Direct Testimony and Schedules
James P. Gilroy

Before the South Dakota Public Utilities Commission
State of South Dakota

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

Docket No. EL14-____
Exhibit___(JPG-1)

Class Cost of Service Study
and
Rate Design

June 23, 2014

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James P. Gilroy. 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 Northern States Power Company – Minnesota (NSPM) operating company of Xcel Energy, Inc. My title is Senior Pricing Analyst.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. My qualifications include more than 35 years of Company experience in the areas of Class Cost of Service Study (CCOSS) analysis and general utility pricing, for both gas and electric operations. A detailed statement of my qualifications and experience is provided as Exhibit___(JPG-1), Schedule 1.

Q. FOR WHOM ARE YOU TESTIFYING:

A. I am testifying on behalf of Xcel Energy.

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

A. The purpose of my testimony is to present the Company's proposed CCOSS and rate design, and sponsor Exhibit ___(NSP-1), Statement I and Exhibit ___(NSP-1), Statement O located in Volume 1 of our Application. I also sponsor the Company's rate schedules and tariffs. A summary of the proposed tariff changes proposed in this case is included in Exhibit ___ (JPG-1), Schedule 13.

II. CLASS COST OF SERVICE STUDY

A. Overview of Proposed Class Cost of Service Study

Q. HOW DOES THE COMPANY'S PROPOSED CCOSS COMPARE WITH THAT APPROVED BY THE SOUTH DAKOTA PUBLIC SERVICE COMMISSION IN THE COMPANY'S LAST GENERAL ELECTRIC RATE CASE, DOCKET NO. EL12-046?

A. The Company's proposed CCOSS reflects pro forma 2013 data. We have made three changes in our allocation methods since the last rate case. These allocation changes apply to the primary line cost allocation, fixed capacity and transmission costs and other production operations and maintenance (O&M) costs. I describe these changes further below.

Q. MR. GILROY, 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___(JPG-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. A summary of the CCOSS results at the class level is shown on Exhibit __ (JPG-1), Schedule 3.

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

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

B. Changes in Allocation Methods

Q. DOES THE COMPANY CONSIDER CHANGING ITS CLASS ALLOCATION METHOD IN EACH NEW RATE CASE?

A. Yes. In general, the Company would like to retain as much stability and consistency as possible in its CCOSS class allocators. However, the Company continually reviews the details of its system operations and plant investment, and will update the CCOSS as necessary to provide accurate determinations of class revenue responsibility.

Q. HAS THE COMPANY MADE ANY CHANGES IN THE CCOSS ALLOCATION METHODS IN THIS CASE?

A. Yes. The Company has made the following three specific allocation changes:

- Split the investment in overhead and underground primary distribution lines into separate categories for single-phase and multi-phase lines;
- Allocated the capacity portion of fixed production plant and transmission cost on each class load that is coincident with the Company's summer peak only;
- Changed allocation of Other Production Operating and Maintenance (O&M) expenses.

I will explain the reasons for making these changes below.

1. Phase-Specific Primary Line Cost Allocation

Q. WHY DID THE COMPANY SPLIT THE PLANT INVESTMENT FOR PRIMARY DISTRIBUTION LINES INTO SEPARATE CATEGORIES FOR SINGLE-PHASE LINES AND MULTI-PHASE LINES?

A. As noted above, the Company continually reviews the details of its system operations and investments, and this allocation change more precisely reflects how the distribution system is currently used to serve customers.

A significantly higher percentage of Residential customers are served from the single-phase primary distribution system than Commercial & Industrial (C&I) customers. Feeders originate at distribution substations in a 3-phase configuration and then typically split into three separate 1-phase lines that serve lower usage customers (although in less common cases the system may split into a 2-phase configuration). To quantify this situation, the Company's Geographic Information System (GIS) was queried to determine the percent of customers in each customer class that received service from the single-phase primary distribution system as opposed to the multi-phase primary distribution system (3-phase or the less common 2-phase system). As shown in Table 1 below, 79.8% of residential customers receive service off the 1-phase primary distribution system. This percent drops to 40.9% for non-demand commercial customers, 13.5% for C&I demand-billed customers served at secondary voltage and 17.4% for C&I demand-billed customers served at primary voltage.

Table 1

Percent of Customers Served by Single Phase Vs Multi-Phase

Primary Distribution Lines

Primary Distribution Line Serving the Customer Premise	Customer Class				
	Residential Customers	**Commercial Non Dmd Billed**	**C&I Secondary Customers**	**C&I Primary Customers**	**Lighting Customers**
1-Phase	79.8%	40.9%	13.5%	17.4%	50.4%
Multi-Phase	20.2%	59.1%	86.5%	82.6%	49.6%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

Accordingly, we developed a phase-specific primary line allocation method to more accurately allocate costs to the customers that benefit from those facilities.

Q. HOW DOES THE COMPANY SPLIT PRIMARY LINE, SECONDARY LINE, SECONDARY TRANSFORMER AND SERVICE DROP COSTS INTO DEMAND- AND CUSTOMER-RELATED COMPONENTS?

A. The Company separates these costs into demand- and customer-related components using the Minimum Distribution System (MDS) method, as explained here:

> 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.

Q. IS THE MDS METHOD ONE OF THE METHODS RECOGNIZED BY THE NARUC MANUAL FOR SEPARATING DISTRIBUTION PLANT COSTS INTO DEMAND- AND CUSTOMER-RELATED COMPONENTS?

A. Yes. The NARUC manual lists the MDS method (called the Minimum-Size Method in the Manual) as one of two methods used to determine the demand- and customer-related components of distribution facilities. See NARUC Manual, pages 90-92.

Q. PLEASE DESCRIBE THE STEPS THE COMPANY TOOK TO COMPLETE ITS MDS STUDY.

A. An MDS study requires the following analysis steps:

Step 1: The first step in conducting an MDS study is to determine the minimum size pole, conductor, transformer and service that are installed on the distribution system. The minimum sized equipment is selected in consultation with staff in the distribution engineering area using its field experience and its evaluation of the smallest practical sized equipment.

Step 2: Determine the cost per unit of the minimum sized plant (e.g. cost per pole, cost per conductor foot and cost per transformer).

Step 3: The cost per unit of the minimum sized plant is multiplied by the total inventory of each plant type (e.g. total number of poles, total conductor feet, total number of transformers).

Step 4: The total cost of the minimum sized plant is divided by the total cost of the actual sized distribution plant in the field. This ratio is deemed to be the Customer-related portion of the distribution plant investment, with the balance being the Capacity-related portion.

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

A. Yes. After the cost of primary distribution lines was split into Capacity versus Customer components based on the results of the Company's MDS study, the resulting costs were split further into 1-phase versus multi-phase components based on the above table. Finally, the Capacity and Customer primary distribution line cost allocators (labeled D61PS and C61PS, respectively) that are used to allocate the cost of multi-phase primary distribution costs were reduced to reflect the percent of customers in each class that receive service from single-phase primary distribution lines. The new allocators are labeled D61PS1Ph and C61PS1Ph. More detail on the development of these allocators is explained in page 2 of Exhibit___(JPG-1), Schedule 2, External Allocators. The most accurate class allocation of costs on the 1-phase portion of the primary voltage distribution system should be built around the 1-Phase row of Table 1, as more specifically reflected in the C61PS1Ph and D61PS1Ph allocators.

However, because electricity has to first flow through the multi-phase portion of the distribution system in order to reach the 1-phase portion of the system, the multi-phase portion of the primary voltage distribution system should not be allocated based on the Multi-Phase line in Table 1. All customers either directly use multi-phase wires by being located on them, or they indirectly use multi-phase wires by being located further downstream. Accordingly, C61PS and D61PS are still the appropriate allocators for the multi-phase portion of the primary voltage distribution system.

2. Allocation of Fixed Capacity and Transmission Costs

Q. PLEASE DESCRIBE THE COMPANY'S METHOD FOR ALLOCATING FIXED CAPACITY AND TRANSMISSION COSTS USED IN PRIOR RATE CASES.

A. Previously, to determine the portion of fixed cost applicable to the summer and winter seasons, fixed capacity costs were first split into summer and winter portions. The split was based on the ratio of the average of the generation system's four monthly summer peaks (June-Sept) divided by the average of the system's eight monthly winter peaks. (Before the ratio was taken, both average peaks were first reduced by the amount of the system's average annual hourly usage.) This split normally identified about 75% of the costs as being summer-related and 25% as being winter-related. Then the summer-related and winter-related costs were spread to class based on the D10S and D10W allocators, respectively. Those allocators were based on each class participation in the peak hour of system usage, during the summer and winter.

Q. DOES THE COMPANY PROPOSE ANY CHANGES TO THAT METHOD IN THIS CASE?

A. Yes. The method proposed here still identifies the summer-related and winter-related portions of fixed capacity costs but spreads both dollar amounts to class based on D10S. If the system's summer and winter peaks were about the same size, then using both D10S and D10W would have remained more relevant. Since the summer peak is now larger than the winter peak, it is reasonable to apply D10S to both sets of costs for purposes of determining allocation of costs among classes.

Q. ARE THERE ANY OTHER REASONS TO ALLOCATE THE CAPACITY-RELATED PORTION OF FIXED PRODUCTION PLANT TO CLASSES USING ONLY THE D10S ALLOCATOR RATHER THAN AN ALLOCATOR THAT ALSO ACCOUNTS FOR WINTER PEAKS?

A. Yes. Capacity resources are added to the system in order to meet peak demand. The Company meets this peak demand through a combination of Company-owned generation, purchases, and load management programs. Additionally, planning reserves must be added to meet peak demand to ensure reliable system operation in the event of equipment failure. Midcontinent Independent System Operator, Inc.'s (MISO) new adequacy rules that went into effect on June 1, 2013 state that the planning reserve margin requirements must be based on a utility's peak that is coincident with MISO's peak, which is in the summer. I also note that a summer-only allocator only applies to the capacity-related portion of production plant investment; the energy-related portion of production plant is allocated according to the E8760 energy allocator, which accounts for all hours of the year. Overall, this revised allocation approach tries to most closely reflect how Xcel Energy strives to achieve lowest cost capacity planning throughout the year.

Q. DID THIS CHANGE AFFECT ANY CLASS IN PARTICULAR?

A. Yes. This change substantially contributed to the decline in costs for the street lighting class. The CCOSS now indicates that street lighting revenues should be decreased by 16.8%, as compared to an overall jurisdictional increase of 8.0%. Tellingly, this class had 0.94% of the total rate base in the Company's previous rate case (Docket No. EL12-046). Now, it only has 0.76% of the current rate base - which is a 19% drop. Since this class only currently contributes about 1% of total retail revenue, any decrease in their revenue responsibility will have only a minor impact on other classes.

This change is also fitting in a practical sense. At the time of the winter system peak, when the nights are very long, there is a reasonable chance that street lighting load will contribute to the peak. In contrast, during the summer system peak, hours of darkness are fewer, and there is little likelihood that street lighting load will contribute to the system peak load.

Q. PLEASE EXPLAIN HOW THAT LOGIC CARRIES OVER TO THE ALLOCATION OF TRANSMISSION COSTS.

A. Transmission capacity costs were previously allocated on D10T, which was a weighted average of D10S and D10W. To be consistent with the allocation regarding generation capacity, transmission capacity costs are now likewise spread to class based on just D10S, which is coincident with the NSP System peak.

Q. DID THE COMPANY PERFORM ANY STUDIES RELATED TO THE ALLOCATION OF TRANSMISSION PLANT?

A. Yes. We reviewed the allocation of transmission expense within the CCOSS. Our review focused on whether transmission plant should be allocated to the different customer classes using a summer-only allocator.

Q. WHAT WERE THE RESULTS OF THE COMPANY'S ANALYSIS?

A. Our study started by looking at the multiple functions that the transmission system provides. These functions include:

1. Connecting specific generation units to the transmission grid;
2. Bulk Power energy transmission;

3. Linking utility systems to allow for power exchanges and mutual capacity support; and
4. Delivering power to load using markets.

The first three functions are designed to meet the system peak demand, which occurs in the summer. In order to assess the impact that the winter peak has on the fourth function, we identified when 2012 peak demand occurred at each of the 147 substations equipped with SCADA monitoring equipment. Of those 147 distribution substations, only one peaked during the winter months. Based on this analysis, using the D10S allocator is appropriate for this case.

3. Analysis of Other Production O&M Costs

Q. HOW HAS THE COMPANY PREVIOUSLY ALLOCATED OTHER PRODUCTION O&M COSTS?

A. Previously, Other Production O&M costs were first split into fixed and variable proportions (i.e., capacity-related costs vs. energy-related costs). The split was made using original plant production costs, by determining total base load and nuclear fuel plant investments as a percent of total production plant investment. Such costs were deemed to be variable, and usually amounted to approximately 75 percent of the total costs. The remaining 25 percent of costs were presumed to be fixed. Then the variable portion was allocated to class using the E8760 sales allocator, while the fixed portion was allocated to class using the D10C allocator (i.e., a weighted average of the D10S and D10W allocators).

Q. WHY WAS THIS APPROACH USED?

A. There were two reasons. First, the Company realized that a great many costs were included in the Other Production O&M category. Yet, there was no immediate cost pattern that would suggest how the total cost should be allocated. Second, because no other alternative allocator was the obvious choice, it seemed reasonable that Other Production O&M should be allocated in the same manner as the Original Plant investment.

Q. HAS THE COMPANY PROPOSED AN ALTERNATIVE METHOD TO SEPARATE OTHER PRODUCTION O&M COSTS INTO CAPACITY VERSUS ENERGY-RELATED COST CATEGORIES?

A. The Company used the NARUC "Electric Utility Cost Allocation Manual as a guide to develop an alternative method to separate costs. Specifically, pages 64-66 of the manual state the following:

> Typically any costs that vary directly with the amount of energy produced, such as purchased steam, variable water costs and water treatment chemical costs, are classified as energy-related and allocated using appropriate energy allocation factors.
>
> Operations and maintenance costs that do vary directly with energy output may be classified and allocated by different methods.
>
> One common method for handling such accounts is to separate the labor expenses from the materials expenses: labor costs are then considered fixed and therefore demand-related, and material costs are considered variable and thus energy-related.

Using the above guidelines, the Company has separated costs into fixed versus variable components. We examined the entire list of 141 cost item descriptions that make up Other Production O&M costs. These detailed cost descriptions have been combined into a more manageable 15 categories as listed below:

Table 2

Fixed Expenses	**TY2013 Expense**	**Percent (%)**
Employee Labor	$17,694,398	53.89
Contract and Consulting Labor	$9,785,732	29.80
Employee Expenses	$628,598	1.91
Hardware, Software & Networking Exp	$463,567	1.41
License Fees, Permits, Regul Exp & Dues	$2,189,794	6.67
Facilities Maint (Janitorial, Snow, Sewer)	$95,924	0.29
Transportation Fleet Cost	$125,081	0.38
Office Supplies & Equipment	$22,658	0.07
Total Fixed	**$31,005,752**	**94.42%**

Variable Expenses	**TY2013 Expense**	**Percent (%)**
Chemicals	$461,557	1.41
Materials	$3,316,347	10.10
Nuclear Outage Amortization Costs	-$3,110,261	-9.47
Electric Use Costs	$100,910	0.31
Gas Use Costs	$13,303	0.04
Water Use Costs	$14,098	0.04
Steam, Nuke, Hydro Gen Rents	$1,035,425	3.15
Total Variable	**$1,831,379**	**5.58%**
Grand Total Expenses	**$32,837,131**	**100.0%**

Q. HAS THE COMPANY USED THE ABOVE CAPACITY VERSUS ENERGY SPLIT TO ALLOCATE OTHER PRODUCTION O&M COSTS IN ITS PROPOSED CLASS COST OF SERVICE STUDY?

A. Yes, 94.42% of Other Production O&M costs were allocated to classes using just the D10S capacity allocator (to be consistent with the changes discussed above), while 5.58% have been allocated to classes using the E8760 energy allocator.

Q. PLEASE SUMMARIZE THE RESULTS OF THE PROPOSED CCOSS.

A. Table 3 below shows the resulting class cost responsibilities. The detailed CCOSS output is shown on Exhibit___(JPG-1), Schedule 4, and on Exhibit___(NSP-1), Statement O, located in Volume 1. These CCOSS results indicate what change from present rates would be necessary to result in equal cost responsibility for each class. In other words, it is premised on inter-class fairness. Each class of customers should pay all of the operating costs that they incur and should pay for the same rate of return on their share of the rate base.

Table 3

Summary of Class Cost of Service Study ($000)

	UNADJUSTED COST RESPONSIBILITIES					
		Total	**Residential**	**Non-Demand**	**Demand**	**Street Ltg**
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	211,450	92,378	11,131	106,313	1,628
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 6, line 23)	0	0	0	0	0
[3]	Unadjusted Operating Revenues (line 2 + line 3)	211,450	92,378	11,131	106,313	1,628
[4]	Present Rates, w/ Full Riders (CCOSS page 2, line 5)	195,850	82,010	9,934	101,948	1,958
[5]	Unadjusted Deficiency (line 3 - line 4)	15,600	10,368	1,197	4,364	(329)
[6]	Defic / Pres (line 5 / line 4)	7.97%	12.64%	12.05%	4.28%	(16.82%)
[7]	**Ratio: Class % / Total %**	**1.00**	**1.59**	**1.51**	**0.54**	**(2.11)**
	CAPACITY COST RESPONSIBILITIES FOR INTERRUPTIBLE RATE DISCOUNTS					
		Total	**Residential**	**Non-Demand**	**Demand**	**Street Ltg**
[8]	Interruption Rate Discounts (CCOSS page 2, line 2)	(2,764)	(1,276)	(24)	(1,464)	0
[9]	Interruption Capacity Costs (CCOSS page 2, line 3)	2,764	1,136	144	1,484	0
[10]	Revenue Requirement Shift (line 9 - line 8)	0	(140)	120	20	0
	ADJUSTED COST RESPONSIBILITIES					
		Total	**Residential**	**Non-Demand**	**Demand**	**Street Ltg**
[11]	Adjusted Rate Revenue Reqt (line 1 + line 10)	211,450	92,238	11,251	106,333	1,628
[12]	Incr Misc Chrgs & Late Pay (CCOSS page 6, line 23)	0	0	0	0	0
[13]	Adjusted Operating Revenues (line 11 + line 12)	211,450	92,238	11,251	106,333	1,628
[14]	Present Rates, w/ Full Riders (line 4)	195,850	82,010	9,934	101,948	1,958
[15]	Adjusted Deficiency (line 13 - line 14)	15,600	10,228	1,317	4,384	(329)
[16]	Adj Deficiency / Pres (line 15 / line 14)	7.97%	12.47%	13.26%	4.30%	(16.82%)
[17]	TCR & Infrastructure Rider Adjusts (CCOSS page 6, line 8)	9,040	3,190	411	5,371	68
[18]	Adj Pres Revenue, w/ Reduced Riders (line 14 - line 17)	186,810	78,820	9,523	96,578	1,890
[19]	Net Adjusted Deficiency (line 18 - line 13)	24,640	13,418	1,728	9,755	(262)
[20]	Defic / Pres Rates (line 19 / line 18))	13.19%	17.02%	18.15%	10.10%	(13.84%)
[21]	**Ratio: Class % / Total %**	**1.00**	**1.29**	**1.38**	**0.77**	**(1.05)**

More information, including class revenue responsibilities, is shown on Exhibit___(JPG-1), Schedule 6. Class revenue responsibility is further discussed in section III of my testimony.

Q. IN TABLE 3, 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. EL12-046.

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. THE RESULTS SHOW THE RESIDENTIAL AND NON-DEMAND CLASSES' CURRENT RATES ARE FURTHER FROM COST THAN OTHER CLASSES. WHY IS THIS?

A. There are four reasons for the larger impact on the residential and non-demand classes in this case. I discussed the first three above. That is, first, the portion of primary voltage distribution plant that serves 1-phase customers is now being allocated primarily to the residential class, since that class is that plant's main user. Second, the approximately 25 percent of original peaking plant previously allocated on D10W is now allocated on D10S. Due to the heavy use of air conditioning by residential customers, the residential cost responsibility in D10S is slightly higher than in D10W. Likewise, D10S is now the only allocator for transmission plant investment, as well as for the fixed portion of Other Production O&M costs, whereas the previous allocators (D10T and D10C) reflected a blend of D10S and D10W. These changes recognize the greater impact these customers have on the overall costs of service.

Third, Other Production O&M is now being split into 94.42 percent fixed costs and 5.58 percent variable costs, whereas the previous split was closer to 25/75. Due to its modest load factor (i.e., relatively few kWh, as compared to peak demand), the residential class is responsible for approximately 41.1 percent of the D10S allocator (which is used to allocate fixed costs), while the residential class is only responsible for 35.7 percent of the E8760 allocator (which is used to allocate variable costs).

Finally, approximately $9.0 million of costs were previously recovered in the Transmission Cost Recovery (TCR) Rider and Infrastructure Rider. Both riders previously collected costs through a charge per kWh in which all customers paid for these costs based on individual kWh usage regardless of class cost allocation. In contrast, when these costs are included in base rates, allocators are used to allocate retail cost obligation to class. This allocation provides a better matching of costs incurred to those that benefit. In this case, spreading costs to class using customer-based or demand-based allocators gives a higher proportion of cost responsibility to the residential class.

Q. HAS THE COMPANY ALSO UPDATED THE FUEL ADJUSTMENT FACTOR CALCULATION IN THE FUEL CLAUSE RIDER?

A. Yes. I provide the details of the updated fuel adjustment factor in Exhibit __ (JPG-1), Schedule 10.

III. REVENUE ANALYSIS AND ALLOCATION

Q. WHAT ARE THE COMPANY'S EXISTING AND PROPOSED ELECTRIC REVENUES?

A A comparison of the Company's existing and proposed revenues is found in Exhibit ___ (JPG-1), Schedule 6 which provides the sales revenue by rate schedule and Exhibit ___ (JPG-1), Schedule 7, which provides the revenue by rate class. I also provided detailed comparisons of present and proposed revenues in Statement I, found in Volume 1 of the Application.

Q. PLEASE DESCRIBE EXHIBIT __ (JPG-1), SCHEDULES 8 AND 9.

A. Schedule 8 compares present rates to proposed rates both with and without fuel costs (fuel costs for each rate class are also provided). Schedule 9 is a comparison of monthly bills at present and proposed rates for various usage levels.

Q. MR. GILROY, PLEASE PROVIDE A SUMMARY OF YOUR PROPOSED REVENUE ALLOCATIONS.

A. In summary, based on the results of the CCOSS and the proposed rate design, the major customer classes have the following revenue deficiencies and proposed revenue increases:

Table 4

Proposed Revenue Allocations Summary by Class

Class	Total	Res	Non-Dmd	C&I Dmd	St Ltg
Present Retail Rev	195,850	82,010	9,934	101,948	1,958
Adjust Equal Rev	211,450	92,238	11,251	106,333	1,628
Deficiency	15,600	10,228	1,317	4,384	(329)
Percent	8.0%	12.5%	13.3%	4.3%	-16.8%
Pct vs. Total	0.0%	4.5%	5.3%	-3.7%	-24.8%
Proposed Rev Incr	15,599	7,750	964	6,885	(0)
Percent	8.0%	9.5%	9.7%	6.8%	0.0%
Pct vs. Total	0.0%	1.5%	1.7%	-1.2%	-8.0%
Difference	(1)	(2,478)	(353)	2,501	329
Percent	0.0%	-24.2%	-26.8%	57.0%	-99.9%

The Company's proposed revenue allocation is provided on Exhibit (JPG-1), Schedule 6.

Q. HOW WERE THE PROPOSED REVENUE ALLOCATIONS DETERMINED?

A. The Company is focusing on rate continuity in this case. Our initial approach is to increase each class revenue allocation in equal proportions. In this case, that means every class would theoretically get an 8.0% increase. However, where the CCOSS indicated that particular classes had incurred cost obligations that differed substantially from the overall jurisdictional increase, we determined that a modest adjustment in revenue allocations should be made in that direction. For example, the CCOSS suggests that residential rates should increase 12.5%, or 4.5% more than the overall increase. But the proposed increase is 9.45%, or just 1.45% more than the overall increase. Likewise, the CCOSS suggests a 13.3% increase for the non-demand class, which is 5.3% more than the overall increase. But the proposed increase is 9.71%, or just 1.71% more than the overall increase. In the interest of moderation, we are proposing small, incremental changes to bring customer rates closer to the cost of serving each customer group.

IV. RATE DESIGN

A. General Objectives

Q. WHAT GENERAL OBJECTIVES SHOULD GUIDE RATE DESIGN?

A. The Company's pricing proposals are developed according to the following four objectives; namely, that rates should:

1. Produce total revenue that matches the revenue requirement for the test year in order to allow the Company a reasonable opportunity to earn its authorized return on investment;
2. Accurately reflect the resource costs of providing service and, where appropriate, the market value of the service;
3. Provide sufficient flexibility in pricing levels and provisions for our electric service to remain competitive in the broader energy market; and
4. Provide reasonable pricing by considering the importance of rate continuity, customer understanding, revenue stability, and administrative practicality.

Q. Specifically, how did you implement those goals in this case?

A. The Company focused on continuity of the existing rate design. Since a significant portion of the request is related to shifting existing costs from recovery through riders to recovery through base rates, the Company is proposing to change as little of the existing rate design pattern as possible in order to minimize customer confusion. We propose to recover the proposed revenues through a fairly uniform price increase. The exception to this approach is where the increase in a class cost responsibility deviates substantially from the overall, jurisdictional increase.

B. Residential Class

Q. HOW DOES THE IDENTIFIED COST INCREASE FOR THE RESIDENTIAL CLASS COMPARE TO THE OVERALL INCREASE?

A. As noted above, in the CCOSS section, cost responsibility for the residential class increased substantially more than for the remainder of the retail South Dakota customers.

Q. DOES YOUR PROPOSED RESIDENTIAL RATE DESIGN CAPTURE THE ENTIRE COST RESPONSIBILITY FOR THAT CLASS?

A. No. In keeping with the rate design objective of not producing overly large revenue increases, the proposed residential rates move one-third of the way toward full cost responsibility (i.e., 1/3 of the way between an 8.0% and a 12.5% increase).

Q. IN PRACTICAL TERMS, WHAT DOES THIS MEAN?

A. Residential rate structure is quite simple. It is primarily based on an energy charge per kWh, along with a customer charge. To partly close the cost gap for this class, those two items would increase at a rate greater than the overall, jurisdictional increase.

Q. ARE YOU PROPOSING ANY OTHER RESIDENTIAL REFINEMENT?

A. Yes. The total residential class cost responsibility can be broken into customer, demand and energy billing components. Customer-related costs would normally be recovered in the customer charge. The demand-related and energy-related costs would normally be recovered in the energy charge. However, a significant portion of the customer-related costs for this class is currently recovered in the energy charge. Remedying that situation would require raising the residential customer charge to $18.97, as shown on CCOSS page 2, line 18. To make a very modest move toward closing that gap, the Company is proposing a $1.00 increase in the residential customer charge. That represents a customer charge increase of 12.12% for an overhead service customer and 9.76% for an underground service customer, as opposed to the overall proposed class increase of 9.45%.

C. Commercial & Industrial Classes

Q. WHAT OVERALL RATE INCREASE IS BEING PROPOSED FOR THE COMMERCIAL & INDUSTRIAL (C&I) CLASSES?

A. As noted above, the proposed increase for the C&I non-demand class is 9.71%. As for the C&I demand-billed class, it should be noted that they have somewhat more sales than the residential class. Since the proposed residential revenue increase is 9.45%, or 1.45% more than the overall, jurisdictional increase, the C&I demand-billed class must counter-balance that, with a slightly smaller increase. Indeed, the total proposed C&I demand-billed increase would be 6.75%, or 1.25% less than overall.

Q. WHAT IS YOUR PROPOSED C&I RATE DESIGN?

A. All of the customer, demand and energy charges for the C&I classes were increased by approximately the target percent of 6.75 percent.

Q. WERE THERE ANY EXCEPTIONS TO THIS GENERAL APPROACH?

A. The only exception is the Energy Charge Credit (ECC), for demand-billed classes. It rewards customers to the extent that they have above-average monthly load factors. The discount per kWh was raised to 9.53¢ / kWh, relative to the current discount of 7.66¢ / kWh. That represents a 24.4% increase.

Q. WHAT IS THE ENERGY CHARGE CREDIT?

A. The ECC is a per kWh credit that is applied to kWh energy usage above the 360 hours-use (50 percent load factor) level. For a customer with a peak monthly demand of 100 kW, for example, it would apply to energy usage above 36,000 kWh, based on 100 kW times 360 hours. The ECC was established in a few decades ago to reduce that part of the energy charge associated with baseload production capacity costs that are stratified as energy-related, which has a relatively greater effect on customers with high load factors. The stratification process produces a rate design that recovers a higher percentage of costs through energy charges than a non-stratified approach, which is referred to as a "straight fixed variable" (SFV) rate design. The ECC is a mathematical device that automatically provides a moderated portion of SFV savings to higher load factor customers that would benefit from such a rate design.

Q. WHY IS THE PROPOSED INCREASE APPROPRIATE?

A. The proposed ECC recognizes the reduction in energy-related costs, which is the result of a cost shift to demand-related costs. The proposed ECC recognizes the relatively lower level of energy-related cost while allowing for the necessary moderation of a small increase in the proposed base energy rate to an above-cost level.

Q. ARE THE PROPOSED VOLTAGE DISCOUNTS ALSO AN EXCEPTION?

A. No. In general, the voltage discounts are intended to maintain proportional spacing among the customers who are served at different voltage levels. I provide the details of the proposed voltage discount in Exhibit ___ (JPG-1), Schedule 5. If the utility's demand and energy charges doubled over a period of several decades, one would expect the voltage discounts to also double, so as to keep the proper spacing. Thus, the discounts proposed in this case roughly match the overall C&I increase, as shown in the following table:

Table 5

Voltage Discount Analysis

C&I Voltage Discounts – Demand ($ / kW)			
Rate	**Primary**	**Transmission Transformed**	**Transmission**
Present	**$0.70**	**$1.40**	**$2.00**
Proposed	**$0.70**	**$1.35**	**$2.00**
% Change	**0.0%**	**-3.6%**	**0.0%**
C&I Voltage Discounts – Energy (¢ / kWh)			
Rate	**Primary**	**Transmission Transformed**	**Transmission**
Present	**0.109¢**	**0.260¢**	**0.280¢**
Proposed	**0.147¢**	**0.300¢**	**0.320¢**
% Change	**34.9%**	**15.4%**	**14.3%**

D. Street Lighting Classes

Q. WHAT CHANGES ARE YOU PROPOSING FOR THE STREET LIGHTING CLASSES?

A. Similar to the residential class, their total change would only be about 1/3 toward cost. However, that would mean moving 1/3 of the way between an 8.0% increase and a 16.8% decrease. That equates to roughly a 0.0% total change, which is what was proposed. Since rider revenues for these classes will decrease, that necessitated small, offsetting increases in their respective retail rates, so as to achieve the 0.0% change (actually, a 0.02% decrease).

V. TARIFFS

Q. ARE YOU SPONSORING SCHEDULES OF THE PROPOSED TARIFFS AND PROPOSED TARIFF CHANGES?

A. Yes. I sponsor several schedules that provide the proposed tariffs and that identify proposed tariff changes. Those schedules are located in Volume 2 of the Application and are attached to my testimony as follows:

- Schedule 11: Company Tariff Table of Contents
- Schedule 12: List of Proposed Tariff Sheets
- Schedule 13: Summary List of Tariff Changes
- Schedule 14: Rate Schedules and Tariffs (Redlined and non-Redlined)

VI. CONCLUSION

Q. MR. GILROY, PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. In summary, based on the results of the CCOSS and the proposed rate design, the major customer classes have the following revenue deficiencies and proposed revenue increases:

Table 6

Customer Class	Deficiency	Proposed Increase
Residential	12.5%	9.45%
Comm-Ind Non-Demand	13.3%	9.71%
Comm-Industrial Demand	4.3%	6.75%
Street Lighting	-16.8%	-0.02%

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.