by the ratio of average monthly summer and average monthly winter system peaks.**
D10C	**Capacity-related generation costs.**	**Weighted of Class Contributions to Summer and Winter system peak loads.** **Allocator equals (D10W% plus (D10S% times 2.2301)) divided by (1 + 2.2301). The 2.2301 ratio is obtained from the average summer and winter season peak loads, after subtracting the average annual load from each monthly load.**	**Capacity- related generation costs are driven by class contribution to summer & winter system peaks. To reflect the fact that summer peaks have a disproportionate impact on capacity-related generation costs, the summer peak is weighted by the ratio of average monthly summer and winter system peaks, which are in excess of average annual demand.**

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.**

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**
D56E44	Sales and Economic Development expenses	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. D56E44 = (% Demand Impacts x D10C) + (% Energy Impacts x E8760). $ Energy Impacts = kWh sales x (Base Energy Charge + Fuel Costs – Marginal Energy Costs) $ Demand Impacts = Annual Billing kW x (((4 x Summer Demand Charge)+ (8 x Winter Demand Charge))/12) 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. Total $ Impacts = $ Energy Impacts + $ Demand Impacts	Minn. Stat. §216B.16, subd. 13 (1992) permits the Commission to allow utilities to recover economic development expenses. Pursuant to Docket No: E-002/GR-91-1, the Commission allowed NSP to recover 50% of its economic development expenses. 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.
D42E58	CIP expenses	D48E52 = (.4172 x D10C)+(.5828 x E8760).	CIP program expenses are split between capacity and energy according to whether the purpose of program is to reduce peak load or energy requirements. Once program costs are thus split, the standard capacity and energy allocators are applied to the separate pools of $ expenses.
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.

Code	Allocator for:	Description	Allocator rationale
NEPIS	Property Insurance	Electric plant in service less accumulated provision for depreciation	Property insurance is driven by net electric plant in service
OXDTS	Distribution customer installation expenses and miscellaneous distribution expense.	All Distribution O&M Expense, except Supervision and Engineering, Customer Install and Miscellaneous. Supervision & engineering expenses are excluded since they are an overhead expense. Customer installation expenses and miscellaneous distribution expense are excluded to avoid a circular reference. (lines 2 thru 7, 9 and 11 of page 8)	The OXDTS allocator represents the majority of Distribution O&M expenses (excl supervision and customer installation costs) which is a good indicator for miscellaneous distribution expenses.
OXOPD	Used to allocate Capacity-Related Other Production labor costs	Capacity related "Other Production" expenses: Peaking + Base Load (line 39 of page 7)	Capacity-Related Other Production O&M costs are a good indicator of Capacity-Related Production Other Production labor
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 42 & 43 of page 7 and lines 12-15, 18-21, 32 and 33 of page 8). These A&G expenses are excluded to avoid a circular reference	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.	Total Production Plant: Original Plant in Service (line 6 of page 4)	Total production plant investment is closely associated with Interchange Agreement Capacity related revenues
P10WoN	Interchange Production Capacity (i.e. fixed) inter-company Costs	Total Production Plant less Nuclear Fuel: Original Plant in Service. Nuclear fuel is excluded since NSP Wisconsin does not have nuclear plants (Total Production Plant on line 6 of page 4 less Nuclear Fuel on line 5 of page 4)	Since Wisc. does not have nuclear plants, Total production plant investment less nuclear fuel investment is a good indicator of Interchange Agreement Capacity related expenses
P5161A	Used to allocate Step-up sub transmission 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.
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 Customer-Connection "Services"	Customer-Connection "Services" Original Plant in Service (line 40 of page 4)	Customer-Connection "Services" plant investment drives all costs of Customer-Connection "Services"

Code	Allocator for:	Derivation	Allocator rationale
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 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 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	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 27 thru 47 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. <u>Summary</u> Customer Classes

	Customer Class	Rate Codes	Voltage Specifications
1	Residential	E01, E02, E03, E04, E06, E10 (if residential), E11 (if residential)	
2	C&I Non Demand Metered	E10 (if C&I), E11 (if C&I), E13, E14, E18, E40,	
3	C&I Secondary Voltage	E15, E16, E20, E21, E22	Secondary
4	C&I Primary Voltage	E15, E16, E20, E21, E22	Primary
5	C&I Transmission Transformed Voltage *	E15, E16, E20, E21, E22	Transmission Transformed
6	C&I Transmission Voltage *	E15, E16, E20, E21, E22	Transmission
7	Street Lighting	E12, E30, E31, E32, E33	

B. <u>Detailed</u> Customer Sub-Classes

	Customer Class	Rate Codes	kW Size	Voltage Specifications
1	Residential without Space Heating	E01, E02, E03, E04		
2	Residential with Space Heating	E01, E02, E03, E04		
3	Load Management	E06, E10, E11		
4	Small C&I Non Demand Metered	E13, E14, E18, E40,		
5	Small C&I Secondary Voltage	E15, E16	< 1,000 kW	Secondary
6	Small C&I Primary Voltage	E15, E16	< 1,000 kW	Primary
7	Small C&I Transmission Transformed Voltage *	E15, E16	< 1,000 kW	Transmission Transformed
8	Small C&I Transmission Voltage *	E15, E16	< 1,000 kW	Transmission
9	Large C&I Secondary Voltage	E15, E16	> 1,000 kW	Secondary
10	Large C&I Primary Voltage	E15, E16	> 1,000 kW	Primary
11	Large C&I Transmission Transformed Voltage *	E15, E16	> 1,000 kW	Transmission Transformed
12	Large C&I Transmission Voltage *	E15, E16	> 1,000 kW	Transmission
13	Interruptible All Voltages	E20, E21, E22	> 1,000 kW	All Voltages
14	Street Lighting – Company Owned	E30		
15	Street Lighting – Customer Owned	E31, E32, E33		
16	Auto Protective Lighting	E12		

* Note: Currently there are no Xcel Energy customers in South Dakota that are served at Transmission Transformed or Transmission Voltages

Northern States Power Company, a Minnesota Corporation | **Docket No. EL11-_____**
Electric Utility - South Dakota | **Exhibit _____(MAP-1)**
Test Year Ending December 31, 2010 | **Schedule 3**
Summary of Class Cost of Service Study Results ($000) | **Page 1 of 1**

UNADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 2)	171,754	72,744	9,941	87,402	1,667
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	48	20	3	25	0
[3]	Unadjusted Operating Revenues (line 2 + line 3)	171,802	72,764	9,943	87,427	1,668
[4]	Present Rates (CCOSS page 2, line 3)	157,219	65,967	9,043	80,700	1,508
[5]	Unadjusted Deficiency (line 3 - line 4)	14,583	6,797	900	6,726	160
[6]	Defic / Pres (line 5 / line 4)	9.28%	10.30%	9.95%	8.34%	10.61%
[7]	**Ratio: Class % / Total %**	**1.00**	**1.11**	**1.07**	**0.90**	**1.14**

CAPACITY COST RESPONSIBILITIES FOR INTERRUPTIBLE RATE DISCOUNTS

		Total	Residential	Non-Demand	Demand	Street Ltg
[8]	Interruption Rate Discounts (CCOSS page 2, line 6)	2,691	1,034	23	1,633	0
[9]	Interruption Capacity Costs (CCOSS page 2, line 7)	2,691	1,092	151	1,441	7
[10]	Revenue Requirement Shift (line 9 - line 8)	0	57	127	(192)	7

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[11]	Adjusted Rate Revenue Reqt (line 1 + line 10)	171,754	72,801	10,068	87,210	1,674
[12]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	48	20	3	25	0
[13]	Adjusted Operating Revenues (line 11 + line 12)	171,802	72,821	10,071	87,235	1,675
[14]	Present Rates (line 4)	157,219	65,967	9,043	80,700	1,508
[15]	Adjusted Deficiency (line 13 - line 14)	14,583	6,854	1,027	6,535	167
[16]	Defic / Pres Rates (line 15 / line 4)	9.28%	10.39%	11.36%	8.10%	11.07%
[17]	**Ratio: Class % / Total %**	**1.00**	**1.12**	**1.22**	**0.87**	**1.19**

PROPOSED REVENUE RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[18]	Proposed Rates (CCOSS page 3, line 3)	171,754	72,434	9,975	87,768	1,577
[19]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21+ line 23)	48	20	3	25	0
[20]	Proposed Operating Revenues (line 18 + line 19)	171,802	72,454	9,978	87,793	1,577
[21]	Proposed Increase (line 20 - line 14)	14,583	6,487	934	7,092	69
[22]	Difference / Pres (line 21 / line 14)	9.3%	9.8%	10.3%	8.8%	4.6%
[23]	**Ratio: Class % / Total %**	**1.00**	**1.06**	**1.11**	**0.95**	**0.50**

Northern States Power Company, a Minnesota Corporatior
Electric Utility - State of South Dakota
Test Year Ending December 31, 2010
Class Cost of Service Study Detail

Docket No. EL11-______
Exhibit No. ______(MAP-1)
Schedule 4

Rate Base

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Plant In Service	**Alloc**	**SD**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Production		428,407	157,007	269,474	22,879	246,595	189,027	57,568	0	0	1,926
2	Transmission		97,258	39,293	57,605	5,441	52,164	40,513	11,651	0	0	360
3	Distribution		180,529	119,909	56,084	12,201	43,883	37,338	6,545	0	0	4,536
4	General		17,445	7,811	9,465	1,001	8,464	6,593	1,872	0	0	169
5	Common		23,970	10,733	13,006	1,375	11,630	9,058	2,572	0	0	232
6	TBT Invest		0	0	0	0	0	0	0	0	0	0
7	Total		747,609	334,753	405,634	42,898	362,736	282,529	80,208	0	0	7,222
	Depreciation Reserve											
8	Production		236,656	86,035	149,523	12,591	136,932	104,883	32,048	0	0	1,099
9	Transmission		32,562	13,142	19,300	1,821	17,479	13,573	3,906	0	0	120
10	Distribution		72,025	46,445	22,969	4,637	18,331	15,438	2,893	0	0	2,611
11	General		6,865	3,074	3,725	394	3,331	2,594	737	0	0	66
12	Common		14,938	6,689	8,105	857	7,248	5,645	1,603	0	0	144
13	Total		363,046	155,385	203,621	20,300	183,320	142,134	41,186	0	0	4,041
14	**Net Plant In Service**		384,563	179,368	202,013	22,598	179,416	140,394	39,021	0	0	3,181
	Deductions											
15	Accum Defer Inc Tax		76,523	35,746	40,304	4,446	35,857	28,053	7,805	0	0	473
	Additions											
16	Constr Work In Progress		0	0	0	0	0	0	0	0	0	0
17	Fuel Inventory		4,816	1,694	3,097	252	2,844	2,172	672	0	0	25
18	Materials & Supplies		6,260	2,504	3,715	345	3,370	2,599	771	0	0	41
19	Prepayments		9,855	4,597	5,177	579	4,598	3,598	1,000	0	0	82
20	Non-Plant Assets & Liab		(2,603)	(1,128)	(1,444)	(156)	(1,288)	(999)	(289)	0	0	(31)
21	Working Cash		(2,976)	(1,331)	(1,616)	(174)	(1,442)	(1,128)	(314)	0	0	(29)
22	Total		15,352	6,336	8,927	846	8,082	6,241	1,840	0	0	89
23	**Rate Base**		323,392	149,958	170,637	18,997	151,640	118,583	33,057	0	0	2,797

Income Statement

24A	**Tot Oper Rev - Pres**		196,236	80,366	114,162	11,133	103,029	80,463	22,566	0	0	1,708
24B	**Tot Oper Rev - Prop**		210,819	86,852	122,189	12,067	110,122	86,083	24,038	0	0	1,778
25	Oper & Maint		143,885	56,332	86,386	8,104	78,282	60,193	18,089	0	0	1,167
26	Book Depr + IRS Int		19,769	9,225	10,278	1,159	9,119	7,138	1,982	0	0	266
27	Payroll Tax		1,670	723	927	100	826	641	186	0	0	20
28	Real Est & Prop Tax		5,969	2,670	3,242	349	2,893	2,263	630	0	0	57
29	Deferred Inc Taxes		5,942	1,869	4,032	305	3,727	2,839	888	0	0	41
30A	Present Income Tax		86	797	(727)	33	(760)	(203)	(557)	0	0	16
30B	Proposed Income Tax		5,190	3,068	2,083	360	1,722	1,764	(42)	0	0	40
31	Allow Funds Dur Const		0	0	0	0	0	0	0	0	0	0
32A	**Present Return**		18,914	8,748	10,025	1,083	8,942	7,593	1,349	0	0	142
32B	**Proposed Return**		28,393	12,965	15,242	1,690	13,552	11,246	2,306	0	0	187
33A	**Pres Ret on Rt Base**		5.85%	5.83%	5.87%	5.70%	5.90%	6.40%	4.08%	0.00%	0.00%	5.06%
33B	**Prop Ret on Rt Base**		8.78%	8.65%	8.93%	8.90%	8.94%	9.48%	6.98%	0.00%	0.00%	6.68%
34A	**Pres Ret on Common**		5.41%	5.38%	5.46%	5.13%	5.50%	6.47%	2.04%	0.00%	0.00%	3.91%
34B	**Prop Ret on Common**		10.99%	10.74%	11.29%	11.22%	11.29%	12.34%	7.56%	0.00%	0.00%	6.99%

Northern States Power Company, a Minnesota Corporatior
Electric Utility - State of South Dakota
Test Year Ending December 31, 2010
Class Cost of Service Study Detail

Docket No. EL11-______
Exhibit No. ______(MAP-1)
Schedule 4
Page 2 of 16

PRES vs Equal Rev Reqts

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Total Retail Rev Reqt	**Alloc**	**SD**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**Equal Return On Rate Base**		**8.78%**	**8.78%**	**8.78%**	**8.78%**	**8.78%**	**8.78%**	**8.78%**	**8.78%**	**8.78%**	**8.78%**
2	**UnAdj Equalized Rev Reqt**		**171,754**	**72,744**	**97,343**	**9,941**	**87,402**	**67,660**	**19,742**	**0**	**0**	**1,667**
3	**UnAdj Present Revenue**		**157,219**	**65,967**	**89,744**	**9,043**	**80,700**	**63,343**	**17,358**	**0**	**0**	**1,508**
4	**UnAdj Revenue Deficiency**		**14,535**	**6,776**	**7,599**	**897**	**6,702**	**4,317**	**2,385**	**0**	**0**	**160**
5	**UnAdj Deficiency / Present**		**9.25%**	**10.27%**	**8.47%**	**9.92%**	**8.30%**	**6.82%**	**13.74%**	**0.00%**	**0.00%**	**10.58%**
6	**Interruption Rate Discounts**		**2,691**	**1,034**	**1,656**	**23**	**1,633**	**1,135**	**498**	**0**	**0**	**0**
7	**Interruptible Capacity Costs**	D10C	**2,691**	**1,092**	**1,592**	**151**	**1,441**	**1,117**	**324**	**0**	**0**	**7**
8	**Revenue Shift**		**0**	**57**	**(64)**	**127**	**(192)**	**(18)**	**(174)**	**0**	**0**	**7**
9	**Adj Equal Rev Reqt (Rows 2+8)**		**171,754**	**72,801**	**97,278**	**10,068**	**87,210**	**67,642**	**19,568**	**0**	**0**	**1,674**
10	**Pres Rev (Row 3)**		**157,219**	**65,967**	**89,744**	**9,043**	**80,700**	**63,343**	**17,358**	**0**	**0**	**1,508**
11	**Adj Revenue Deficiency**		**14,535**	**6,834**	**7,535**	**1,025**	**6,510**	**4,300**	**2,211**	**0**	**0**	**166**
12	**Adj Deficiency / Adj Present**		**9.25%**	**10.36%**	**8.40%**	**11.33%**	**8.07%**	**6.79%**	**12.74%**	**0.00%**	**0.00%**	**11.03%**
	Customer Classification											
13	Min Sys & Service Drop		14,686	11,848	1,918	1,241	677	651	26	0	0	920
14	Energy Services		4,822	3,863	917	577	340	333	8	0	0	42
15	Total Customer **(Cusco)**		19,508	15,711	2,835	1,818	1,017	984	34	0	0	962
16	Ave Monthly Customers		84,731	72,360	10,446	7,340	3,106	3,046	60	0	0	1,925
17	Svc Drop Reqt	$ / Mo / Cust	$14.44	$13.64	$15.30	$14.09	$18.16	$17.82	$35.63	$0.00	$0.00	$39.81
18	Ener Svcs Reqt	$ / Mo / Cust	$4.74	$4.45	$7.32	$6.55	$9.13	$9.10	$10.84	$0.00	$0.00	$1.82
19	Total Reqt	$ / Mo / Cust	$19.19	$18.09	$22.62	$20.64	$27.30	$26.92	$46.47	$0.00	$0.00	$41.63
	Energy Classification											
20	On Peak Rev Reqt		41,821	13,406	28,320	2,439	25,881	20,081	5,800	0	0	95
21	Off Peak Rev Reqt		37,401	14,465	22,618	1,713	20,905	15,647	5,258	0	0	319
22	Total Ener Rev Reqt		79,222	27,871	50,938	4,151	46,786	35,728	11,058	0	0	414
23	Annual MWh Sales		1,985,982	685,877	1,286,603	100,682	1,185,921	892,226	293,695	0	0	13,502
24	On Pk Reqt	Mills / kWh	21.058	19.546	22.011	24.223	21.823	22.506	19.749	0.000	0.000	7.045
25	Off Pk Reqt	Mills / kWh	18.833	21.089	17.580	17.010	17.628	17.537	17.904	0.000	0.000	23.592
26	Total Reqt	Mills / kWh	39.891	40.635	39.591	41.233	39.451	40.043	37.653	0.000	0.000	30.637
	Demand Classification											
27	Energy-Related Prod		17,179	6,046	11,043	900	10,143	7,746	2,396	0	0	90
28	Capacity-Related Summer Peak Prod		19,429	7,706	11,723	1,100	10,623	8,176	2,447	0	0	0
29	Capacity-Related Winter Peak Prod		8,712	3,713	4,927	478	4,449	3,507	942	0	0	72
30	Total Production		45,321	17,466	27,693	2,479	25,215	19,430	5,785	0	0	162
31	Transmission **(Transco)**		15,869	6,432	9,379	889	8,489	6,598	1,891	0	0	58
32	Primary Dist Subs		3,612	1,457	2,126	193	1,934	1,468	466	0	0	29
33	Prim Dist Lines		3,842	1,426	2,393	184	2,208	1,701	507	0	0	23
34	Second Dist, Trans		4,380	2,382	1,979	226	1,752	1,752	0	0	0	19
35	Total Distribution **(Disco)**		11,834	5,265	6,498	604	5,894	4,920	974	0	0	72
36	Total Demand Rev Reqt		73,024	29,162	43,570	3,971	39,598	30,948	8,650	0	0	292
37	Annual Billing kW		3,150,684	0	3,150,684	0	3,150,684	2,544,887	605,796	0	0	0
38	Base Rev Reqt	$ / kW	$0.00	$0.00	$3.50	$0.00	$3.22	$3.04	$3.96	$0.00	$0.00	$0.00
39	Summer Rev Reqt	$ / kW	$0.00	$0.00	$3.72	$0.00	$3.37	$3.21	$4.04	$0.00	$0.00	$0.00
40	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.56	$0.00	$1.41	$1.38	$1.56	$0.00	$0.00	$0.00
41	Prod Rev Reqt	$ / kW	$0.00	$0.00	$8.79	$0.00	$8.00	$7.63	$9.55	$0.00	$0.00	$0.00
42	Tran Rev Reqt	$ / kW	$0.00	$0.00	$2.98	$0.00	$2.69	$2.59	$3.12	$0.00	$0.00	$0.00
43	Dist Rev Reqt	$ / kW	$0.00	$0.00	$2.06	$0.00	$1.87	$1.93	$1.61	$0.00	$0.00	$0.00
44	Tot Dmd Rev Reqt		$0.00	$0.00	$13.83	$0.00	$12.57	$12.16	$14.28	$0.00	$0.00	$0.00
45	Tot Dmd Rev Reqt	Mills / kWh	36.770	42.518	33.864	39.446	33.390	34.686	29.453	0.000	0.000	21.626
				0.00								
46	Summer Billing kW		1,201,805	0	1,201,805	0	1,201,805	965,023	236,782	0	0	0
47	Winter Billing kW		1,948,879	0	1,948,879	0	1,948,879	1,579,864	369,015	0	0	0
48	Tot Summer Reqt	$ / kW	$0.00	$0.00	$18.30	$0.00	$16.62	$16.04	$19.02	$0.00	$0.00	$0.00
49	Tot Winter Reqt	$ / kW	$0.00	$0.00	$11.07	$0.00	$10.07	$9.79	$11.24	$0.00	$0.00	$0.00
50	Energy + Production **(Genco)**		124,543	45,336	78,631	6,630	72,001	55,157	16,844	0	0	575

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of South Dakota
Test Year Ending December 31, 2010
Class Cost of Service Study Detail

Docket No. EL11-______
Exhibit No. ______(MAP-1)
Schedule 4

PROP vs Equal Rev Reqts

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Total Retail Rev Reqt	**Alloc**	**SD**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**Proposed Ret On Rt Base**		**8.78%**	**8.65%**	**8.93%**	**8.90%**	**8.94%**	**9.48%**	**6.98%**	**0.00%**	**0.00%**	**6.68%**
2	**UnAdj Equalized Rev Reqt**		**171,754**	**72,744**	**97,343**	**9,941**	**87,402**	**67,660**	**19,742**	**0**	**0**	**1,667**
3	**UnAdj Proposed Revenue**		**171,754**	**72,434**	**97,743**	**9,975**	**87,768**	**68,944**	**18,825**	**0**	**0**	**1,577**
4	**UnAdj Revenue Deficiency**		**(0)**	**310**	**(401)**	**(34)**	**(366)**	**(1,284)**	**918**	**0**	**0**	**90**
5	**UnAdj Deficiency / Proposed**		**0.00%**	**0.43%**	**-0.41%**	**-0.34%**	**-0.42%**	**-1.86%**	**4.88%**	**0%**	**0%**	**5.74%**
6	**Interruption Rate Discounts**		**2,691**	**1,034**	**1,656**	**23**	**1,633**	**1,135**	**498**	**0**	**0**	**0**
7	**Interruptible Capacity Costs**	**D10C**	**2,691**	**1,092**	**1,592**	**151**	**1,441**	**1,117**	**324**	**0**	**0**	**7**
8	**Revenue Shift**		**0**	**57**	**(64)**	**127**	**(192)**	**(18)**	**(174)**	**0**	**0**	**7**
9	**Adj Equal Rev (Rows 2+8)**		**171,754**	**72,801**	**97,278**	**10,068**	**87,210**	**67,642**	**19,568**	**0**	**0**	**1,674**
10	**Prop Rev (Row 3)**		**171,754**	**72,434**	**97,743**	**9,975**	**87,768**	**68,944**	**18,825**	**0**	**0**	**1,577**
11	**Adj Revenue Deficiency**		**(0)**	**367**	**(465)**	**93**	**(558)**	**(1,301)**	**744**	**0**	**0**	**97**
12	**Adj Deficiency / Adj Prop**		**0.00%**	**0.51%**	**-0.48%**	**0.93%**	**-0.64%**	**-1.89%**	**3.95%**	**0.00%**	**0.00%**	**6.17%**
	Customer Component											
13	Min Sys & Service Drop		14,686	9,101	4,834	1,063	3,771	3,177	594	0	0	751
14	Energy Services		4,822	3,867	913	577	336	329	7	0	0	42
15	Total Customer **(Cusco)**		19,508	12,968	5,747	1,640	4,107	3,506	601	0	0	793
16	Ave Monthly Customers		84,731	72,360	10,446	7,340	3,106	3,046	60	0	0	1,925
17	Svc Drop Reqt	$ / Mo / Cust	$14.44	$10.48	$38.57	$12.07	$101.19	$86.93	$824.10	$0.00	$0.00	$32.49
18	Ener Svcs Reqt	$ / Mo / Cust	$4.74	$4.45	$7.28	$6.55	$9.01	$9.00	$9.64	$0.00	$0.00	$1.82
19	Total Reqt	$ / Mo / Cust	$19.19	$14.93	$45.85	$18.62	$110.20	$95.93	$833.73	$0.00	$0.00	$34.31
	Energy Component											
20	On Peak Rev Reqt		41,821	13,445	28,279	2,439	25,840	20,056	5,784	0	0	96
21	Off Peak Rev Reqt		37,401	14,483	22,601	1,716	20,884	15,642	5,243	0	0	318
22	Total Ener Rev Reqt		79,222	27,928	50,880	4,155	46,725	35,698	11,027	0	0	414
23	Annual MWh Sales		1,985,982	685,877	1,286,603	100,682	1,185,921	892,226	293,695	0	0	13,502
24	On Pk Reqt	Mills / kWh	21.058	19.603	21.980	24.227	21.789	22.479	19.693	0.000	0.000	7.137
25	Off Pk Reqt	Mills / kWh	18.833	21.115	17.566	17.045	17.610	17.531	17.852	0.000	0.000	23.555
26	Total Reqt	Mills / kWh	39.891	40.718	39.546	41.272	39.399	40.010	37.545	0.000	0.000	30.692
	Demand Component											
27	Base Load Prod		17,179	7,638	9,430	1,009	8,422	6,912	1,510	0	0	110
28	Summer Peak Prod		19,429	8,043	11,350	1,117	10,233	8,037	2,196	0	0	37
29	Winter Peak Prod		8,712	3,790	4,855	490	4,365	3,491	874	0	0	68
30	Total Production		45,321	19,471	25,635	2,615	23,020	18,440	4,580	0	0	215
31	Transmission **(Transco)**		15,869	6,809	8,980	915	8,065	6,454	1,612	0	0	80
32	Primary Dist Subs		3,612	1,549	2,037	203	1,833	1,452	382	0	0	27
33	Prim Dist Lines		3,842	1,544	2,275	200	2,074	1,637	438	0	0	24
34	Second Dist, Trans		4,380	2,166	2,189	246	1,943	1,757	186	0	0	24
35	Total Distribution **(Disco)**		11,834	5,259	6,500	650	5,851	4,845	1,005	0	0	75
36	Total Demand Rev Reqt		73,024	31,538	41,116	4,179	36,936	29,739	7,197	0	0	370
37	Annual Billing kW		3,150,684	0	3,150,684	0	3,150,684	2,544,887	605,796	0	0	0
38	Base Rev Reqt	$ / kW	$0.00	$0.00	$2.99	$0.00	$2.67	$2.72	$2.49	$0.00	$0.00	$0.00
39	Summer Rev Reqt	$ / kW	$0.00	$0.00	$3.60	$0.00	$3.25	$3.16	$3.62	$0.00	$0.00	$0.00
40	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.54	$0.00	$1.39	$1.37	$1.44	$0.00	$0.00	$0.00
41	Prod Rev Reqt	$ / kW	$0.00	$0.00	$8.14	$0.00	$7.31	$7.25	$7.56	$0.00	$0.00	$0.00
42	Tran Rev Reqt	$ / kW	$0.00	$0.00	$2.85	$0.00	$2.56	$2.54	$2.66	$0.00	$0.00	$0.00
43	Dist Rev Reqt	$ / kW	$0.00	$0.00	$2.06	$0.00	$1.86	$1.90	$1.66	$0.00	$0.00	$0.00
44	Tot Dmd Rev Reqt		$0.00	$0.00	$13.05	$0.00	$11.72	$11.69	$11.88	$0.00	$0.00	$0.00
45	Tot Dmd Rev Reqt	Mills / kWh	36.770	45.983	31.957	41.512	31.146	33.332	24.504	0.000	0.000	27.398
46	Summer Billing kW		1,201,805	0	1,201,805	0	1,201,805	965,023	236,782	0	0	0
47	Winter Billing kW		1,948,879	0	1,948,879	0	1,948,879	1,579,864	369,015	0	0	0
48	Tot Summer Reqt	$ / kW	$0.00	$0.00	$17.35	$0.00	$15.60	$15.48	$16.09	$0.00	$0.00	$0.00
49	Tot Winter Reqt	$ / kW	$0.00	$0.00	$10.40	$0.00	$9.33	$9.37	$9.18	$0.00	$0.00	$0.00
50	Energy + Production **(Genco)**		124,543	47,398	76,515	6,770	69,745	54,138	15,606	0	0	629
51	Prop Rev - Pres Rev (Pg 2)		14,535	6,466	8,000	932	7,068	5,601	1,467	0	0	69
52	Difference / Present		9.25%	9.80%	8.91%	10.30%	8.76%	8.84%	8.45%	0.00%	0.00%	4.58%
53	Adj Prop - Adj Pres (Pg 2)		14,535	6,466	8,000	932	7,068	5,601	1,467	0	0	69
54	Difference / Adj Present		9.25%	9.80%	8.91%	10.30%	8.76%	8.84%	8.45%	0.00%	0.00%	4.58%

Original Plant in Service

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**SD**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Summer Peak	D10S	80,524	31,936	48,588	4,560	44,028	33,885	10,143	0	0	0
2	WInter Peak	D10W	36,108	15,388	20,422	1,980	18,441	14,536	3,905	0	0	298
3	Total Peak	[D10C]	116,632	47,323	69,010	6,541	62,469	48,422	14,048	0	0	298
4	Base Load	E8760	217,323	76,455	139,733	11,388	128,345	98,009	30,336	0	0	1,135
5	Nuclear Fuel	E8760	94,452	33,229	60,730	4,950	55,781	42,596	13,184	0	0	493
6	Total		428,407	157,007	269,474	22,879	246,595	189,027	57,568	0	0	1,926
	Transmission											
7	Gen Step Up Base	E8760	2,235	786	1,437	117	1,320	1,008	312	0	0	12
8	Gen Step Up Peak	D10C	1,199	486	709	67	642	498	144	0	0	3
9	Total Gen Step Up		3,434	1,273	2,146	184	1,962	1,506	456	0	0	15
10	Bulk Transmission	D10T	93,651	37,955	55,353	5,248	50,105	38,940	11,164	0	0	344
11	Distrib Function	D60Sub	162	66	95	9	86	66	20	0	0	1
12	Direct Assign	Dir Assign	11	0	11	0	11	0	11	0	0	0
13	Total		97,258	39,293	57,605	5,441	52,164	40,513	11,651	0	0	360
	Distribution:											
	Substations											
14	Generat Step Up	STRATH	198	71	126	10	115	88	27	0	0	1
15	Bulk Transmission	D10T	95	39	56	5	51	40	11	0	0	0
16	Distrib Function	D60Sub	25,420	10,345	14,867	1,369	13,498	10,425	3,073	0	0	208
17	Direct Assign	Dir Assign	250	0	250	0	250	0	250	0	0	0
18	Total		25,963	10,455	15,299	1,385	13,914	10,553	3,361	0	0	209
	Overhead Lines											
19	Primary Capacity	D61PS	17,375	6,449	10,820	834	9,986	7,691	2,295	0	0	106
20	Primary Customer	C61PS	12,715	11,059	1,599	1,123	476	467	9	0	0	58
21	Total Primary		30,090	17,508	12,418	1,957	10,462	8,158	2,304	0	0	163
22	Second Capacity	D62SecL	6,574	3,351	3,190	362	2,828	2,828	0	0	0	33
23	Second Customer	C62Sec	8,009	6,971	1,002	708	294	294	0	0	0	36
24	Total Secondary		14,583	10,322	4,192	1,069	3,123	3,123	0	0	0	69
25	Street Lighting	DASL	1,740	0	0	0	0	0	0	0	0	1,740
26	Total		46,413	27,830	16,610	3,026	13,584	11,280	2,304	0	0	1,972
	Underground Lines											
27	Primary Capacity	D61PS	5,101	1,893	3,177	245	2,932	2,258	674	0	0	31
28	Primary Customer	C61PS	31,124	27,070	3,913	2,748	1,165	1,143	23	0	0	141
29	Total Primary		36,225	28,963	7,089	2,993	4,097	3,400	696	0	0	172
30	Second Capacity	D62SecL	14,235	7,257	6,908	783	6,124	6,124	0	0	0	71
31	Second Customer	C62Sec	16,924	14,730	2,117	1,495	622	622	0	0	0	77
32	Total Secondary		31,159	21,987	9,025	2,279	6,746	6,746	0	0	0	147
33	Total		67,384	50,950	16,114	5,271	10,843	10,147	696	0	0	319
	Line Transformers											
34	Primary	D61PS	715	265	445	34	411	316	94	0	0	4
35	Second Capacity	D62SecL	6,465	3,296	3,137	356	2,782	2,782	0	0	0	32
36	Second Customer	C62Sec	6,155	5,357	770	544	226	226	0	0	0	28
37	Total		13,335	8,918	4,352	934	3,419	3,324	94	0	0	64
	Services											
38	Second Capacity	D62NLL	5,450	4,397	1,053	142	911	911	0	0	0	0
39	Second Customer	C62NL	14,490	13,500	990	699	291	291	0	0	0	0
40	Total		19,940	17,897	2,043	841	1,202	1,202	0	0	0	0
41	Meters	C12WM	5,553	3,858	1,666	745	921	832	89	0	0	30
42	Street Lighting	Dir Assign	1,941	0	0	0	0	0	0	0	0	1,941
43	**Total Distribution**		180,529	119,909	56,084	12,201	43,883	37,338	6,545	0	0	4,536
44	**General Plant**	PTD	17,445	7,811	9,465	1,001	8,464	6,593	1,872	0	0	169
45	**Electric Common**	PTD	23,970	10,733	13,006	1,375	11,630	9,058	2,572	0	0	232
46	Prelim Elec Plant		747,609	334,753	405,634	42,898	362,736	282,529	80,208	0	0	7,222
47	TBT Investment	NEPIS	0	0	0	0	0	0	0	0	0	0
48	**Elec Plant in Serv**		747,609	334,753	405,634	42,898	362,736	282,529	80,208	0	0	7,222

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of South Dakota
Test Year Ending December 31, 2010
Class Cost of Service Study Detail

Docket No. EL11-______
Exhibit No. ______(MAP-1)
Schedule 4

Accum Deprec; Net Plant

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**SD**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10C	51,507	20,899	30,476	2,889	27,588	21,384	6,204	0	0	132
2	Decom Int Peaking	D10C	0	0	0	0	0	0	0	0	0	0
3	Decom Int Baseload	E8760	0	0	0	0	0	0	0	0	0	0
2	Nuclear Fuel	E8760	83,227	29,280	53,513	4,361	49,152	37,534	11,618	0	0	435
3	Base Load	E8760	101,922	35,856	65,533	5,341	60,192	45,965	14,227	0	0	532
4	Total		236,656	86,035	149,523	12,591	136,932	104,883	32,048	0	0	1,099
	Transmission											
5	Gen Step Up Base	E8760	1,007	354	647	53	595	454	141	0	0	5
6	Gen Step Up Peak	D10C	541	220	320	30	290	225	65	0	0	1
7	Total Gen Step Up		1,548	574	968	83	884	679	206	0	0	7
8	Bulk Transmission	D10T	31,011	12,568	18,329	1,738	16,591	12,894	3,697	0	0	114
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	3	0	3	0	3	0	3	0	0	0
11	Total		32,562	13,142	19,300	1,821	17,479	13,573	3,906	0	0	120
	Distribution											
12	Generat Step Up	STRATH	84	30	53	4	49	37	11	0	0	0
13	Bulk Transmission	D10T	37	15	22	2	20	15	4	0	0	0
14	Distrib Function	D60Sub	10,595	4,312	6,197	570	5,626	4,345	1,281	0	0	87
15	Direct Assign	Dir Assign	105	0	105	0	105	0	105	0	0	0
16	Total Substations		10,821	4,357	6,377	577	5,800	4,398	1,402	0	0	87
17	Overhead Lines	POL	24,876	14,916	8,903	1,622	7,281	6,046	1,235	0	0	1,057
18	Underground	PUL	18,838	14,244	4,505	1,474	3,031	2,837	195	0	0	89
19	Line Transformers	P68	5,609	3,751	1,831	393	1,438	1,398	40	0	0	27
20	Services	P69	9,151	8,213	938	386	552	552	0	0	0	0
21	Meters	C12WM	1,387	964	416	186	230	208	22	0	0	7
22	Street Lighting	P73	1,343	0	0	0	0	0	0	0	0	1,343
23	Total		72,025	46,445	22,969	4,637	18,331	15,438	2,893	0	0	2,611
24	**General Plant**	PTD	6,865	3,074	3,725	394	3,331	2,594	737	0	0	66
25	**Electric Common**	PTD	14,938	6,689	8,105	857	7,248	5,645	1,603	0	0	144
26	**Total Accum Depr**		363,046	155,385	203,621	20,300	183,320	142,134	41,186	0	0	4,041
27	**Net Elec Plant**		384,563	179,368	202,013	22,598	179,416	140,394	39,021	0	0	3,181

Subtractions: Accum Defer Inc Tax

			SD	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
	Production											
28	Peaking Plant	D10C	11,177	4,535	6,613	627	5,986	4,640	1,346	0	0	29
29	Base Load	E8760	29,057	10,222	18,683	1,523	17,160	13,104	4,056	0	0	152
30	Nuclear Fuel	E8760	832	293	535	44	491	375	116	0	0	4
31	Total		41,066	15,050	25,831	2,193	23,638	18,120	5,518	0	0	185
	Transmission											
32	Gen Step Up Base	E8760	325	114	209	17	192	147	45	0	0	2
33	Gen Step Up Peak	D10C	174	71	103	10	93	72	21	0	0	0
34	Total Gen Step Up		499	185	312	27	285	219	66	0	0	2
35	Bulk Transmission	D10T	12,537	5,081	7,410	703	6,707	5,213	1,495	0	0	46
36	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
37	Direct Assign	Dir Assign	2	0	2	0	2	0	2	0	0	0
38	Total		13,038	5,266	7,724	729	6,995	5,432	1,563	0	0	48
	Distribution											
39	Generat Step Up	STRATH	39	14	25	2	23	17	5	0	0	0
40	Bulk Transmission	D10T	13	5	8	1	7	5	2	0	0	0
41	Distrib Function	D60Sub	3,580	1,457	2,094	193	1,901	1,468	433	0	0	29
42	Direct Assign	Dir Assign	18	0	18	0	18	0	18	0	0	0
43	Total Substations		3,650	1,476	2,144	196	1,949	1,491	458	0	0	30
44	Overhead Lines	POL	5,774	3,462	2,066	376	1,690	1,403	287	0	0	245
45	Underground	PUL	8,784	6,642	2,101	687	1,413	1,323	91	0	0	42
46	Line Transformers	P68	2,051	1,372	669	144	526	511	15	0	0	10
47	Services	P69	3,089	2,773	316	130	186	186	0	0	0	0
48	Meters	C12WM	630	438	189	84	105	94	10	0	0	3
49	Street Lighting	P73	(79)	0	0	0	0	0	0	0	0	(79)
50	Total		23,899	16,162	7,486	1,618	5,869	5,009	860	0	0	251
51	**General Plant**	PTD	2,023	906	1,098	116	982	765	217	0	0	20
52	**Electric Common**	PTD	1,911	856	1,037	110	927	722	205	0	0	18
53	**Total Deferred Tax**		81,937	38,240	43,176	4,766	38,410	30,047	8,363	0	0	522
54	Net Operating Loss (NOL) Carry Forwa	NEPIS	(4,470)	(2,085)	(2,348)	(263)	(2,085)	(1,632)	(454)	0	0	(37)
55	Non-Plant Related	LABOR	(944)	(409)	(524)	(57)	(467)	(362)	(105)	0	0	(11)
56	**Accum Def W/ Adj**		76,523	35,746	40,304	4,446	35,857	28,053	7,805	0	0	473

Additions: CWIP, Etc; Rate Base

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	CWIP											
	Production	**Alloc**	**SD**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10C	0	0	0	0	0	0	0	0	0	0
2	Base Load	E8760	0	0	0	0	0	0	0	0	0	0
3	Nuclear Fuel	E8760	0	0	0	0	0	0	0	0	0	0
4	Total		0	0	0	0	0	0	0	0	0	0
	Transmission											
5	Gen Step Up Base	E8760	0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10C	0	0	0	0	0	0	0	0	0	0
7	Total Gen Step Up		0	0	0	0	0	0	0	0	0	0
8	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
11	Total		0	0	0	0	0	0	0	0	0	0
	Distribution											
12	Generat Step Up	STRATH	0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
16	Total Substations		0	0	0	0	0	0	0	0	0	0
17	Overhead Lines	POL	0	0	0	0	0	0	0	0	0	0
18	Underground	PUL	0	0	0	0	0	0	0	0	0	0
19	Line Transformers	P68	0	0	0	0	0	0	0	0	0	0
20	Services	P69	0	0	0	0	0	0	0	0	0	0
21	Meters	C12WM	0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73	0	0	0	0	0	0	0	0	0	0
23	Total		0	0	0	0	0	0	0	0	0	0
24	**General Plant**	PTD	0	0	0	0	0	0	0	0	0	0
25	**Electric Common**	PTD	0	0	0	0	0	0	0	0	0	0
26	**Total CWIP**		0	0	0	0	0	0	0	0	0	0
27	Fuel Inventory	E8760	4,816	1,694	3,097	252	2,844	2,172	672	0	0	25
	Materials & Supplies											
28	Production	P10	5,245	1,922	3,299	280	3,019	2,314	705	0	0	24
29	Trans & Distr	TD	1,015	582	415	64	351	284	66	0	0	18
30	Total		6,260	2,504	3,715	345	3,370	2,599	771	0	0	41
	Prepayments											
31	Miscellaneous	NEPIS	9,855	4,597	5,177	579	4,598	3,598	1,000	0	0	82
32	Fuel	E8760	0	0	0	0	0	0	0	0	0	0
33	Insurance	NEPIS	0	0	0	0	0	0	0	0	0	0
32	Total		9,855	4,597	5,177	579	4,598	3,598	1,000	0	0	82
33	Non-Plant Assets & Liab	LABOR	(2,603)	(1,128)	(1,444)	(156)	(1,288)	(999)	(289)	0	0	(31)
34	Working Cash	PT0	(2,976)	(1,331)	(1,616)	(174)	(1,442)	(1,128)	(314)	0	0	(29)
35	**Total Additions**		15,352	6,336	8,927	846	8,082	6,241	1,840	0	0	89
36	**Total Rate Base**		323,392	149,958	170,637	18,997	151,640	118,583	33,057	0	0	2,797
37	**Common Rate Base (@ 52.48%)**		169,716.1	78,698	89,550	9,970	79,581	62,232	17,348	0	0	1,468

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of South Dakota
Test Year Ending December 31, 2010
Class Cost of Service Study Detail

Operating Rev (Cal Month)

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Retail Revenue	**Alloc**	**SD**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Present Rate Revenue	R01; (calc)	157,219	65,967	89,744	9,043	80,700	63,343	17,358	0	0	1,508
2	Proposed Rate Revenue	PROREV; (calc	171,754	72,434	97,743	9,975	87,768	68,944	18,825	0	0	1,577
	Other Retail Revenue											
3	Interdepartmental	R01; R02	0	0	0	0	0	0	0	0	0	0
4	Gross Earnings Tax	R01; R02	0	0	0	0	0	0	0	0	0	0
5	CIP Adjustment to Program Costs	D42E58	**0**	0	0	0	0	0	0	0	0	0
6	**Tot Other Retail Rev**		0	0	0	0	0	0	0	0	0	0
	Other Operating Revenue											
7	Interchg Prod Capacity	P10	9,883	3,622	6,217	528	5,689	4,361	1,328	0	0	44
8	Interchg Prod Energy	E8760	11,106	3,907	7,141	582	6,559	5,009	1,550	0	0	58
9	Interchg Tr Bulk Supply	D10T	2,228	903	1,317	125	1,192	926	266	0	0	8
10	Interchg Decomm		0	0	0	0	0	0	0	0	0	0
10	Dist Int Sales; Oth Serv	E8760	0	0	0	0	0	0	0	0	0	0
11	Dist Overhd Line Rent	POL	243	146	87	16	71	59	12	0	0	10
12	Connection Charges	C11	256	219	32	22	9	9	0	0	0	6
13	Sales For Resale	E8760	10,891	3,831	7,003	571	6,432	4,912	1,520	0	0	57
14	Joint Op Agree-Other PSCo Rev	D10T	(633)	(257)	(374)	(35)	(339)	(263)	(75)	0	0	(2)
15	Production Assoc'd Rev	E8760	316	111	203	17	187	143	44	0	0	2
16	Misc Ancillary Trans Rev	D10T	3,951	1,601	2,335	221	2,114	1,643	471	0	0	14
17	MISO	D10T	585	237	346	33	313	243	70	0	0	2
18	Other	D10T	191	77	113	11	102	79	23	0	0	1
19	Late Pay Chg - Pres	R16C; R02	0.0000	0	0	0	0	0	0	0	0	0
20	**Tot Other Op - Pres**		39,017	14,398	24,418	2,089	22,329	17,120	5,209	0	0	200
21	Incr Misc Serv - Prop	R01,	48	20	27	3	25	19	5	0	0	0
22	Incr Inter Departmental - Prop	R01; R02	0	0	0	0	0	0	0	0	0	0
23	Incr Late Pay - Prop	(R16C); R02	0	0	0	0	0	0	0	0	0	0
24	**Tot Other Op - Prop**		39,065	14,418	24,446	2,092	22,354	17,140	5,214	0	0	201
25	**Tot Oper Rev - Pres**		196,236	80,366	114,162	11,133	103,029	80,463	22,566	0	0	1,708
26	**Tot Oper Rev - Prop**		210,819	86,852	122,189	12,067	110,122	86,083	24,038	0	0	1,778

Operating & Maint (Pg 1 of 2)

			SD	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
	Production Expen											
27	**Fuel**	E8760	22,528	7,925	14,485	1,181	13,304	10,160	3,145	0	0	118
	Purchased Power											
28	Purchases: Cap Peak	D10C	7,040	2,856	4,166	395	3,771	2,923	848	0	0	18
29	Purchases: Cap Base	E8760	2,717	956	1,747	142	1,605	1,225	379	0	0	14
30	Purchases: Demand		9,757	3,812	5,912	537	5,375	4,148	1,227	0	0	32
31	Purchases: Other Energy	E8760	38,274	13,465	24,609	2,006	22,604	17,261	5,343	0	0	200
32	Tot Non-Assoc Purch		48,031	17,277	30,522	2,543	27,979	21,409	6,570	0	0	232
33	Interchg Agr Capacity	P10WoN	2,624	973	1,640	141	1,499	1,151	349	0	0	11
34	Interchg Agr Energy	E8760	9,501	3,342	6,109	498	5,611	4,285	1,326	0	0	50
35	Tot Wis Interchg Purch		12,125	4,315	7,749	639	7,110	5,435	1,675	0	0	61
36	**Tot Purchased Power**		60,156	21,592	38,271	3,182	35,089	26,844	8,245	0	0	293
	Other Production											
37	Capacity Related	D10C	7,580	3,076	4,485	425	4,060	3,147	913	0	0	19
38	Energy Related	E8760	20,261	7,128	13,027	1,062	11,966	9,137	2,828	0	0	106
39	Total Other Produc		27,841	10,203	17,512	1,487	16,026	12,284	3,741	0	0	125
40	**Total Production**		110,525	39,721	70,268	5,849	64,419	49,289	15,131	0	0	536
41	**Transmission Exp**	D10T	9,754	3,953	5,765	547	5,219	4,056	1,163	0	0	36

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of South Dakota
Test Year Ending December 31, 2010
Class Cost of Service Study Detail

Operating & Maint (Pg 2 of 2)

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Distribution Expen	**Alloc**	**SD**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Supervision & Eng'rg	ZDTS	893	540	311	64	246	205	42	0	0	42
2	Load Dispatching	D10T	260	105	154	15	139	108	31	0	0	1
3	Substations	P61	610	246	359	33	327	248	79	0	0	5
4	Overhead Lines	POL	1,761	1,056	630	115	515	428	87	0	0	75
5	Underground Lines	PUL	1,311	991	314	103	211	197	14	0	0	6
6	Line Transformers	P68	3	2	1	0	1	1	0	0	0	0
7	Meters	C12WM	247	172	74	33	41	37	4	0	0	1
8	Customer Install'n	OXDTS	115	67	40	8	32	27	6	0	0	8
9	Street Lighting	Dir Assign	216	0	0	0	0	0	0	0	0	216
10	Miscellaneous	OXDTS	816	477	284	55	229	189	40	0	0	56
11	Rents (Pole Attachmts)	POL	165	99	59	11	48	40	8	0	0	7
12	**Total Distribution**		6,397	3,754	2,225	436	1,790	1,480	310	0	0	417
13	**Customer Accounting**	C11WA	3,996	3,189	775	485	290	283	7	0	0	32
14	**Sales, Econ Dvlp & Other**	D56E44	53	20	33	3	30	23	7	0	0	0
	Admin & General											
15	Salaries	LABOR	3,426	1,484	1,901	206	1,695	1,315	381	0	0	41
16	Office Supplies	OXTS	2,317	907	1,391	130	1,261	969	291	0	0	19
17	Admin Transfer Credit	OXTS	(892)	(349)	(536)	(50)	(485)	(373)	(112)	0	0	(7)
18	Outside Services	LABOR	761	330	422	46	377	292	85	0	0	9
19	Property Insurance	NEPIS	469	219	246	28	219	171	48	0	0	4
20	Pensions & Benefits	LABOR	4,277	1,853	2,373	257	2,116	1,641	475	0	0	51
21	Injuries & Claims	LABOR	815	353	452	49	403	313	91	0	0	10
22	Regulatory Exp	R01; R02	370	155	211	21	190	149	41	0	0	4
23	General Advertising	OXTS	(14)	(5)	(8)	(1)	(8)	(6)	(2)	0	0	(0)
24	Contributions	OXTS	0	0	0	0	0	0	0	0	0	0
25	Misc General Exp	OXTS	(78)	(31)	(47)	(4)	(42)	(33)	(10)	0	0	(1)
26	Rents	OXTS	855	335	513	48	465	358	108	0	0	7
27	Maint of General Plant	OXTS	28	11	17	2	15	12	4	0	0	0
28	Total		12,334	5,261	6,937	731	6,206	4,808	1,399	0	0	136
	Cust Service & Info											
29	Cust Assist Exp - Non-CIP	C11P10	146	89	55	10	45	35	10	0	0	2
30	CIP Total	D42E58	0	0	0	0	0	0	0	0	0	0
31	Instructional Advertising	C11P10	278	170	105	19	85	66	19	0	0	4
32	Total		424	259	159	30	130	101	29	0	0	6
33	Amortizations	LABOR	402	174	223	24	199	154	45	0	0	5
34	**Total O&M Expense**		143,885	56,332	86,386	8,104	78,282	60,193	18,089	0	0	1,167

Book Depreciation

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**SD**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10C	3,383	1,373	2,002	190	1,812	1,405	408	0	0	9
2	Base Load	E8760	5,719	2,012	3,677	300	3,377	2,579	798	0	0	30
3	Total		9,102	3,385	5,679	489	5,189	3,984	1,206	0	0	39
	Transmission											
4	Gen Step Up Base	E8760	57	20	37	3	34	26	8	0	0	0
5	Gen Step Up Peak	D10C	30	12	18	2	16	12	4	0	0	0
6	Total Gen Step Up		87	32	54	5	50	38	12	0	0	0
7	Bulk Transmission	D10T	2,404	974	1,421	135	1,286	1,000	287	0	0	9
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		2,491	1,007	1,475	139	1,336	1,038	298	0	0	9
	Distribution											
11	Generat Step Up	STRATH	6	2	4	0	3	3	1	0	0	0
12	Bulk Transmission	D10T	3	1	2	0	2	1	0	0	0	0
13	Distrib Function	D60Sub	731	297	428	39	388	300	88	0	0	6
14	Direct Assign	Dir Assign	7	0	7	0	7	0	7	0	0	0
15	Total Substations		747	301	440	40	400	304	97	0	0	6
16	Overhead Lines	POL	2,006	1,203	718	131	587	488	100	0	0	85
17	Underground	PUL	1,513	1,144	362	118	243	228	16	0	0	7
18	Line Transformers	P68	387	259	126	27	99	96	3	0	0	2
19	Services	P69	673	604	69	28	41	41	0	0	0	0
20	Meters	C12WM	358	249	107	48	59	54	6	0	0	2
21	Street Lighting	P73	93	0	0	0	0	0	0	0	0	93
22	Total		5,777	3,759	1,822	392	1,430	1,210	220	0	0	195
23	**General Plant**	PTD	894	400	485	51	434	338	96	0	0	9
24	**Electric Common**	PTD	1,505	674	817	86	730	569	161	0	0	15
25	**Total Book Deprec**		19,769	9,225	10,278	1,159	9,119	7,138	1,982	0	0	266
	Real Estate & Property Tax											
	Production											
26	Peaking Plant	D10C	767	311	454	43	411	318	92	0	0	2
27	Base Load	E8760	2,198	773	1,413	115	1,298	991	307	0	0	11
28	Total		2,965	1,084	1,867	158	1,709	1,310	399	0	0	13
	Transmission											
29	Gen Step Up Base	E8760	71	25	46	4	42	32	10	0	0	0
30	Gen Step Up Peak	D10C	250	101	148	14	134	104	30	0	0	1
31	Total Gen Step Up		321	126	194	18	176	136	40	0	0	1
32	Bulk Transmission	D10T	1,125	456	665	63	602	468	134	0	0	4
33	Distrib Function	D60Sub	1	0	1	0	1	0	0	0	0	0
34	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
35	Total		1,447	583	859	81	778	604	174	0	0	5
	Distribution											
36	Generat Step Up	STRATH	0	0	0	0	0	0	0	0	0	0
37	Bulk Transmission	D10T	25	10	15	1	13	10	3	0	0	0
38	Distrib Function	D60Sub	254	103	149	14	135	104	31	0	0	2
39	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
40	Total Substations		279	114	163	15	148	115	34	0	0	2
41	Overhead Lines	POL	290	174	104	19	85	70	14	0	0	12
42	Underground	PUL	435	329	104	34	70	66	4	0	0	2
43	Line Transformers	P68	297	199	97	21	76	74	2	0	0	1
44	Services	P69	119	107	12	5	7	7	0	0	0	0
45	Meters	C12WM	117	81	35	16	19	18	2	0	0	1
46	Street Lighting	P73	20	0	0	0	0	0	0	0	0	20
47	Total		1,557	1,003	515	110	406	349	57	0	0	39
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 Rl Est & Pr Tax**		5,969	2,670	3,242	349	2,893	2,263	630	0	0	57
51	Gross Earnings Tax	R01; R02	0	0	0	0	0	0	0	0	0	0
52	Payroll Taxes	LABOR	1,670	723	927	100	826	641	186	0	0	20
53	**Tot Non-Inc Taxes**		7,639	3,394	4,168	449	3,719	2,904	816	0	0	77

Provision For Defer Inc Tax

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**SD**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10C	1,820	738	1,077	102	975	755	219	0	0	5
2	Nuclear Fuel	E8760	392	138	252	21	232	177	55	0	0	2
3	Base Load	E8760	7,369	2,593	4,738	386	4,352	3,324	1,029	0	0	38
4	Total		9,581	3,469	6,067	509	5,558	4,256	1,303	0	0	45
	Transmission											
5	Gen Step Up Base	E8760	158	56	102	8	93	71	22	0	0	1
6	Gen Step Up Peak	D10C	85	34	50	5	46	35	10	0	0	0
7	Total Gen Step Up		243	90	152	13	139	107	32	0	0	1
8	Bulk Transmission	D10T	2,922	1,184	1,727	164	1,563	1,215	348	0	0	11
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		3,165	1,274	1,879	177	1,702	1,322	381	0	0	12
	Distribution											
12	Generat Step Up	STRATH	1	0	1	0	1	0	0	0	0	0
13	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub	277	113	162	15	147	114	33	0	0	2
15	Direct Assign	Dir Assign	(1)	0	(1)	0	(1)	0	(1)	0	0	0
16	Total Substations		277	113	162	15	147	114	33	0	0	2
17	Overhead Lines	POL	722	433	258	47	211	175	36	0	0	31
18	Underground	PUL	890	673	213	70	143	134	9	0	0	4
19	Line Transformers	P68	(90)	(60)	(29)	(6)	(23)	(22)	(1)	0	0	(0)
20	Services	P69	(34)	(31)	(3)	(1)	(2)	(2)	0	0	0	0
21	Meters	C12WM	6	4	2	1	1	1	0	0	0	0
22	Street Lighting	P73	18	0	0	0	0	0	0	0	0	18
23	Total		1,789	1,132	602	125	477	400	77	0	0	55
24	**General Plant**	PTD	607	272	329	35	295	229	65	0	0	6
25	**Electric Common**	PTD	10	4	5	1	5	4	1	0	0	0
26	**Net Operating Loss (NOL) Carry For**	NEPIS	(8,940)	(4,170)	(4,696)	(525)	(4,171)	(3,264)	(907)	0	0	(74)
27	**Non - Plant Related**	LABOR	(187)	(81)	(104)	(11)	(93)	(72)	(21)	0	0	(2)
28	**Tot Prov For Defer**		6,025	1,901	4,083	309	3,773	2,875	899	0	0	41

Investment Tax Credit For Current Income

Inv Tax Credit; Total Oper Exp

			SD	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
	Production											
29	Peaking Plant	D10C	(18)	(7)	(11)	(1)	(10)	(7)	(2)	0	0	(0)
30	Base Load	E8760	(35)	(12)	(23)	(2)	(21)	(16)	(5)	0	0	(0)
31	Total		(53)	(20)	(33)	(3)	(30)	(23)	(7)	0	0	(0)
	Transmission											
32	Bulk Transmission	D10T	(30)	(12)	(18)	(2)	(16)	(12)	(4)	0	0	(0)
33	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
34	Total		(30)	(12)	(18)	(2)	(16)	(12)	(4)	0	0	(0)
	Distribution											
35	Overhead Lines	POL	0	0	0	0	0	0	0	0	0	0
36	Underground	PUL	0	0	0	0	0	0	0	0	0	0
37	Total		0	0	0	0	0	0	0	0	0	0
38	**General Plant**	PTD	0	0	0	0	0	0	0	0	0	0
39	**Electric Common**	PTD	0	0	0	0	0	0	0	0	0	0
40	**Net Inv Tax Credit**		(83)	(32)	(51)	(5)	(46)	(36)	(11)	0	0	(0)
41	**Total Operating Exp**		177,235	70,820	104,864	10,016	94,848	73,074	21,774	0	0	1,551
42A	**Pres Op Inc Before Inc Tax**		19,001	9,546	9,298	1,116	8,182	7,389	792	0	0	157
42B	**Prop Op Inc Before Inc Tax**		33,584	16,032	17,325	2,051	15,274	13,010	2,264	0	0	227

Tax Deprec; Inc Tax & Return

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**SD**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10C	8,477	3,440	5,016	475	4,540	3,519	1,021	0	0	22
2	Nuclear Fuel	E8760	7,093	2,495	4,561	372	4,189	3,199	990	0	0	37
3	Base Load	E8760	26,456	9,307	17,011	1,386	15,624	11,931	3,693	0	0	138
4	Total		42,026	15,242	26,587	2,233	24,353	18,649	5,704	0	0	197
	Transmission											
5	Gen Step Up Base	E8760	452	159	291	24	267	204	63	0	0	2
6	Gen Step Up Peak	D10C	243	99	144	14	130	101	29	0	0	1
7	Total Gen Step Up		695	258	434	37	397	305	92	0	0	3
8	Bulk Transmission	D10T	9,598	3,890	5,673	538	5,135	3,991	1,144	0	0	35
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		10,294	4,147	6,108	575	5,533	4,296	1,238	0	0	38
	Distribution											
12	Generat Step Up	STRATH	8	3	5	0	5	4	1	0	0	0
13	Bulk Transmission	D10T	3	1	2	0	2	1	0	0	0	0
14	Distrib Function	D60Sub	1,535	625	898	83	815	630	186	0	0	13
15	Direct Assign	Dir Assign	6	0	6	0	6	0	6	0	0	0
16	Total Substations		1,552	629	911	83	827	634	193	0	0	13
17	Overhead Lines	POL	3,191	1,913	1,142	208	934	776	158	0	0	136
18	Underground	PUL	4,270	3,229	1,021	334	687	643	44	0	0	20
19	Line Transformers	P68	282	189	92	20	72	70	2	0	0	1
20	Services	P69	657	590	67	28	40	40	0	0	0	0
21	Meters	C12WM	207	144	62	28	34	31	3	0	0	1
22	Street Lighting	P73	137	0	0	0	0	0	0	0	0	137
23	Total		10,296	6,693	3,295	701	2,595	2,194	401	0	0	308
24	**General Plant**	PTD	2,619	1,173	1,421	150	1,271	990	281	0	0	25
25	**Electric Common**	PTD	1,463	655	794	84	710	553	157	0	0	14
26	Net Operating Loss (NOL) Carry Forwa	NEPIS	(20,416)	(9,522)	(10,725)	(1,200)	(9,525)	(7,453)	(2,072)	0	0	(169)
27	**Total Tax Deprec**		46,282	18,388	27,481	2,544	24,937	19,228	5,709	0	0	414
28	**Interest Expense**		9,734	4,514	5,136	572	4,564	3,569	995	0	0	84
29	Other Tax Timing Differ		(456)	(185)	(270)	(26)	(244)	(190)	(54)	0	0	(2)
30	Total Tax Deductions		55,560	22,717	32,347	3,090	29,257	22,608	6,649	0	0	496
	Inc Tax Additions											
31	Book Depreciation		19,769	9,225	10,278	1,159	9,119	7,138	1,982	0	0	266
32	Deferred Inc Tax & ITC		5,942	1,869	4,032	305	3,727	2,839	888	0	0	41
33	Nuclear Fuel Book Burn	E8760	6,607	2,324	4,248	346	3,902	2,980	922	0	0	34
34	Nuclear Fuel Disposal	E8760	0	0	0	0	0	0	0	0	0	0
35	Meals & Entertainment	LABOR	(43)	(19)	(24)	(3)	(21)	(16)	(5)	0	0	(1)
36	Avoided Tax Interest	RTBASE	1,308	607	690	77	613	480	134	0	0	11
37	Total Tax Additions		36,806	15,449	20,973	2,069	18,904	14,638	4,266	0	0	384
38	**Total Inc Tax Adjustments**		(18,754)	(7,268)	(11,374)	(1,021)	(10,353)	(7,970)	(2,383)	0	0	(112)
39A	**Pres Taxable Net Income**		247	2,278	(2,076)	95	(2,172)	(581)	(1,591)	0	0	45
39B	**Prop Taxable Net Income**		14,830	8,765	5,951	1,030	4,921	5,040	(119)	0	0	114
40A	Pres Fed & State Inc Tax		86	797	(727)	33	(760)	(203)	(557)	0	0	16
40B	Prop Fed & State Inc Tax		5,190	3,068	2,083	360	1,722	1,764	(42)	0	0	40
41A	Pres Preliminary Return	(total); BASE	18,914	8,748	10,025	1,083	8,942	7,593	1,349	0	0	142
41B	Prop Preliminary Return	(total); BASE	28,393	12,965	15,242	1,690	13,552	11,246	2,306	0	0	187
42	Total AFUDC		0	0	0	0	0	0	0	0	0	0
43A	**Present Total Return**		18,914	8,748	10,025	1,083	8,942	7,593	1,349	0	0	142
43B	**Proposed Total Return**		28,393	12,965	15,242	1,690	13,552	11,246	2,306	0	0	187
44A	**Pres % Return on Rate Base**		5.85%	5.83%	5.87%	5.70%	5.90%	6.40%	4.08%	0.00%	0.00%	5.06%
44B	**Prop % Return on Rate Base**		8.78%	8.65%	8.93%	8.90%	8.94%	9.48%	6.98%	0.00%	0.00%	6.68%
45A	**Present Common Return**		9,180	4,235	4,888	511	4,377	4,023	354	0	0	57
45B	**Proposed Common Return**		18,659	8,451	10,106	1,118	8,987	7,677	1,311	0	0	103
46A	**Pres % Ret on Common Rate Base**		5.41%	5.38%	5.46%	5.13%	5.50%	6.47%	2.04%	0.00%	0.00%	3.91%
46B	**Prop % Ret on Common Rate Base**		10.99%	10.74%	11.29%	11.22%	11.29%	12.34%	7.56%	0.00%	0.00%	6.99%

Allow For Funds Used During Constr

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**SD**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10C	0	0	0	0	0	0	0	0	0	0
2	Nuclear Fuel	E8760	0	0	0	0	0	0	0	0	0	0
3	Base Load	E8760	0	0	0	0	0	0	0	0	0	0
4	Total		0	0	0	0	0	0	0	0	0	0
	Transmission											
5	Gen Step Up Base	E8760	0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10C	0	0	0	0	0	0	0	0	0	0
7	Total Gen Step Up		0	0	0	0	0	0	0	0	0	0
8	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
11	Total		0	0	0	0	0	0	0	0	0	0
	Distribution											
12	Generat Step Up	STRATH	0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
16	Total Substations		0	0	0	0	0	0	0	0	0	0
17	Overhead Lines	POL	0	0	0	0	0	0	0	0	0	0
18	Underground	PUL	0	0	0	0	0	0	0	0	0	0
19	Line Transformers	P68	0	0	0	0	0	0	0	0	0	0
20	Services	P69	0	0	0	0	0	0	0	0	0	0
21	Meters	C12WM	0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73	0	0	0	0	0	0	0	0	0	0
23	Total		0	0	0	0	0	0	0	0	0	0
24	**General Plant**	PTD	0	0	0	0	0	0	0	0	0	0
25	**Electric Common**	PTD	0	0	0	0	0	0	0	0	0	0
26	**Total AFUDC**		0	0	0	0	0	0	0	0	0	0

Labor Allocator

			SD	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
	Production											
27	Other Prod - Cap	OXOPD	4,820	1,956	2,852	270	2,582	2,001	581	0	0	12
28	Other Prod - Ene	E8760	8,981	3,160	5,775	471	5,304	4,050	1,254	0	0	47
29	Total		13,801	5,115	8,627	741	7,886	6,051	1,834	0	0	59
	Transmission											
30	Stepup Subtrans	P5161A	34	13	21	2	19	15	5	0	0	0
31	Bulk Power Subs	D10T	916	371	541	51	490	381	109	0	0	3
32	Total		950	384	563	53	510	396	114	0	0	4
	Distribution											
33	Superv & Eng	ZDTS	501	303	174	36	138	115	23	0	0	24
34	Load Dispatch	D10T	231	94	137	13	124	96	28	0	0	1
35	Substation	P61	232	93	137	12	124	94	30	0	0	2
36	Overhead Lines	POL	725	435	259	47	212	176	36	0	0	31
37	Underground Lines	PUL	804	608	192	63	129	121	8	0	0	4
38	Line Transformer	P68	1	1	0	0	0	0	0	0	0	0
39	Meter	C12WM	218	151	65	29	36	33	4	0	0	1
40	Cust Installation	ZDTS	128	77	45	9	35	29	6	0	0	6
41	Street Lighting	P73	63	0	0	0	0	0	0	0	0	63
42	Miscellaneous	OXDTS	328	192	114	22	92	76	16	0	0	22
43	Total		3,231	1,954	1,124	232	891	741	151	0	0	154
44	**Cust Accounting**	C11WA	854	682	166	104	62	60	1	0	0	7
45	**Sales Expense**	C11P10	2	1	1	0	1	0	0	0	0	0
46	**Admin & General**	LABOR	7,888	3,417	4,377	474	3,903	3,027	877	0	0	94
47	**Service & Inform**	C11P10	144	88	54	10	44	34	10	0	0	2
48	**Labor**		26,870	11,641	14,910	1,614	13,296	10,310	2,987	0	0	319

Backwards Revenue Calc

		1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	(1A) Modified Pres Rev	**SD**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Present Preliminary Return (Before AFUDC)	18,914	8,748	10,025	1,083	8,942	7,593	1,349	0	0	142
2	1/(1-T) Rev Reqt (= 1.5385)	29,099	13,459	15,422	1,666	13,756	11,681	2,075	0	0	218
3	Total Inc Tax Adjustments	(18,754)	(7,268)	(11,374)	(1,021)	(10,353)	(7,970)	(2,383)	0	0	(112)
4	T/(1-T) Rev Reqt (= 0.5385)	(10,098)	(3,913)	(6,125)	(550)	(5,575)	(4,292)	(1,283)	0	0	(60)
5	Tot Op Exp W/o Regul Exp	176,865	70,665	104,653	9,995	94,658	72,924	21,733	0	0	1,547
6	- Other Retail Rev W/o Gr Earn, Etc	0	0	0	0	0	0	0	0	0	0
7	- Other Op Rev W/o Late Pay, Etc.	39,017	14,398	24,418	2,089	22,329	17,120	5,209	0	0	200
8	Modified Pres Net Oper Exp	137,848	56,266	80,235	7,906	72,329	55,804	16,525	0	0	1,347
9	**Mod Pres Rev (R02) (component alloc)**	156,849	65,812	89,532	9,022	80,510	63,193	17,317	0	0	1,504
	(1B) Present Revenue										
10	Tot Oper Exp (w/ Regul Exp)	177,235	70,820	104,864	10,016	94,848	73,074	21,774	0	0	1,551
11	- Other Retail Rev (w/ Gr Earn, Etc)	0	0	0	0	0	0	0	0	0	0
12	- Other Oper Rev (w/ Late Pay, Etc)	39,017	14,398	24,418	2,089	22,329	17,120	5,209	0	0	200
13	Net Oper Exp Rev Reqt	138,218	56,422	80,446	7,927	72,519	55,953	16,566	0	0	1,351
14	**Tot Pres Rate Rev Reqt (R01)**	157,219	65,967	89,744	9,043	80,700	63,343	17,358	0	0	1,508
		0	0	0	0	0	0	0	0	0	0
	(2) Proposed Return										
15	Total Operating Exp	177,235	70,820	104,864	10,016	94,848	73,074	21,774	0	0	1,551
16	- Other Retail Rev (w/ Gr Earn, Etc)	0	0	0	0	0	0	0	0	0	0
17	- Prop Other Operating Rev	39,065	14,418	24,446	2,092	22,354	17,140	5,214	0	0	201
18	Prop Net Oper Exp Rev Reqt	138,170	56,402	80,418	7,924	72,494	55,934	16,560	0	0	1,350
19	Prop Preliminary Return	28,393	12,965	15,242	1,690	13,552	11,246	2,306	0	0	187
20	1/(1-T) Rev Reqt (= 1.5385)	43,682	19,946	23,449	2,600	20,849	17,301	3,547	0	0	287
21	T/(1-T) Rev Reqt (= 0.5385)	(10,098)	(3,913)	(6,125)	(550)	(5,575)	(4,292)	(1,283)	0	0	(60)
22	**Total Proposed Rate Rev Reqt**	171,754	72,434	97,743	9,975	87,768	68,944	18,825	0	0	1,577
	(3) Equal Return Rev										
23	T/(1-T) Rev Reqt (= 0.5385)	(10,098)	(3,913)	(6,125)	(550)	(5,575)	(4,292)	(1,283)	0	0	(60)
24	Equal Net Oper Exp Rev Reqt	138,170	56,402	80,418	7,924	72,494	55,934	16,560	0	0	1,350
25	Equal Rate of Ret (8.78%) x Rate Base	28,393	13,166	14,982	1,668	13,314	10,411	2,902	0	0	246
26	- AFUDC	0	0	0	0	0	0	0	0	0	0
27	Net Return	28,393	13,166	14,982	1,668	13,314	10,411	2,902	0	0	246
28	1/(1-T) Rev Reqt (= 1.5385)	43,682	20,256	23,049	2,566	20,483	16,018	4,465	0	0	378
29	**Net Equal-Ret Rate Rev-Reqt (R99)**	171,754	72,744	97,343	9,941	87,402	67,660	19,742	0	0	1,667
30	Tot Oper Rev - Equal	210,819	87,162	121,788	12,033	109,756	84,800	24,956	0	0	1,868
31	- Total Operating Exp	177,235	70,820	104,864	10,016	94,848	73,074	21,774	0	0	1,551
32	Equal Op Inc Before Inc Tax	33,584	16,342	16,924	2,016	14,908	11,726	3,182	0	0	317
33	Equal Taxable Net Income	14,830	9,075	5,550	995	4,555	3,756	799	0	0	205
34	Equal Fed & State Inc Tax	5,190	3,176	1,943	348	1,594	1,315	280	0	0	72
35	Proposed Common Return	18,659	8,652	9,846	1,096	8,749	6,842	1,907	0	0	161
36	Equal Return on Common	10.99%	10.99%	10.99%	10.99%	10.99%	10.99%	10.99%	0.00%	0.00%	10.99%

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
INTERNAL ALLOCATORS		Intern:	**SD**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**Rate Base: Col %'s**	**BASE-COL**	**1000.000%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**
			100.000%									
2	50% Cus, 50% Prod Plt	C11P10	100.000%	61.024%	37.615%	7.002%	30.613%	23.859%	6.754%	0.000%	0.000%	1.361%
3	Peaking Plant Capacity	D10C	100.000%	40.575%	59.169%	5.608%	53.561%	41.517%	12.044%	0.000%	0.000%	0.256%
4	56% Dmd; 44% Energy: Sales & ED	D56E44	100.000%	38.190%	61.437%	5.445%	55.991%	43.100%	12.891%	0.000%	0.000%	0.374%
5	42% Dmd; 58% Energy: CIP	D42E58	100.000%	40.510%	59.231%	5.604%	53.628%	41.560%	12.068%	0.000%	0.000%	0.259%
6	Labor w/o (or w/) A&G	LABOR	100.000%	43.322%	55.491%	6.006%	49.484%	38.369%	11.115%	0.000%	0.000%	1.187%
7	Net Plant In Service	NEPIS	100.000%	46.642%	52.531%	5.876%	46.654%	36.508%	10.147%	0.000%	0.000%	0.827%
8	Dis O&M w/o Sup & Misc	OXDTS	100.000%	58.403%	34.791%	6.747%	28.043%	23.164%	4.879%	0.000%	0.000%	6.807%
9	Other Prod Capac O&M	OXOPD	100.000%	40.575%	59.169%	5.608%	53.561%	41.517%	12.044%	0.000%	0.000%	0.256%
10	O&M w/o Reg Ex & OXTS-Alloc'd A&G	OXTS	100.000%	39.144%	60.046%	5.632%	54.414%	41.838%	12.576%	0.000%	0.000%	0.810%
11	Production Plant	P10	100.000%	36.649%	62.901%	5.340%	57.561%	44.123%	13.438%	0.000%	0.000%	0.450%
12	Production Plant Wo Nuclear	P10WoN	100.000%	37.064%	62.506%	5.369%	57.138%	43.848%	13.290%	0.000%	0.000%	0.429%
13	Total P51 & P61A	P5161A	100.000%	37.006%	62.562%	5.365%	57.198%	43.887%	13.311%	0.000%	0.000%	0.432%
14	Distribution Plant	P60	100.000%	66.421%	31.067%	6.759%	24.308%	20.682%	3.626%	0.000%	0.000%	2.513%
15	Distr Substn Plant	P61	100.000%	40.268%	58.926%	5.333%	53.593%	40.647%	12.946%	0.000%	0.000%	0.806%
16	Line Transformer Plant	P68	100.000%	66.879%	32.639%	7.003%	25.636%	24.928%	0.708%	0.000%	0.000%	0.482%
17	Services Plant	P69	100.000%	89.754%	10.246%	4.219%	6.027%	6.027%	0.000%	0.000%	0.000%	0.000%
18	Dist Plt Overhead Lines	POL	100.000%	59.962%	35.788%	6.520%	29.268%	24.304%	4.965%	0.000%	0.000%	4.250%
19	Real Est & Property Tax	PT0	100.000%	44.735%	54.306%	5.839%	48.467%	37.912%	10.555%	0.000%	0.000%	0.958%
20	Produc, Trans & Distrib	PTD	100.000%	44.776%	54.258%	5.738%	48.520%	37.791%	10.729%	0.000%	0.000%	0.966%
21	Dist Plt Undground Lines	PUL	100.000%	75.612%	23.914%	7.823%	16.091%	15.058%	1.033%	0.000%	0.000%	0.474%
22	Rev w/o Reg, etc: Col %	R02-COL	1000.000%	N/A	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
			100.000%	46.25%	53.00%	5.73%	47.27%	40.14%	7.13%	0.00%	0.00%	0.75%
			100.000%	45.66%	53.68%	5.95%	47.73%	39.61%	8.12%	0.00%	0.00%	0.66%
23	Rate Base (Non-Column)	RTBASE	100.000%	46.370%	52.765%	5.874%	46.890%	36.668%	10.222%	0.000%	0.000%	0.865%
24	Stratified Hydro Baseload	STRATH	100.000%	35.994%	63.524%	5.296%	58.228%	44.558%	13.670%	0.000%	0.000%	0.482%
25	Transmission & Distrib	TD	100.000%	57.311%	40.927%	6.351%	34.576%	28.025%	6.551%	0.000%	0.000%	1.762%
26	Labor Dis w/o Sup & Eng	ZDTS	100.000%	60.467%	34.773%	7.183%	27.590%	22.925%	4.665%	0.000%	0.000%	4.759%

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
INTERNAL DATA			**SD**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
27	Labor w/o A&G	LABOR(S)	18,982	8,223	10,533	1,140	9,393	7,283	2,110	0	0	225
28	Dis O&M w/o Sup, Cust Install & Misc	OXDTS	4,573	2,671	1,591	309	1,282	1,059	223	0	0	311
29	O&M w/o Reg Ex & OXTS-Alloc'd A&G	OXTS	141,299	55,310	84,844	7,958	76,886	59,117	17,769	0	0	1,145
30	Total P51 & P61A	P5161A	3,632	1,344	2,272	195	2,077	1,594	483	0	0	16
31	Produc, Trans & Distrib	PTD	706,194	316,209	383,163	40,521	342,642	266,877	75,764	0	0	6,822
32	Transmission & Distrib	TD	277,787	159,202	113,689	17,643	96,047	77,850	18,197	0	0	4,896
33	Labor Dis w/o Sup & Eng, Cust Install	ZDTS	2,602	1,573	905	187	718	597	121	0	0	124

Northern States Power Company, a Minnesota Corporatior
Electric Utility - State of South Dakota
Test Year Ending December 31, 201C
Class Cost of Service Study Detail

Docket No. EL11-______
Exhibit No. ______(MAP-1)
Schedule 4

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
EXTERNAL ALLOCATORS		Extern:	**SD**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Customers - Ave Monthly	C11	100.00%	85.40%	12.33%	8.66%	3.67%	3.59%	0.07%	0.00%	0.00%	2.27%
2	Cust Acctg Wtg Factor	C11WA	100.00%	79.81%	19.40%	12.14%	7.25%	7.08%	0.17%	0.00%	0.00%	0.79%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	69.47%	30.00%	13.41%	16.59%	14.98%	1.61%	0.00%	0.00%	0.53%
4	Sec & Pri Customers	C61PS	100.00%	86.97%	12.57%	8.83%	3.74%	3.67%	0.07%	0.00%	0.00%	0.45%
5	C62Sec, w/o Ltg & C/I Underground	C62NL	100.00%	93.17%	6.83%	4.82%	2.01%	2.01%	0.00%	0.00%	0.00%	0.00%
6	Secondary Customers	C62Sec	100.00%	87.04%	12.51%	8.84%	3.67%	3.67%	0.00%	0.00%	0.00%	0.45%
7	Summer Peak Resp KW	D10S	100.00%	39.66%	60.34%	5.66%	54.68%	42.08%	12.60%	0.00%	0.00%	0.00%
8	Transmission Demand %	D10T	100.00%	40.53%	59.11%	5.60%	53.50%	41.58%	11.92%	0.00%	0.00%	0.37%
9	Winter Peak Resp KW	D10W	100.00%	42.62%	56.56%	5.48%	51.07%	40.26%	10.81%	0.00%	0.00%	0.83%
11	Sec, Pri & TT, Class Coin kW @ Subst	D60Sub	100.00%	40.70%	58.49%	5.38%	53.10%	41.01%	12.09%	0.00%	0.00%	0.82%
12	Sec & Pri, Cl Coin kW (no Min Sys; adj	D61PS	100.00%	37.12%	62.27%	4.80%	57.47%	44.26%	13.21%	0.00%	0.00%	0.61%
13	D62Sec, w/o Ltg & C/I Underground	D62NLL	100.00%	80.67%	19.33%	2.61%	16.72%	16.72%	0.00%	0.00%	0.00%	0.00%
14	Sec, Class Coin kW (w/o Min Sys kW)	D62SecL	100.00%	50.98%	48.53%	5.50%	43.02%	43.02%	0.00%	0.00%	0.00%	0.50%
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%	35.18%	64.30%	5.24%	59.06%	45.10%	13.96%	0.0000%	0.0000%	0.52%
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%	41.96%	57.08%	5.75%	51.33%	40.29%	11.04%	0.00%	0.00%	0.96%

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
APPLIED EXTERNAL DATA (BIG or LITTLE)			**SD**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Customers - B Basis	C10	82,975	72,167	10,432	7,326	3,106	3,046	60	0	0	376
2	Cust - Ave Monthly (C10-Area Lt)	C11	84,731	72,360	10,446	7,340	3,106	3,046	60	0	0	1,925
3	Mo Cus Wtd By Cus Acct	C11WA	90,543	72,263	17,561	10,996	6,565	6,414	152	0	0	719
4	Cust Acctg Wtg Factor	C11WAF	7.12	1.00	6.13	1.50	4.63	2.11	2.52	0.00	0.00	N/A
5	Cust-Ave Mo (C11 w/ Dir Assign St Ltg	C12	83,076	72,360	10,446	7,340	3,106	3,046	60	0	0	270
6	Mo Cus Wtd By Mtr Invest	C12WM	9,629,611	6,689,732	2,888,506	1,291,185	1,597,321	1,442,479	154,841	0	0	51,373
7	Meter Invest / Cust Factor	C12WMF	3,509	92	3,227	176	3,051	474	2,577	0	0	190
8	Sec & Pri Customers	C61PS	82,975	72,167	10,432	7,326	3,106	3,046	60	0	0	376
9	C62Sec, w/o Ltg & C/I Underground	C62NL	77,456	72,167	5,289	3,736	1,553	1,553	0	0	0	0
10	Secondary Customers	C62Sec	82,914	72,167	10,372	7,326	3,046	3,046	0	0	0	376
11	Summer Peak Resp KW	D10S	462,359	183,371	278,989	26,186	252,803	194,564	58,238	0	0	0
12	Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	4,052,786	5,910,535	560,398	5,350,137	4,158,030	1,192,108	0	0	36,679
13	Winter Peak Resp KW	D10W	306,385	130,569	173,283	16,804	156,480	123,346	33,134	0	0	2,532
15	Sec, Pri & TT, Class Coin kW @ Subst	D60Sub	513,119	208,822	300,099	27,628	272,470	210,444	62,026	0	0	4,199
16	Sec & Pri, Class Coin kW (w/o Min Sys	D61PS	469,148	174,138	292,151	22,522	269,630	207,662	61,968	0	0	2,859
17	D62Sec, w/o Ltg & C/I Underground	D62NLL	726,484	586,057	140,427	18,968	121,459	121,459	0	0	0	0
18	Sec, Class Coin kW (w/o Min Sys kW)	D62SecL	10,000,000	5,097,815	4,852,641	550,226	4,302,415	4,302,415	0	0	0	49,543
19	Annual Billing kW	D99	3,150.684	0	3,151	0	3,151	2,545	606	0	0	0
20	Summer Billing kW	D99S	1,201.805	0	1,202	0	1,202	965	237	0	0	0
21	Winter Billing kW	D99W	1,948.879	0	1,949	0	1,949	1,580	369	0	0	0
22	Non-Coinc Pk Second	DN-Sec	990,136	586,057	401,220	54,194	347,026	347,026	0	0	0	2,859
23	kWh Sales @ Meter	E99	1,985,982	685,877	1,286,603	100,682	1,185,921	892,226	293,695	0	0	13,502

ALLOCATOR CONSTANTS

1	% D10 O&M Econ Develop	Econ Dev Dmd			55.78%
2	% D10 O&M CIP/DSM	CIP Dmd			98.79%
1	On Peak Energy Wtg Factor For E20	ONPKWF			1.585
2	APL Inv In OH Lines: Dir Assignable	**POLAPL**			85
3	Summer Factor	SFAC			0.6904
4	Overhead Lines St Ltg Comp Owned	**QQOSL1**			2.440%
5	Overhead Lines Area Lighting	**QQOSL2**			1.133%
6	Overhead Lines Primary - Customer	**QQ64C**			27.445%
7	Overhead Lines Primary - Demand	**QQ64D**			37.503%
8	Overhead Lines Secondary - Customer	**QQ65C**			17.288%
9	Overhead Lines Secondary - Demand	**QQ65D**			14.190%
10	Overhead Total				100.000%
11	Underground Primary - Customer	**QQ66C**			46.190%
12	Underground Primary - Demand	**QQ66D**			7.570%
13	Underground Secondary - Customer	**QQ67C**			25.115%
14	Underground Secondary - Demand	**QQ67D**			21.125%
15	Underground Total				100.000%
16	Line Trans Secondary - Customer	**QQ68C**			46.160%
17	Line Trans Secondary - Demand	**QQ68D**			48.480%
18	Line Trans Primary - Demand	**QQ68P**			5.360%
19	Line Trans Total				100.000%
20	Services - Customer	**QQ69C**			72.670%
21	Services - Demand	**QQ69D**			27.330%
22	Services Total				100.000%
23	Stratified Nuclear Baseload (JCOSS on	**STRNBL**			0.8041
24	Stratified Fossil Baseload (JCOSS only	**STRFBL**			0.6275
25	Stratified Hydro Baseload	**STRHBL**			0.8492

CALCULATED CONSTANTS

26	Net Overhead Lines Investment	**QPOLS**			46,328
27	Ovhd Lines St Ltg Co - Assignable	**QQSL1**			1,130
28	Ovhd Lines Area Ltg - Assignable	**QQSL2**			525
29	Ovhd St Lt + Area Lt + Dir Assign	**QQSLTOT**			1,740
30	**Production Plant: % Peaking Vs Baseload**				0.349244
31	**Peaking Factor For Purchased Power**				0.7215
32	State Tax Rate		0.00%		
33	State Tax Credit		0		
34	Federal Tax Rate		35.00%		
35	Federal Tax Credit		0		
	Capital Structure		**Cost**	**Ratio**	**Wtd Cost**
36	Long Term Debt		6.33%	47.52%	3.01%
37	Short Term Debt		0.00%	0.00%	0.00%
38	Preferred Stock		0.00%	0.00%	0.00%
39	Equity		11.00%	52.48%	5.7700000%

CALCULATED CONSTANTS

40	Proposed Overal Return			8.78%
41	Interest Exp Factor	DETFACT		3.0100%
42	Debt Ratio	DETRATIO		47.52000%
43	Embedded Cost of Debt	DETCOST		6.3300%
44	360 Preferred Factor	P360FACT		0.0000%
45	Preferred Factor	PFDFACT		0.0000%
46	Rev Increase Percent	INCRPCT		9.2451%
47	1 / (1 - Tax Rate) Factor	ONEOVER	Present	153.8462%
48	Tax Rate / (1 - Tax Rate) Factor	TAXOVER	Present	53.8462%
49	1 / (1 - Tax Rate) Factor	ONEOVER	Proposed	153.8462%
50	Tax Rate / (1 - Tax Rate) Factor	TAXOVER	Proposed	53.8462%

VOLTAGE DISCOUNT ANALYSIS - DEMAND ($/kW)

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 34,33,32)	$1,752.195	$2,208.112	$1,933.784
2. Billing KW (Workpaper attached)			
Secondary Voltage kW	2,544,887	2,544,887	2,544,887
Loss Factor	1.0000	1.0220	1.0639
Secondary With Losses	**2,544,887**	**2,600,811**	**2,707,386**
Primary Voltage kW		605,796	605,796
Loss Factor		1.0000	1.0410
Primary With Losses		**605,796**	**630,620**
Transmission Transformed Voltage kW			**0**
Total kW (Metered Sales + Losses)	**2,544,887**	**3,206,608**	**3,338,006**
3. Rev Reqt / kW (Line 1 / Line 2)	$0.6885	$0.6886	$0.5793
4. Cumulative Rev Reqt/ kW	**$0.69**	**$1.38**	**$1.96**
5. Present Individual Discounts	$0.80	$0.70	$0.50
6. Cumulative Present Discount	**$0.80**	**$1.50**	**$2.00**
7. Midpoint-Pres and Rev Reqt (Lines 4+ 6 /2)	$0.74	$1.44	$1.98
8. Cumulative Proposed Discount (Rounded to nearest $0.05)	**$0.70**	**$1.40**	**$2.00**

Demand Component	Loss Factors
Secondary Lines	0.9170
Primary Lines	0.9371
Primary Substations	0.9755
Transmission	0.9788

Northern States Power Company, a Minnesota Corporation **Docket No. EL11-_____**
Electric Utility - South Dakota **Exhibit_____(MAP-1)**
Test Year Ending December 31, 2010 **Schedule 5**

VOLTAGE DISCOUNT ANALYSIS - ENERGY (¢/kWh)

Voltage	[1] E8760 Losses	[2] Percent Difference	[3] Energy Charge	[4] Cost-Based Discount	[5] Proposed Discount	[6] Present Discount	
Secondary	7.28%	0.00%	**5.285**	0.0000	**0.000**	0.000	¢ per kWh
Primary	5.33%	1.94%	5.182	0.1028	**0.100**	0.080	¢ per kWh
T Transformed	2.58%	4.69%	5.037	0.2480	**0.250**	0.140	¢ per kWh
Transmission	2.25%	5.03%	5.019	0.2656	**0.270**	0.200	¢ per kWh

TARIFF	Current Tariff Charge	2010 Costs	Proposed Tariff Charge
Service Reconnection Charge	$ 22.50	$ 58.44	**$ 50.00**

Service Charges Section 6.1.2	**Costs**
Description	**Reconnects (1)**
Customer Call Center (CCC)	
Call Center reps to process service application	$ -
Administrative charge to process service application	$ -
Call Center reps to lock	$ 1.54
Administrative charge to lock	$ 3.68
Call Center reps to unlock	$ 1.54
Administrative charge to unlock	$ 3.68
Call Center reps to relock	$ -
Administrative charge to relock	$ -
Credit Field Calls (lock)	
Vehicle charge to lock	$ 2.85
Labor needed to Lock Meter (Credit)	$ 19.17
Credit Field Calls (unlock)	
Vehicle charge to unlock	$ 2.85
Labor needed to Unlock Meter (Credit)	$ 19.17
Vehicle charge to verify/relock	$ -
Labor needed to verify/relock Meter (Credit)	$ -
Travel to UNLOCK or RELOCK	$ 3.15
Producing bill	$ 0.10
Mailing bill	$ 0.35
New customer packet cost	**$ -**
Call Center IT costs per call	$ 0.36
Cost Per Transaction	**$ 58.44**

NOTES:

Note 1: The cost for reconnecting service which has been disconnected for non-payment.

Northern States Power Co., a Minnesota corporation
Electric Utility - South Dakota
Test Year Ending December 31, 2010
Dedicated Switching Cost Analysis

Docket No. EL11-________
Exhibit_____(MAP-1)
Schedule 6

	Normal 2010 $ $/hour	Overtime Mon-Sat x 1.5% 2010 $/hour	Overtime Sun-Fed Holidays x 2.0% 2010 $/hour
Dispatching labor cost	$ 3.55	$ 5.32	$ 10.64
Troubleman labor	$ 183.07	$ 274.61	$ 366.14
Administrative @ 5% of Troubleman labor	$ 9.15	$ 13.73	$ 18.31
Sub total labor	**$ 195.77**	**$ 293.66**	**$ 395.09**
Trouble truck	$ 42.35	$ 42.35	$ 42.35
Total Trouble Costs	**$ 238.12**	**$ 336.01**	**$ 437.44**
Call Center labor cost per call	$ 1.54	$ 1.54	$ 1.54
Call Center IT costs per call	$ 0.36	$ 0.36	$ 0.36
Producing bill	$ 0.10	$ 0.10	$ 0.10
Postage for bill	$ 0.35	$ 0.35	$ 0.35
Total Billing Costs	**$ 2.35**	**$ 2.35**	**$ 2.35**
TOTAL COSTS	**$ 240.47**	**$ 338.36**	**$ 439.79**

TARIFF	Charge per hour		
Requested Appointment Date	**Tariff $**	**2010 $**	**Proposed 2011 $**
Monday through Saturday	$ 250.00	$ 338.36	**$ 300.00**
Sunday and federally observed holidays	$ 300.00	$ 439.79	**$ 400.00**

Labor	p/hour Loaded
Straight time/hour	**68.92%**
$ 42.01	$ 70.96
$ 39.41	$ 66.57
Troubleman Overtime @ 1.5%	
Hourly rate @ 1.5%	**$ 99.86**
Troubleman Overtime @ 2.0%	
Hourly rate @ 2.0%	$ 133.14

Time for Avg Dedicated Switch Call	
Task	Minutes
Dispatch tasks	
Scheduling	**3**
Troubleman tasks	
Drive to site	**40**
Drive from/to next site	**35**
Site work	**90**
Total	**165**

Trouble Truck Analysis	
Monthly lease	**$ 2,664.00**
Monthly hours	**173**
Hourly cost	$ 15.40

Northern States Power Co., a Minnesota corporation
Electric Utility - South Dakota
Test Year Ending December 31, 2010
Excess Footage Cost Analysis

Current Costs from Passport System

TARIFF	Passport costs	Overhead	Total Costs	Current Electric tariff per circuit foot	Proposed Tariff Charge per circuit foot
Services	$ 5.92	34.00%	$7.93	$6.85	**$7.90**
Excess single phase primary or secondary extension	$ 6.00	34.00%	$8.04	$7.50	**$8.00**
Excess three phase primary or secondary extension	$ 10.41	34.00%	$13.95	$9.50	**$13.90**

Equipment Specifications

Assumptions - based off 100 ft service
Single Phase secondary = 4/0 alum tri w/ installation
Single Phase primary = #2 alum 1/0 primary with installation
3 Phase primary or secondary = 1/0 alum 3/0 primary w/installation
Engineering and Supervision Overhead: average rate from January to Aug 2010 is 34%

2010 Updates to Charges

TARIFF								
Current Electric Charge			20010 Costs		Proposed Tariff Charge			
Service Extension	$ 400.00	per frost burner	$ 597.20	per frost burner	Thawing	$ 600.00	per frost burner	
	$ 3.00	plus per trench foot	$ 3.81	plus per trench foot	Service, Primary, or Secondary distribution extension	$ 3.80	per foot	

2010 Winter Construction Burner Costs

Before January 1st
Typically burn for 2 days
A burner requires 3 - 20 lbs propane tanks to run for 2 days (20lbs tank = 5 gallons)

process	Crew or Vehicle:	time to do	cost pr hr	cost	cost per gallon	gallons used	propane cost	Totals
Set burner	Two man crew	1	$75.00	$75.00				
Re-tank burner	Two man crew	0	$75.00	$0.00				
Remove burner	Two man crew	0.5	$75.00	$37.50				
Total Labor				$112.50				
Labor Loading @ 68.92%				$77.54				
Labor w/Loading				$190.04				$190.04
Vehicle & Equipment	truck and trailer	1.5	36	$54.00				$54.00
Propane Cost					2.18	15	$32.70	$32.70
Costs (before E&S)				$276.74				$276.74
E&S cost @ 34%				$94.09				$94.09
Total Cost								$370.82

After January 1st
Typically burn for 3 days

process	Crew or Vehicle:	time to do	cost pr hr	cost	cost per gallon	gallons used	propane cost	Totals
Set burner	Two man crew	1	$75.00	$75.00				
Re-tank burner	Two man crew	1	$75.00	$75.00				
Remove burner	Two man crew	0.5	$75.00	$37.50				
Total Labor				$187.50				
Labor Loading @ 68.92%				$129.23				
Labor w/Loading				$316.73				$316.73
Vehicle & Equipment	truck and trailer	2.5	36	$90.00				$90.00
Propane Cost					2.18	22.5	$49.05	$49.05
Costs (before E&S)				$455.78				$455.78
E&S cost @ 34%				$154.96				$154.96
Total Cost								$610.74

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

Before and after January Costs	Percentage	
$370.82	10%	$37.08
$610.74	90%	$549.66
		$586.75

Billing Labor	$10.00
Producing Bill	$0.10
Postage	$0.35
Total Cost of a Burner	**$597.20**

2010 Winter Construction Per foot Charge

Winter Construction billed for in Winter of 09/10.

2010 Winter Construction Per foot Charge

Winter Construction billed for in Winter of 09/10.

Average Cost per foot Winter 2009-10 Services =	$14.45	per foot
Average Cost per foot non Winter Months Services =	$10.64	per foot
Difference for Winter Construction	**$3.81**	**per foot**