Direct Testimony and Schedules
Steven V. Huso

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. EL09-____
Exhibit___(SVH-1)

Rate Design

June 30, 2009

Table of Contents

Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven V. Huso. 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 position is Pricing Consultant.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I develop rate design, revenue determinations, and support other pricing functions for the utility operating subsidiaries of Xcel Energy Inc. I began my employment with Northern States Power Company as a pricing analyst in 1979. I held the position of Administrator-Rate Research from 1992 until I began my current position in 2000, except for the period of 1993 to 1995, when I had the position of Administrator-Pricing for Northern States Power Company-Wisconsin. My qualifications and experience are further described in Exhibit___(SVH-1), Schedule 1.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am providing testimony on behalf of Northern States Power Company, a Minnesota corporation, operating in South Dakota ("Xcel Energy" or the "Company").

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

A. My testimony presents the Company's rate-revenue analysis used to develop retail revenues at present and proposed rates, proposed class-revenue responsibility, and electric rate design proposals. I am also sponsoring the Company's rate schedules and tariffs.

Q. WHAT SCHEDULES ARE YOU SPONSORING IN THIS FILING?

A. My Exhibit___(SVH-1) includes the following schedules:

- Schedule 1 – Statement of Qualifications and Experience
- Schedule 2 – Sales and Revenue by Rate Schedule
- Schedule 3 – Revenue by Rate Class
- Schedule 4 – Summary of Present and Proposed Rates
- Schedule 5 – Monthly Bills Using Present and Proposed Rates
- Schedule 6 – Fuel Clause Service Category Ratios
- Schedule 7 -- Wind Source Rider Calculation

I am also sponsoring several schedules related to the proposed tariff changes along with the tariffs themselves. Those Schedules are located in Volume 3 of the Application.

- Schedule 8 - Company Tariff Table of Contents
- Schedule 9 - List of Proposed Tariff Sheets
- Schedule 10 – Summary List of Tariff Change
- Schedule 11 – Rate Schedules and Tariffs (Redlined)
- Schedule 12 – Rate Schedules and Tariffs (Non-Redlined)

II. RATE REVENUE ANALYSIS

Q. WHAT ARE THE 2008 TEST-YEAR ELECTRIC REVENUES FROM SALES AT PRESENT AND PROPOSED RATE LEVELS?

A. Table 1 below shows 2008 test-year revenues at present and proposed rates for the Electric Utility – South Dakota retail jurisdiction. Revenues are shown for total retail rate revenues and the proposed increase in other revenues. The proposed increase in other revenues represents proposed increases to non-retail charges, which are used to offset a portion of the retail revenue increase.

Table 1
Test-Year Revenue ($1,000's)

	Present	Proposed	Proposed Increase	Percent Increase
Retail Rate Revenue	146,384	164,856	18,472	12.62%
Other Revenue Increases	0	111	111	
Total	146,384	164,967	18,583	12.69%

Ms. Anne Heuer presents the total revenue deficiency in her direct testimony. Test-year revenues are based on an application of test-year sales, supported by Ms. Jannell Marks in her direct testimony, to both present and proposed rates.

Q. HAVE YOU PROVIDED MORE DETAILED COMPARISONS OF TEST-YEAR REVENUES?

A. Yes. I prepared the following summary and detailed comparisons of present and proposed rate revenues:

1. **Sales and Revenue by Rate Schedule**
   - Filed as Exhibit___(SVH-1), Schedule 2
2. **Revenue by Rate Class**

– Filed as Exhibit___(SVH-1), Schedule 3

3. **Sales and Revenue by Rate Schedule and Component**

– Filed in Required Information, Statement I, located in Volume 1 of the Application.

Q. PLEASE DESCRIBE SCHEDULES 4 AND 5 IN YOUR EXHIBIT___(SVH-1).

A. Schedule 4 compares present base rates to proposed base rates both with and without fuel costs. Schedule 5 is a monthly bill comparison of the present and proposed rates at different usage levels.

Q. DO PROPOSED REVENUES RECOVER THE COSTS OF THE TRANSMISSION COST RECOVERY ("TCR") RIDER AND THE ENVIRONMENTAL COST RECOVERY ("ECR") RIDER, TO THE EXTENT THOSE ARE BEING ROLLED INTO THE BASE REVENUE REQUIREMENT?

A. Yes. Proposed revenues were developed to recover the proposed test year revenue requirement, which includes the combined TCR and ECR cost of $2.9 million as discussed in Ms. Heuer's direct testimony. The revenue requirement includes this cost to reflect the Company's proposal to transfer cost recovery from the TCR and ECR Riders to base rates. These Riders became effective February 2009 and customer bills already include recovery of these costs. However, because present 2008 test year revenue excludes rider costs, the proposed revenue deficiency also reflects the increase in the base rate revenue requirement. Showing the proposed revenue deficiency without the impact of rider costs would more precisely represent the actual cost increase associated with this rate case filing, because customers are already paying the Rider costs.

Q. HOW MUCH OF THE PROPOSED RETAIL INCREASE IS ASSOCIATED WITH THE PROPOSAL TO MOVE TCR AND ECR RIDER COSTS INTO BASE RATES?

A. As shown below in Table 2, these Rider costs account for approximately two percent of the proposed increase. However, because customers are already paying these costs through separate TCR and ECR Riders, the net retail average bill impact of the proposed revenue deficiency is a 10.71 percent increase, rather than the proposed 12.69 percent increase.

Table 2
Test-Year Revenue – Rider Impact ($1,000's)

Total Revenue	Present	Proposed	Proposed Increase	Percent Increase
With TCR and ECR	146,384	164,967	18,583	12.69%
TCR and ECR Cost	0	2,900	2,900	
Without TCR and ECR	146,384	162,067	15,683	10.71%

III. CLASS REVENUE RESPONSIBILITY

Q. HOW DID THE COMPANY DETERMINE THE PROPOSED DISTRIBUTION OF CLASS REVENUE RESPONSIBILITY?

A. The primary guideline was the embedded class cost-of-service study ("CCOSS"), sponsored by Mr. Michael Peppin in his direct testimony. Proposed class revenue responsibility is based on a moderate movement towards the CCOSS level, by removing half of class revenue subsidies. I describe this process later in this section of my testimony. The Lighting class increase was further moderated by limiting its increase to the percentage increase proposed for the Residential class. This approach promotes equitable and accurate pricing by minimizing, to the extent practical, revenue subsidies between classes and rate schedules.

Q. PLEASE COMPARE PRESENT AND PROPOSED REVENUES BY SERVICE CLASS WITH THE RESULTS OF THE CCOSS.

A. Revenues by major CCOSS classes are compared in Table 3 below. In the table, class revenue at "cost" is the adjusted revenue requirement from the CCOSS.

Table 3
Retail Rate Revenue by CCOSS Class ($1,000's)

Class	Present	Proposed	Cost	Prop Inc	Prop %
Residential	58,452	66,864	67,939	8,412	14.4%
Non-Demand	8,457	9,640	9,754	1,182	14.0%
C&I Demand	78,095	86,776	85,599	8,681	11.1%
Lighting	1,379	1,576	1,675	197	14.3%
Total Retail	146,384	164,856	164,967	18,472	12.6%
Other Rev Inc.		111		111	
Total	146,384	164,967	164,967	18,583	12.7%

Q. IS THE PROPOSED 14.4 PERCENT RESIDENTIAL CLASS INCREASE REASONABLY MODERATE COMPARED TO THE 12.7 PERCENT AVERAGE RETAIL INCREASE?

A. Yes. The 14.4 percent increase is 1.7 percent more than the average increase of 12.7 percent. It would have required a 16.2 percent increase for Residential revenues to equal the cost of service. Thus, the modest 1.7 percent differential represents only half of the 3.5 percent differential between an average increase and the increase that would set revenues at the cost of service. The proposed increase appropriately provides a key step towards recognizing actual cost responsibility. Taken in the context of Residential base energy rates that have not changed for over 16 years, the proposed differential represents a small average annual change.

Q. WILL OTHER FACTORS MITIGATE THE PROPOSED 14.4 PERCENT RESIDENTIAL CLASS INCREASE FOR THE 2008 TEST YEAR?

A. Yes. The actual customer impact of implementing the proposed 14.4 percent Residential increase is reduced by the transfer of the currently separate TCR and ECR Rider charges into base rates and the proposed crediting of wholesale margins to fuel costs. As discussed above, the Rider transfer reduces the effective proposed rate increase by approximately two percent. As discussed in Ms. Heuer's direct testimony, the wholesale margin proposal has the appearance of increasing retail rates by $1.8 million, or 1.2 percent. Also, system average fuel costs are 10 percent lower through May of this year than the corresponding period of the 2008 test year. This average cost decrease of 0.27¢ per kWh is directly passed through to customers through the Fuel Clause Rider. If this cost decrease were sustained, on an annual basis it would reduce the proposed Residential class increase by approximately three percent. A six percent decrease to the proposed Residential increase, which is the combined impact of the Rider cost transfer, wholesale margin credits, and a sustained fuel cost decrease, would substantially mitigate residential bill impacts.

IV. RATE DESIGN OBJECTIVES

Q. WHAT ARE THE COMPANY'S OBJECTIVES WHEN DEVELOPING ITS ELECTRIC RATE STRUCTURE?

A. The following are the Company's main electric rate design objectives:

1. Yield total revenues equal to Test Year revenue requirements, to provide a reasonable opportunity for the Company to earn its authorized return on investment.
2. Accurately reflect the resource costs of providing service and, where appropriate, reflect the market value of provided services.
3. Provide sufficient flexibility in pricing and associated conditions of service to maintain competitive electric service in the broader energy market.
4. Achieve practical objectives of reasonable rate continuity, customer understanding, revenue stability, and administrative reasonableness.

Q. HAS THE COMPANY USED MARGINAL COSTS IN ITS RATE DESIGN IN ORDER TO ACHIEVE THESE OBJECTIVES?

A. Yes. Proposed rates reflect marginal costs to advance the rate design objective of accurately reflecting the resource costs of providing service. Marginal costs are directly applied to proposed rates in areas such as time-of-day ("TOD") energy charge ratios. Proposed rate levels and relationships also are directly influenced by the CCOSS, which makes significant use of marginal cost information, including system hourly marginal energy costs. The use of marginal cost in the CCOSS is discussed in the direct testimony of Mr. Peppin. The Company also uses marginal cost analysis as a guide in developing interruptible rate programs and for evaluating their cost-effectiveness. The Company also uses marginal cost information in establishing purchase power rates offered to customers who are small power producers.

V. RATE DESIGN PROPOSALS

Q. PLEASE SUMMARIZE YOUR RATE DESIGN TESTIMONY.

A. My rate design testimony discusses material changes in the design and level of proposed rates. My testimony does not include a discussion of proposed changes in rate levels that only represent proposed revenue responsibilities with no significant change in rate design.

A. Fuel Clause Rider

Q. IS THE COMPANY PROPOSING CHANGES TO ITS FUEL CLAUSE RIDER TARIFF?

A. Yes the Company is proposing a number of revisions to its Fuel Clause Rider ("FCR") tariff. The tariff title has changed to Fuel Cost Rider to more clearly describe its purpose. Proposed structural changes to the FCR mechanism are described in detail below. The proposed changes are driven by the following considerations:

1. The need to accurately allocate to customers their cost of fuel and purchased energy costs, particularly as those costs change over time.

2. The growing interest in a one-part fuel cost charge (combining into a single rate what was previously the base cost of energy and the monthly adjustment). The fuel cost charge would be itemized on customer bills along with the separate base energy charge. No fuel costs would be recovered through base energy charges.

3. The need for a mechanism to support sharing with retail customers the wholesale margins resulting from intersystem sales transactions on a current actual basis rather than a fixed test year basis.

4. The need to refine and clarify the language of the FCR tariff to make it easier to understand what costs are included and the basic mechanics of the tariff.

Q. PLEASE SUMMARIZE HOW XCEL ENERGY'S CURRENT FCR TARIFF WORKS.

A. As a part of general rate case filings, updated test year costs of fuel and purchased energy are established and allocated to customer classes. In previous rate cases, the updated fuel cost allocation has been included in the energy charges of each tariff, along with other energy-related costs. The updated base cost of fuel is converted into a system average fuel cost per kWh. After new base rates were implemented, the difference between the ongoing fuel costs and the test year "base" cost of fuel is defined as the current monthly fuel adjustment charge. This fuel adjustment charge, combined with the base fuel cost included in base energy charges, would provide recovery of total fuel costs.

Specifically, actual fuel and purchased energy costs (using a rolling 2-month average) would be compared to the test year "base" cost of fuel, and the difference becomes the primary element in the Fuel Clause Adjustment ("FCA") charge for the next month. The other element in the FCA is the "true-up" factor, which is a fine-tuning mechanism that reconciles fuel costs and revenues from previous months.

Q. IS THERE A CONCERN ASSOCIATED WITH THIS CURRENT METHOD?

A. The present FCR mechanism worked very well for decades when fuel cost changes were less dramatic than in recent years. However, rapid changes in fuel cost levels, and the extended periods between general rate cases when base fuel costs and class cost allocations are updated, have reduced the precision of class cost responsibility when recovering fuel costs because changes in fuel cost were recovered between rate cases using a single average per kWh charge that is applied to all customers. Consequently, between rate cases a higher percent of fuel costs have been recovered through monthly FCA charges that do not recognize the class cost differences that are recognized in base energy charges.

Q. COULD YOU ELABORATE ON THIS CONCERN?

A. Let me begin by explaining what is not a concern. The concern is not with the FCR base cost. Historically, this component of the FCR recovered the bulk of total costs because the monthly FCAs were small. Furthermore, the FCR base cost is accurately allocated to classes based on the different class use patterns and marginal energy cost relationships. The classes' cost responsibilities resulting from this approach were then built into the energy charges of each tariff.

The concern arises because of the high monthly FCAs that have occurred in recent years. The FCAs are the difference between the actual average-system-cost per kWh and the test year FCR base cost. Because the FCAs are directly applied to kWh usage, that portion of fuel cost recovery does not reflect class cost differences.

Historically, this method of recovering the actual deviations from test year FCR base costs was reasonable and appropriate. Deviations were small and more frequent rate cases provided timely re-allocation of any sustained cost deviations from the previous test year FCR base cost. Furthermore, the simplicity of the method made it easy to understand and efficient to administer.

However, in recent years market-driven fuel and purchased energy costs have escalated rapidly, and the interval between rate cases has been more extended. The result has been that customer classes that use relatively more energy during off-peak periods pay too much through these FCAs. Conversely, classes with relatively more on-peak use pay too little.

Q. WHAT CHANGES IN THE FCR TARIFF ARE PROPOSED TO ADDRESS THIS CONCERN?

A. The Company's proposed changes can be summarized as follows:

1. Eliminate the current two-part FCR structure, which includes a test year FCR base cost and a monthly FCA, which tracks cost deviations from the FCR base cost.

2. Replace it with a one-part FCR structure where each month, total fuel and purchased energy costs are determined and divided by system sales, to yield a system average Fuel Cost Factor ("FCF").

3. Apply "Service Category Ratios" (specific to the six service categories described below) to this system average FCF, to obtain service-category-specific FCFs.

4. Apply the service category specific FCFs to individual customer kWh use to obtain a total Fuel Cost Charge ("FCC") shown on the customers' bill.

The "Service Category Ratios" for 3 of the 4 primary classes (i.e. Residential, Commercial and Industrial ("C&I") Non-Demand and Outdoor Lighting), are the same as the "Class Ratios," which are developed directly from the proposed E8760 energy allocator, which is described in Mr. Peppin's direct testimony.

For the 4th primary class (C&I Demand), the E8760-derived "Class Ratio," is further de-averaged into three separate "Service Category Ratios," one each for the "Service Categories" of: (1) Non-TOD; (2) On-Peak TOD; and (3) Off-Peak TOD. The de-averaging of the C&I Demand "Class Ratio" is based on the TOD usage of the Non-TOD and TOD customer groups and a TOD energy cost ratio.

Q. PLEASE ELABORATE ON HOW THESE ELEMENTS WOULD BE APPLIED TO PRODUCE THE SERVICE-CATEGORY-SPECIFIC FCFS.

A. This mechanism is straightforward. For each service category, a fixed allocation cost ratio is applied to average system fuel cost for each month. These Service Category Ratios represent cost relationships that provide appropriate fuel charges for each service-category. This process extends to future fuel costs the same cost allocation that is currently restricted to the base cost of fuel as defined in the last test year. The advantage of this mechanism is that going forward from the test year, all fuel costs will be accurately allocated to customer classes. The mechanics of this method are provided in my Schedule 6 of Exhibit___(SVH-1), which itemizes the development of the "Service Category Ratios." The resulting Service Category Ratios are summarized in the below table.

Table 4
Proposed Fuel Adjustment Factors

Service Category	FAF Ratio
Residential	1.0094
C&I Non-Demand	1.0332
C&I Demand Non-TOD	1.0108
C&I Demand TOD On-Peak	1.3158
C&I Demand TOD Off-Peak	0.7510
Outdoor Lighting	0.8171

Q. DOES THIS NEW ONE-PART FCR MECHANISM RESULT IN A DIFFERENT PRESENTATION OF FUEL COSTS UNDER PROPOSED RATES AS COMPARED TO PRESENT RATES?

A. Yes. For example, in the past, the Residential tariff included: (1) the customer charge; (2) the energy charge (that included among other costs, the test year FCR base fuel cost); and (3) the FCA charge, which included only the fuel cost deviations from the FCR base fuel cost.

Under our proposed FCR tariff, the energy charge will not include any fuel costs. All fuel and purchased energy costs are instead presented in one separate component in the tariffs and on customers' bills.

Q. ARE ANY SPECIFIC COMMISSION AURTHORIZATIONS NECESSARY TO IMPLEMENT THE COMPANY'S PROPOSED FCR MECHANISM?

A. Generally, the Commission would need to approve the method described above and illustrated in Schedule 6 of Exhibit___(SVH-1). The specific approvals would include: (1) authorization to eliminate the current two-part FCR mechanism (i.e. "base" cost with FCA deviations from the "base"); and

(2) authorization to implement the proposed one-part FCR mechanism, which includes the use of six service category FCFs, which are derived from the average system costs of fuel and purchased energy.

Q. IS THE COMPANY REQUESTING A WAIVER OF ANY SOUTH DAKOTA RULES IN ORDER TO IMPLEMENT THE PROPOSED CHANGES TO THE FCR?

A. It is our belief that a waiver of South Dakota Rules is unnecessary. The rules do not address the allocation of costs between classes, which is the primary change we are propose, nor does charging a single fuel rate compared to the current process of recovering the cost through two cost components change the amount charged the customer. However, if the Commission's interpretation of the applicable South Dakota Rules is such that it believes a waiver is necessary, then the Company requests such a waiver.

Q. ARE THERE OTHER TARIFF REVISIONS NEEDED TO ACCOMMODATE THE COMPANY'S PROPOSED NEW ONE-PART FCR MECHANISM?

A. Yes. As I indicated earlier, the "energy charge" components of all the current tariffs include the FCR base costs of fuel. And the monthly FCAs are a second separate rate component. However, under the Company's proposed tariffs, this FCR base cost and the monthly FCAs are added together and this total is charged as a separate one-part fuel cost charge ("FCC"). This change in the FCR structure requires minor language changes in the following tariffs: (1) Residential Controlled Air Conditioning & Water Heating Rider, and (2) Time of Delivery Purchase Service.

Q. PLEASE DESCRIBE THE LANGUAGE CHANGE IN THE RESIDENTIAL CONTROLLED AIR CONDITIONING & WATER HEATING RIDER?

A. The Residential Controlled Air Conditioning & Water Heating Rider ("Saver's Switch") has a provision that refers to the Saver's Switch discount applying to the "energy charge" of a corresponding service tariff. The current "energy charge" includes the FCR base cost. In order for the Saver's Switch discount to function as intended, the language must be modified to make it clear that the discount now applies to energy and fuel cost charges.

Q. WHAT CHANGE IS NEEDED FOR THE TIME OF DELIVERY PURCHASE SERVICE RATES?

A. This tariff specifies payments from the Company to customers for energy supplied from customers' small generators. This tariff includes a "Fuel Clause" provision. The effect of this provision is to add the FCA (FCC under the proposed tariff) to the purchased energy payment that is separately listed. The purchased energy payment is based on the Company's avoided costs (marginal costs) and as such is already fully compensatory.

Therefore, to avoid significant over-payment for energy purchased under these contracts, the current FCA or the proposed FCC payment should be eliminated. Leaving this provision in place, especially with the new FCC, would result in substantial over-payment for energy purchased under these tariffs. The resulting payment would include the Company's total average fuel and purchased energy costs on top of the avoided cost payment. The proposed language changes for these tariffs are shown in redline format in Schedule 11 of the Proposed Tariffs in the Company's filing.

Q. DOES THE COMPANY'S PROPOSED FCR TARIFF INCLUDE ANY OTHER SIGINFICANT REVISIONS?

A. Yes. The Company is proposing a different method for sharing intersystem sales margins with customers than has been used in the past. This change is discussed in the direct testimony of Ms. Heuer.

Q. PLEASE EXPLAIN THIS DIFFERENT METHOD FOR SHARING INTERSYSTEM SALES MARGINS.

A. In the past, a fixed test year amount of margins obtained from intersystem energy sales was applied to the revenue requirements, which lowered the base rate revenue requirements for retail customers. In this case, the Company is proposing a new method for sharing asset-based margins from intersystem sales with the retail customers.

The new proposal is to credit 100 percent of these intersystem sales asset-based margins with customers by means of a credit to the monthly FCR cost recovery mechanism and to do so on an actual basis as the asset-based margins are earned. On an annual basis, we propose crediting 25 percent of the margins from non-asset based sales, as more fully described in the direct testimony of Ms. Heuer. This margin credit mechanism is described in detail in the Company's proposed FCR tariff.

Q. YOU INDICATED EARLIER THE NEED TO MAKE SOME LANGUAGE REVISIONS IN THE FCR TARIFF TO MAKE IT EASIER TO UNDERSTAND. DOES THE COMPANY'S PROPOSED FCR TARIFF INCLUDE THESE ADDITIONAL LANUGUAGE CHANGES?

A. Yes, all of the proposed language changes in the FCR tariff are shown in the red line version of the filed tariffs, my Schedule 11, located in Volume 3 of the Application. The language changes include the changes necessary to implement the proposed new one-part FCR mechanism and the new method for sharing wholesale margins. These two significant revisions account for the bulk of the language changes. The Company has also made other less substantive language changes, the purpose of which is to make the somewhat complex FCR tariff a little easier to understand.

B. Residential Service

Q. DOES THE PROPOSED RATE DESIGN MODIFY THE WINTER DECLINING BLOCK ENERGY CHARGES?

A. Yes. Present Residential energy charges are flat during the summer months of June through September, and include a declining block during other months for usage over 1000 kWh. Proposed energy charges extend the flat summer energy rate design to all months of the year. The present winter rate differential – the rate decrease for usage over 1000 kWh per month – is 0.51¢ per kWh for residential customers without electric space heating and 1.98¢ per kWh for residential electric space heating customers. As I describe later, we do, however, propose a lower winter energy rate for electric space heating customers coupled with a higher customer charge.

Q. WHY IS THE COMPANY PROPOSING THIS CHANGE?

A. A declining block rate structure does not accurately reflect the cost of service and may encourage higher energy usage, which can result in higher system costs over time. Flat energy rates are proposed to replace the present winter declining block rate structure.

Q. WHAT OTHER CHANGES IN THE RESIDENTIAL RATE DESIGN ARE PROPOSED?

A. The Residential Service customer charge for overhead service is proposed to change from $6.55 to $7.50 per month. This 14.5 percent customer charge increase is close to the proposed 14.4 percent increase overall for the residential customer class. This proposed customer charge provides more equitable pricing by moving the Residential customer charges closer to the Residential customer cost of $17.93 per month, as shown in the CCOSS. This customer charge increase also will mitigate the impact of moving to flat winter energy rates on higher usage customers without space heating, by increasing slightly the bills paid by lower usage customers and reducing the effect of the increase on higher usage customers.

Q. IS THE SEPARATE RATE STRUCTURE FOR ELECTRIC SPACE HEATING CUSTOMERS RETAINED IN THE PROPOSED RESIDENTIAL SERVICE TARIFF?

A. Yes. The present tariff includes a lower winter end-step energy rate for electric space heating customers, which recognizes the lower average cost per kWh of electric space heating usage. The proposed tariff continues to recognize this cost difference through the combination of a flat winter energy rate that is 1.20¢ per kWh less than the proposed standard winter energy rate and a $3.00 higher customer charge.

Q. WHY IS A HIGHER CUSTOMER CHARGE PROPOSED FOR ELECTRIC SPACE HEATING CUSTOMERS?

A. During the winter months (October through May), the proposed tariff applies a lower space heating energy rate to all energy use, as opposed to only usage over 1000 kWh. The higher customer charge allows a lower winter energy rate by reducing the over-recovery of customer-related costs that would otherwise occur as a result of the higher winter kWh usage of electric space heating customers. This over-recovery results from the significant amount of customer-related costs that are recovered though the energy charge. An additional benefit of the higher customer charge is that it provides a disincentive to non-space heating customers requesting service as a space heating customer in order to receive the lower electric space heating rate. This disincentive occurs because the higher customer charge is not offset by the lower energy rate savings at the lower energy usage levels that are more typical of customers that do not use electric space heating.

Q. IF THE ELECTRIC SPACE HEATING CUSTOMER CHARGE WERE SET TO BE THE SAME AS THE NON-SPACE HEATING CUSTOMER CHARGE, WHAT AFFECT WOULD THAT HAVE ON THE ENERGY CHARGE?

A. A slight increase to the present winter declining block rate differential would be required. The Company's proposed flat rate design provides is simpler, and better reflects cost.

Q. IS THE PROPOSED REVENUE INCREASE DIFFERENT FOR ELECTRIC SPACE HEATING CUSTOMERS?

A. Yes. The proposed revenue increase is 12.1 percent for electric space heating customers and 14.5 percent for without electric space heating. The proposed total Residential average increase is 14.4 percent. This space heating rate differential is supported by the CCOSS, which shows revenue deficiencies of 11.6 percent for space heating and 15.3 percent for non-space-heating customers.

Q. PLEASE EXPLAIN THE PROPOSED CONSOLIDATION OF SEPARATE RESIDENTIAL RATE SCHEDULES FOR OVERHEAD AND UNDERGROUND SERVICE.

A. The Company proposes combining the separate underground service rate schedules for non-TOD and TOD rates into the existing overhead service rate schedules. The two Residential underground tariffs are identical to the corresponding overhead tariffs except the customer charge is $2.00 per month more for underground service. By adding another Customer Charge line to the otherwise identical tariffs, the two separate underground versions can be eliminated. The Company proposes this consolidation for efficiency and simplicity.

Q. WHY IS THE COMPANY PROPOSING TO ELIMINATE OPTIONAL PEAK PERIODS FOR RESIDENTIAL TOD SERVICE?

A. The optional peak periods have not helped attract Residential customers to TOD service and are less important to the cost basis for TOD service.

C. General Service and General Time-of-Day Service

Q. PLEASE EXPLAIN THE PROPOSED RATE DESIGN FOR GENERAL SERVICE AND GENERAL TOD SERVICE.

A. The proposed rates retain the present rate design of equal demand charges and equivalent energy charges for General Service and General TOD Services. The present seasonal demand charge differential of $2.61 per kW was increased to $3.00 per kW to better reflect seasonal cost differences. The proposed 1.60 ratio of on-peak to off-peak TOD energy rates is an increase from the present 1.33 ratio, but also moderated from the 1.75 ratio of marginal energy costs.

D. Peak-Controlled and Peak-Controlled Time-of-Day Services

Q. PLEASE EXPLAIN THE TWO OPTIONS FOR THE CONTROLLABLE DEMAND CHARGE COMPONENT OF THE PEAK-CONTROLLED AND PEAK-CONTROLLED TOD SERVICES.

A. There are two sets of controllable demand charge options, which are applied to an interruptible customer's controllable kW demand. Option A controllable demand charges are the same every month, which produces a higher summer controllable demand discount (firm demand charge less the controllable demand charge) relative to seasonal firm demand charges. Option B controllable demand charges, which have been closed to new load since at least 1993, have the same seasonal differential as firm demand charges. Consequently, the resulting Option B controllable demand discounts are not seasonally differentiated, but are the same each month.

Q. WHY IS THE COMPANY PROPOSING TO CANCEL OPTION B CONTROLLABLE DEMAND CHARGES?

A. Option B was closed because it did not provide the seasonal controllable demand discounts that recognize the higher value of controllable demand during summer months. Therefore, Option B over-compensates interruptible service customers that have higher controllable demand levels outside of summer peak season months. With less than five percent of controllable demand billed under Option B, it is now reasonable to cancel this option.

E. Real-Time Pricing

Q. DOES THE COMPANY HAVE A REAL-TIME PRICING ("RTP") RATE OPTION AVAILABLE IN SOUTH DAKOTA?

A. No. The Company has had an RTP option available for larger customers (over 1000 kW) in Minnesota and Wisconsin since 1996, and established that option in North Dakota earlier this year. However, RTP has not been a widely accepted rate option – currently in the available states, a total of three customers are receiving RTP service (two of these customers have multiple accounts).

Q. WOULD THE COMPANY BE WILLING TO ESTABLISH RTP SERVICE IN SOUTH DAKOTA?

A. Yes. Although RTP is a complex rate option to develop and administer, the Company would be willing to propose establishing RTP service if the Commission or any qualifying South Dakota customers expressed a significant interest. A challenging RTP issue for the Company, however, is the resulting reduced revenue without offsetting cost reductions. As an optional rate, customers typically select RTP if existing load patterns are able to offset the additional perceived risk of its more variable and less certain pricing.

F. Street Lighting Service – Purchased Equipment

Q. ARE ANY REVISIONS PROPOSED TO THE SERVICES AVAILABLE UNDER THE STREET LIGHTING SERVICE – PURCHASED EQUIPMENT TARIFF?

A. Yes, some service "Groups" were canceled. The Company proposes to cancel the Group II and Group III service distinctions, which are no longer used by any customers. Current rates for Group II and Group III services are priced at the Group I rates less a small discount. The Group II service distinction is the use of ballglobe glassware or nonstandard ballasts in place of standard equipment. The Group III service distinction is that the customer supplies the glassware and ballast.

G. Windsource Energy Rider

Q. IS THE COMPANY PROPOSING A NEW OPTION THAT WILL ALLOW CUSTOMERS TO PURCHASE RENEWABLE ENERGY?

A. Yes, the Company is proposing a Windsource Energy Rider that is similar to the Windsource programs it offers in Minnesota, Wisconsin and Colorado. The new tariff will give customers the opportunity to voluntarily purchase some or all of their electrical energy from renewable resources. The proposed new Windsource Energy Rider tariff is included in Schedule 11, Volume 3 of the Application.

Q. WILL THIS PROGRAM IMPOSE ANY COSTS ON NON-PARTICIPATING CUSTOMERS?

A. No. It is structured to recover all program costs only from participating customers through a voluntary renewable energy charge. No incremental program costs are charged to other customers.

Q. HOW IS THE PROPOSED WINDSOURCE ENERGY RIDER STRUCTURED?

A. The Windsource Energy Rider allows customers to purchase renewable energy in blocks of 100 kWh. The minimum commitment period is one year for residential customers and three years for commercial and industrial customers. The proposed Windsource rate is 3.60¢ per kWh, as shown in Exhibit No.___(SVH-1), Schedule 7, Page 1 of 2. This charge is in addition to the standard rate, with the exception that the fuel cost charge from the FCR Rider does not apply to the Windsource energy use because it replaces conventional energy sources.

The result is that the net incremental cost of Windsource energy (as compared to conventional energy) will vary from month to month as the comparison to the FCR fuel cost rate changes. However, as an example, Windsource energy would be approximately 0.76¢ per kWh more than the combined standard Residential energy rate and the average FCR cost of 2.84¢ per kWh.

Q. WILL WINDSOURCE ALWAYS COST MORE THAN REGULAR RATES?

A. Not necessarily. Windsource reflects annual costs, while the FCR reflects a two-month moving average cost. The average annual FCR cost is expected to be less than the Windsource price, but that may not be true for every month – particularly for summer months that typically have higher fuel costs. In the Company's other Windsource states, during months when the FCR price exceeded the Windsource price, this led some non-participants to the misunderstanding that "Windsource is cheaper than the regular rate." Some of these customers then switched to Windsource, based solely on price, only to be disappointed in the long run due to lack of savings. The Company now tries to inform potential Windsource customers to not be misled by monthly price swings.

Q. HOW WOULD THE "COST TRACKER" BE USED TO SET THE WINDSOURCE PRICE?

A. As indicated in the Windsource Energy Rider, the Company will maintain a monthly "cost tracker" of program revenues and expenses. The Company would file the tracker balance annually with the Commission each October 1st, starting in 2011. This timing would allow any proposed revised price to be placed in effect for the following calendar year. The Company would seek to adjust the Windsource Energy Rider rate to reflect significant changes in forecasted costs. Such a revised price would include a "true up" of the tracker balance for any over- or under-recovery of prior period costs, along with interest.

Exhibit___(SVH-1), Schedule 7, Page 1 of 2, (referred to previously) shows the "pro forma" tracker for 2010 and is the basis for the Company's proposed Windsource Energy Rider rate of 3.60 cents per kWh. Note that by applying this rate, the year-to-date (YTD) tracker value in the lower, right corner ends with a value of zero, reflecting that the proposed rate would recover current costs.

Q. WHAT COST COMPONENTS ARE INCLUDED IN THE WINDSOURCE ENERGY RIDER?

A. The largest cost component in the Windsource Energy Rider is the cost of the renewable energy itself. However, as can be seen from the "pro forma" tracker, the rate also includes marketing and administration costs. The rate also includes a capacity credit to renewable energy costs. This credit recognizes the added value of capacity that the incremental renewable energy brings to the total system, which would otherwise be acquired through construction or purchases of additional peaking capacity. The credit is calculated in Exhibit___(SVH-1), Schedule 7, Page 2 of 2, based on the latest information from the Midwest Independent Transmission System Operator ("MISO"), of which Xcel Energy is a member.

Q. WOULD CUSTOMERS ACTUALLY RECEIVE 100% "GREEN ELECTRONS?"

A. No. The Company, of course, cannot track individual electrons. Even if tracking were possible, it would reveal a chaotic assortment of electrons from all types of generating sources. Further, the variable nature of renewable generation resources would continuously change the production output of the facilities dedicated to this Rider, to levels above and below subscribed capacity. During shortfalls, Rider customers would "borrow" electricity from non-renewable generation. During times of excess renewable production, this program would not only meet subscribed levels, but would offset the debt to traditional generation. Rather than an expectation of receiving 100% green electrons, the Company would encourage Windsource customers to use the more relevant standard of the net annual effect. During the course of a year, a Windsource customer's revenue will produce incremental green power for Xcel Energy's overall system.

Q. HOW CLOSELY WILL THE RIDER'S ANNUAL PRODUCTION MATCH SALES?

A. In the early years of the Minnesota Windsource program, it was difficult to match program production with sales. When an entire wind farm was dedicated to the program, it often caused a quick, lumpy swing from under-supply to over-supply. However, the Company has recently adopted a smoother and more precise approach that dedicates only a certain percentage of a new wind farm to the Windsource program. In future years, a higher percentage of a given wind farm can be dedicated as required to match sales. This approach does not guarantee a perfect annual match, but is a significant improvement.

Q. HOW WOULD RENEWABLE ENERGY CREDITS ("RECS") APPLY?

A. RECs are purchases of renewable energy from other producers. Prior to using the improved matching approach discussed above, the Company realized it could experience multi-year supply shortfalls. To expedite the balancing of program production and sales, the program was designed with a REC option to allow the Company to purchase enough RECs to offset shortfalls. Although the electricity associated with shortfalls was generated in traditional non-renewable power plants, the purchased RECs would "turn brown power green." While RECs were typically associated with green power produced outside the Company's service territory, the Company understands that Windsource program participants would still prefer restricting the supply of Windsource electricity to the Company's renewable resources. Going forward, the Company hopes its new method will allow that, but it still believes that the REC option should be retained.

Q. WHAT SUPPLY SOURCES WOULD THE PROGRAM EMPLOY?

A. This Rider's primary electric source would be wind. But other renewables, such as solar and biogas, could eventually be included.

Q. WHAT PARTIES WOULD OWN THIS RIDER'S RESOURCES?

A. Power Purchase Agreements ("PPAs") negotiated with third parties would supply the initial renewable electricity. But in the future, the Company expects to directly own a reasonable share of this Rider's total supply.

VI. TARIFFS

Q. ARE YOU SPONSORING THE PROPOSED TARIFFS?

A. Yes, I am. My Schedule 11 is a copy of the proposed tariffs in legislative format. My Schedule 12 is a copy of the proposed tariffs in non-legislative format. The tariffs are located in Volume 3 of the Application

Q. HAVE YOU PREPARED OTHER SCHEDULES RELATED TO THE PROPOSED TARIFF CHANGES?

A. Yes. My Schedule 8 is the Company Tariff Table of Contents; Schedule 9 is a List of Proposed Tariff Sheets; and Schedule 10 is a Summary List of Tariff Change. These are also located in Volume 3 of the Application.

VII. CONCLUSION

Q. CAN YOU PLEASE SUMMARIZE YOUR CONCLUSIONS?

A. The proposed distribution of revenue requirements by major customer class is reasonable and provides a moderate movement toward the cost of service. The Company's proposed rates are reasonable, consistent with its rate design objectives, and improve customer equity.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications and Experience

Steven V. Huso

I graduated from St. Olaf College in 1976 with a Bachelor of Arts degree in Mathematics and Economics. In 1979, I graduated from the University of St. Thomas with a Master of Business Administration degree.

I am currently employed as a Pricing Consultant with Xcel Energy. In 1979, I began employment as a pricing analyst with Northern States Power Company, now Xcel Energy. I had the position of Administrator-Rate Research from 1992, until I began my current position in 2000, except for the period of 1993 to 1995, when I held the position of Administrator-Pricing for Northern States Power Company-Wisconsin.

My job responsibilities include developing rate design, revenue determinations, and pricing function support for the utility operating subsidiaries of Xcel Energy. I have also developed several papers and a book chapter on electric utility pricing issues.

I have sponsored rate design testimony in proceedings before state regulatory commissions in Minnesota, North Dakota, South Dakota, Wisconsin, and Colorado.

Northern States Power Company, a Minnesota Corporation | Docket No. EL09-___
Electric Utility - South Dakota | Exhibit No. ______(SVH-1), Schedule 2
Test Year Ending December 31, 2008 | Page 1 of 1

SALES AND REVENUE BY RATE SCHEDULE

Service Schedule	Average Customers	MWH Sales Summer	MWH Sales Winter	MWH Sales Annual	Revenues ($1,000's) Summer Present	Summer Proposed	Winter Present	Winter Proposed	Annual Present	Annual Proposed	Increase Amount	Increase Percent
Residential												
Residential	69,876	237,711	399,747	637,458	22,802	25,919	35,504	40,773	58,306	66,692	8,385	14.38%
Resid Heat Pump	67	241	934	1,175	20	22	54	65	74	87	13	17.74%
Load Management	90	222	1,062	1,283	14	16	59	69	72	85	13	18.21%
Res Total	**70,034**	**238,174**	**401,742**	**639,916**	**22,835**	**25,957**	**35,617**	**40,907**	**58,452**	**66,864**	**8,412**	**14.39%**
C&I - Non-Demand												
Small General	7,087	32,519	65,842	98,362	2,995	3,427	5,401	6,143	8,396	9,570	1,174	13.99%
Small General TOD	34	185	460	645	15	17	33	38	48	55	7	14.47%
Load Management	7	54	85	139	5	5	7	7	11	12	1	7.35%
C&I N-D Total	**7,128**	**32,759**	**66,387**	**99,146**	**3,014**	**3,449**	**5,441**	**6,188**	**8,455**	**9,637**	**1,182**	**13.98%**
C&I - Demand												
General	2,767	226,738	404,387	631,126	17,201	19,226	27,612	30,745	44,813	49,971	5,158	11.51%
General TOD	140	134,147	237,245	371,392	8,411	9,279	13,647	14,950	22,058	24,229	2,171	9.84%
Peak-Controlled	68	18,740	38,886	57,626	1,407	1,588	2,654	2,986	4,061	4,574	513	12.63%
Peak-Controlled TOD	9	30,193	39,296	69,489	1,745	1,922	2,194	2,430	3,938	4,352	414	10.51%
Energy-Controlled	31	21,135	39,724	60,859	1,128	1,277	2,097	2,372	3,225	3,650	425	13.18%
C&I Dmd Total	**3,014**	**430,954**	**759,537**	**1,190,491**	**29,892**	**33,293**	**48,203**	**53,483**	**78,095**	**86,776**	**8,681**	**11.12%**
C&I Total	**10,142**	**463,713**	**825,925**	**1,289,637**	**32,907**	**36,743**	**53,644**	**59,671**	**86,550**	**96,413**	**9,863**	**11.40%**
Public Authorities												
Siren Service	0	0	0	0	1	1	2	2	2	3	0	9.62%
PA Total	**0**	**0**	**0**	**0**	**1**	**1**	**2**	**2**	**2**	**3**	**0**	**9.62%**
Lighting												
System Service	0	438	1,230	1,668	159	188	317	376	476	564	88	18.38%
Energy	0	1,160	3,333	4,492	85	99	204	239	289	338	49	17.06%
Metered Energy	155	1,115	3,281	4,396	76	86	218	249	294	336	42	14.24%
Protective Lighting	0	634	1,798	2,432	104	109	215	229	320	338	18	5.72%
Lighting Total	**155**	**3,346**	**9,642**	**12,988**	**424**	**483**	**955**	**1,093**	**1,379**	**1,576**	**197**	**14.29%**
Total Retail	**80,330**	**705,233**	**1,237,309**	**1,942,542**	**56,166**	**63,183**	**90,217**	**101,673**	**146,384**	**164,856**	**18,472**	**12.62%**
Other Rev Increase					0	37	0	74	0	111	111	
Total Revenue	**80,330**	**705,233**	**1,237,309**	**1,942,542**	**56,166**	**63,220**	**90,217**	**101,747**	**146,384**	**164,967**	**18,583**	**12.69%**

REVENUE BY RATE CLASS

	Summer		Winter		Annual		Increase	
	Present	Proposed	Present	Proposed	Present	Proposed	Amount	Percent
Total Revenues ($1,000's)								
Residential Regular	21,969	24,937	33,446	38,518	55,415	63,455	8,040	14.51%
Res Space Heating	883	1,038	2,206	2,427	3,090	3,464	375	12.13%
Total Residential	22,852	25,975	35,653	40,944	58,505	66,919	8,414	14.38%
Small Comm. & Ind.	24,601	27,556	40,794	45,523	65,395	73,079	7,684	11.75%
Large Comm. & Ind.	8,393	9,278	13,030	14,339	21,423	23,618	2,195	10.25%
Total Comm. & Ind.	32,994	36,834	53,824	59,862	86,817	96,696	9,879	11.38%
Street Lighting	319	373	740	865	1,059	1,238	179	16.87%
Public Authorities	1	1	2	2	2	3	0	9.62%
Total Retail	56,166	63,183	90,217	101,673	146,384	164,856	18,472	12.62%
Other Revenues Incr.	0	37	0	74	0	111	111	
Retail + Increases	56,166	63,220	90,217	101,747	146,384	164,967	18,583	12.69%
Base Revenues ($1,000's)								
Residential Regular	15,459	18,367	22,808	27,781	38,267	46,147	7,880	20.59%
Res Space Heating	622	774	1,420	1,633	2,043	2,407	365	17.86%
Total Residential	16,081	19,140	24,228	29,414	40,309	48,554	8,245	20.45%
Small Comm. & Ind.	15,291	18,198	23,797	28,444	39,088	46,642	7,554	19.33%
Large Comm. & Ind.	4,509	5,476	6,512	7,987	11,021	13,463	2,442	22.16%
Total Comm. & Ind.	19,801	23,674	30,308	36,432	50,109	60,106	9,997	19.95%
Street Lighting	242	310	517	682	759	993	234	30.77%
Public Authorities	1	1	2	2	2	3	0	9.62%
Total Retail	36,125	43,126	55,055	66,530	91,180	109,655	18,476	20.26%
Other Revenues Incr.	0	37	0	74	0	111	111	
Retail + Increases*	36,125	43,163	55,055	66,604	91,180	109,766	18,587	20.38%
Fuel Revenues ($1,000's)								
Base	7,701	0	13,511	0	21,213	0	-21,213	
Adj.	12,340	20,057	21,651	35,143	33,991	55,200	21,209	
Total	20,042	20,057	35,162	35,143	55,204	55,200	-4	

*The $18,587 in the Increase / Amount column is $4,000 higher than the actual retail revenue increase recovered through the proposed rates and is the result of rounding with respect to fuel costs.

COMPARISON OF PRESENT & PROPOSED RATES

Fuel Cost - Retail	Present			Proposed		
	Summer	Winter	Annual	Summer	Winter	Annual
Retail	1.969 ¢	1.625 ¢	1.750 ¢	3.061 ¢	2.717 ¢	2.842 ¢
Residential	1.969 ¢	1.625 ¢	1.750 ¢	3.089 ¢	2.743 ¢	2.869 ¢
C&I - Non-Demand	1.969 ¢	1.625 ¢	1.750 ¢	3.162 ¢	2.807 ¢	2.936 ¢
C&I-Dmd - Non-TOD	1.969 ¢	1.625 ¢	1.750 ¢	3.094 ¢	2.746 ¢	2.872 ¢
C&I-Dmd -TOD On-Peak	1.969 ¢	1.625 ¢	1.750 ¢	4.027 ¢	3.575 ¢	3.739 ¢
C&I-Dmd -TOD Off-Peak	1.969 ¢	1.625 ¢	1.750 ¢	2.299 ¢	2.041 ¢	2.134 ¢
Lighting	1.969 ¢	1.625 ¢	1.750 ¢	2.501 ¢	2.220 ¢	2.322 ¢

		Present	Proposed	Present	Proposed
Residential (E01, E03)		Base Rates		Rates + Fuel	
Customer / Mo.	Overhead	$6.55	$7.50	$6.55	$7.50
	Underground	$8.55	$9.50	$8.55	$9.50
	Overhead - Electric Sp Ht	$6.55	$10.50	$6.55	$10.50
	Underground - Electric Sp Ht	$8.55	$12.50	$8.55	$12.50
Energy /kWh	Summer	7.250 ¢	7.434 ¢	9.219 ¢	10.523 ¢
	Winter 0-1000 KWH	6.260 ¢	6.234 ¢	7.885 ¢	8.977 ¢
	Winter Over 1000 KWH	5.750 ¢	6.234 ¢	7.375 ¢	8.977 ¢
	Win Sp Heat 0-1000 KWH	6.260 ¢	5.034 ¢	7.885 ¢	7.777 ¢
	Win Sp Heat Over 1000 KWH	4.280 ¢	5.034 ¢	5.905 ¢	7.777 ¢
Residential Time of Day (E02, E04)		Base Rates		Rates + Fuel	
Customer / Mo.	Overhead	$8.55	$9.50	$8.55	$9.50
	Underground	$10.55	$11.50	$10.55	$11.50
	Overhead - Electric Sp Ht	$8.55	$12.50	$8.55	$12.50
	Underground - Electric Sp Ht	$10.55	$14.50	$10.55	$14.50
Energy / kWh	On-Peak Summer	13.680 ¢	16.526 ¢	15.649 ¢	19.615 ¢
	On-Peak Winter	10.910 ¢	13.318 ¢	12.535 ¢	16.061 ¢
	On-Peak Winter -Elec. Sp Ht	9.020 ¢	10.603 ¢	10.645 ¢	13.346 ¢
	Off-Peak Summer	3.280 ¢	2.000 ¢	5.249 ¢	5.089 ¢
	Off-Peak Winter	3.280 ¢	2.000 ¢	4.905 ¢	4.743 ¢
Residential Heat Pump (E06)		Base Rates		Rates + Fuel	
Customer / Mo.		$2.50	$3.00	$2.50	$3.00
Energy / kWh	Summer	6.160 ¢	5.889 ¢	8.129 ¢	8.978 ¢
	Winter	3.910 ¢	3.934 ¢	5.535 ¢	6.677 ¢
Energy-Controlled Non-Demand (E10)		Base Rates		Rates + Fuel	
Customer / Mo.		$2.50	$3.00	$2.50	$3.00
Energy / kWh	Standard Resid.	3.530 ¢	3.400 ¢	5.280 ¢	6.269 ¢
	Standard Comm.	3.530 ¢	3.400 ¢	5.280 ¢	6.336 ¢
	Optional Resid. - Summer	7.250 ¢	7.434 ¢	9.219 ¢	10.523 ¢
	Optional Comm.- Summer	6.830 ¢	6.890 ¢	8.799 ¢	10.052 ¢

COMPARISON OF PRESENT & PROPOSED RATES

			Present	Proposed	Present	Proposed
Limited Off-Peak (E11)			Base Rates		Rates + Fuel	
Customer / Mo.	Residential		$2.70	$3.00	$2.70	$3.00
	Commercial	Sec - 1 Phase	$2.70	$3.00	$2.70	$3.00
	Commercial	Sec - 3 Phase	$4.05	$5.00	$4.05	$5.00
	Commercial	Primary	$24.00	$25.00	$24.00	$25.00
Energy / kWh	Residential	On-Peak	20.000 ¢	20.000 ¢	21.750 ¢	22.869 ¢
	Commercial	On-Peak	20.000 ¢	20.000 ¢	21.750 ¢	22.936 ¢
	Residential	Secondary	2.700 ¢	1.800 ¢	4.450 ¢	4.669 ¢
	Commercial	Secondary	2.700 ¢	1.800 ¢	4.450 ¢	4.736 ¢
Small General (E13)			Base Rates		Rates + Fuel	
Customer / Mo.			$7.25	$8.20	$7.25	$8.20
Energy /kWh	Summer		6.830 ¢	6.890 ¢	8.799 ¢	10.052 ¢
	Winter		5.830 ¢	5.689 ¢	7.455 ¢	8.496 ¢
Small General TOD (E14, E18)			Base Rates		Rates + Fuel	
Customer / Mo.			$9.25	$10.20	$9.25	$10.20
Energy / kWh	On-Peak Summer		10.660 ¢	12.753 ¢	12.629 ¢	15.915 ¢
	On-Peak Winter		8.680 ¢	10.155 ¢	10.305 ¢	12.962 ¢
	Off-Peak Summer		2.920 ¢	1.850 ¢	4.889 ¢	5.012 ¢
	Off-Peak Winter		2.920 ¢	1.850 ¢	4.545 ¢	4.657 ¢
	Constant Use - Summer		5.630 ¢	5.666 ¢	7.599 ¢	8.828 ¢
	Constant Use - Winter		4.940 ¢	4.757 ¢	6.565 ¢	7.564 ¢
Demand-Metered Voltage Discounts			Base Rates		Rates + Fuel	
Voltage Discount / kWh	Primary		0.060 ¢	0.090 ¢	0.060 ¢	0.090 ¢
	Trans. Transf.		0.090 ¢	0.140 ¢	0.090 ¢	0.140 ¢
	Transmision		0.120 ¢	0.200 ¢	0.120 ¢	0.200 ¢
Voltage Discount / kW	Primary		$0.80	$0.80	$0.80	$0.80
	Trans. Transf.		$1.50	$1.50	$1.50	$1.50
	Transmision		$2.05	$2.00	$2.05	$2.00
General (E15)			Base Rates		Rates + Fuel	
Customer / Mo.			$15.25	$18.00	$15.25	$18.00
Demand / kW	Summer		$9.35	$10.42	$9.35	$10.42
	Winter		$6.74	$7.42	$6.74	$7.42
Energy / kWh			3.090 ¢	2.540 ¢	4.840 ¢	5.412 ¢
Energy Credit / kWh			-0.550 ¢	-0.650 ¢	-0.550 ¢	-0.650 ¢

COMPARISON OF PRESENT & PROPOSED RATES

		Present	Proposed	Present	Proposed
General Time of Day (E16)		Base Rates		Rates + Fuel	
Customer / Mo.		$18.25	$21.00	$18.25	$21.00
On-Peak Demand / kW	Summer	$9.35	$10.42	$9.35	$10.42
	Winter	$6.74	$7.42	$6.74	$7.42
Off-Peak Demand / kW		$2.05	$2.00	$2.05	$2.00
Energy / kWh	On-Peak	3.560 ¢	3.230 ¢	5.310 ¢	6.969 ¢
	Off-Peak	2.670 ¢	2.019 ¢	4.420 ¢	4.153 ¢
Energy Credit / kWh		-0.550 ¢	-0.650 ¢	-0.550 ¢	-0.650 ¢

		Present	Proposed	Present	Proposed
Peak-Controlled (E20)		Base Rates		Rates + Fuel	
Customer / Mo.		$40.25	$45.00	$40.25	$45.00
Firm Demand / kW	Summer	$9.35	$10.42	$9.35	$10.42
	Winter	$6.74	$7.42	$6.74	$7.42
Control Demand / kW	Option A	$4.49	$5.30	$4.49	$5.30
	Option B - Summer (Closed)	$6.10	n/a	$6.10	n/a
	Option B - Winter (Closed)	$3.99	n/a	$3.99	n/a
Energy / kWh		3.090 ¢	2.540 ¢	4.840 ¢	5.412 ¢
Energy Credit / kWh		-0.550 ¢	-0.650 ¢	-0.550 ¢	-0.650 ¢

		Present	Proposed	Present	Proposed
Peak-Controlled TOD (E21)		Base Rates		Rates + Fuel	
Customer / Mo.		$43.25	$45.00	$43.25	$45.00
On-Peak Demand / kW	Summer	$9.35	$10.42	$9.35	$10.42
	Winter	$6.74	$7.42	$6.74	$7.42
Control Demand / kW	Option A	$4.49	$5.30	$4.49	$5.30
	Option B - Summer (Closed)	$6.10	n/a	$6.10	n/a
	Option B - Winter (Closed)	$3.99	n/a	$3.99	n/a
Off-Peak Demand / kW		$2.05	$2.00	$2.05	$2.00
Energy / kWh	On-Peak	3.560 ¢	3.230 ¢	5.310 ¢	6.969 ¢
	Off-Peak	2.670 ¢	2.019 ¢	4.420 ¢	4.153 ¢
Energy Credit / kWh		-0.5500 ¢	-0.6500 ¢	-0.5500 ¢	-0.6500 ¢

		Present	Proposed	Present	Proposed
Energy-Controlled Service (E22)		Base Rates		Rates + Fuel	
Customer / Mo.		$43.25	$45.00	$43.25	$45.00
On-Peak Demand / kW	Summer	$9.35	$10.42	$9.35	$10.42
	Winter	$6.74	$7.42	$6.74	$7.42
Control Demand / kW		$4.28	$5.09	$4.28	$5.09
Off-Peak Demand / kW		$2.05	$2.00	$2.05	$2.00
Energy / kWh	Firm On-Peak	3.560 ¢	3.230 ¢	5.310 ¢	6.969 ¢
	Firm Off-Peak	2.670 ¢	2.019 ¢	4.420 ¢	4.153 ¢
	Controllable On-Peak	3.100 ¢	2.830 ¢	4.850 ¢	6.569 ¢
	Controllable Off-Peak	2.460 ¢	1.839 ¢	4.210 ¢	3.973 ¢
	Control Period Energy	10.000 ¢	8.000 ¢	11.750 ¢	11.739 ¢
Energy Credit / kWh		-0.550 ¢	-0.650 ¢	-0.550 ¢	-0.650 ¢

COMPARISON OF PRESENT & PROPOSED RATES

		Present	Proposed	Present	Proposed
Automatic Protective Lighting (E12)		Base Rates		Rates + Fuel	
Area	100 W HPSodium	$6.50	$6.70	$7.21	$7.64
	175 W Mercury	$6.50	$6.36	$7.73	$7.99
	250 W HPSodium	$12.25	$12.49	$14.11	$14.96
	400 W Mercury	$12.25	$11.87	$15.04	$15.57
Directional	250 W HPSodium	$13.70	$14.02	$15.56	$16.49
	400 W Mercury	$13.70	$13.78	$16.49	$17.48
	400 W HPSodium	$18.00	$18.30	$20.92	$22.18
	1000 W Mercury	$31.50			

		Present	Proposed	Present	Proposed
St. Lighting System (E30)		Base Rates		Rates + Fuel	
Overhead	100 W HPSodium	$9.90	$11.55	$10.61	$12.49
	150 W HPSodium	$11.45	$13.22	$12.49	$14.60
	250 W HPSodium	$14.80	$17.00	$16.66	$19.47
	400 W HPSodium	$18.30	$20.89	$21.22	$24.77
Underground	100 W HPSodium	$15.60	$18.43	$16.31	$19.37
	150 W HPSodium	$17.30	$20.25	$18.34	$21.63
	250 W HPSodium	$20.95	$24.33	$22.81	$26.80
Decorative UG	100 W HPSodium	$18.85	$23.50	$19.56	$24.44
	150 W HPSodium	$19.95	$24.72	$20.99	$26.10
	250 W HPSodium	$26.10	$31.18	$27.96	$33.65

		Present	Proposed	Present	Proposed
St. Lighting Energy (E31)		Base Rates		Rates + Fuel	
Group 1	70 W HPSodium	$3.40	$3.62	$3.89	$4.27
	100 W HPSodium	$3.80	$4.11	$4.51	$5.05
	150 W HPSodium	$4.60	$4.98	$5.64	$6.36
	250 W HPSodium	$6.60	$7.19	$8.46	$9.66
	400 W HPSodium	$9.30	$10.12	$12.22	$14.00
	1000 W HPSodium	$20.00	$21.55	$26.86	$30.65
	175 W Mercury	$4.25	$4.87	$5.48	$6.50
	400 W Mercury	$8.20	$9.17	$10.99	$12.87
Group 4	70 W HPSodium	$1.45	$1.61	$1.94	$2.26
	100 W HPSodium	$1.80	$2.06	$2.51	$3.00
	150 W HPSodium	$2.80	$3.09	$3.84	$4.47
	250 W HPSodium	$4.80	$5.30	$6.66	$7.77
	400 W HPSodium	$7.40	$8.16	$10.32	$12.04
	175 W Mercury	$3.25	$3.60	$4.48	$5.23
Group 4 Metered	Energy Charge per kWh	4.880 ¢	5.220 ¢	6.630 ¢	7.542 ¢

	Present	Proposed	Present	Proposed
St. Lighting Energy - Metered (E34)	Base Rates		Rates + Fuel	
Customer / Mo.	$7.25	$8.20	$7.25	$8.20
Energy Charge per kWh	4.630 ¢	4.970 ¢	6.380 ¢	7.292 ¢

Docket No. EL09-___
Exhibit No. ______(SVH-1), Schedule 4

COMPARISON OF PRESENT & PROPOSED RATES

		Present	Proposed
Fire & Civil Defense Siren (E40)			
HP Capacity / Mo.		$0.52	$0.57
Min Charge / Mo.		$2.55	$2.81

		Present	Proposed
Standby Service Rider			
Customer / Mo.	Unscheduled Maintenance	$25.00	$25.00
	Scheduled Maintenance	$25.00	$25.00
Demand / Contract kW	Unscheduled-Secondary	$2.85	$2.90
	Unscheduled-Primary	$2.05	$2.10
	Unscheduled-Trans. Transf.	$1.35	$1.40
	Unscheduled-Transmission	$0.80	$0.90
	Scheduled-Secondary	$2.75	$2.80
	Scheduled-Primary	$1.95	$2.00
	Scheduled-Trans. Transf.	$1.25	$1.30
	Scheduled-Transmission	$0.70	$0.80

COMPARISON OF BILLS AT PRESENT & PROPOSED RATES

RESIDENTIAL SERVICE (OVERHEAD) - E01

	Energy in kWh	Monthly Bill Present	Monthly Bill Proposed	Increase Amount	Increase Percent
	250	$26.26	$29.94	$3.68	14.01%
	300	$30.21	$34.43	$4.22	13.99%
	400	$38.09	$43.41	$5.32	13.96%
	500	$45.98	$52.38	$6.41	13.94%
	600	$53.86	$61.36	$7.50	13.92%
WINTER	675	$59.77	$68.09	$8.32	13.92%
	750	$65.69	$74.82	$9.14	13.91%
	1000	$85.40	$97.27	$11.87	13.89%
	1500	$122.28	$142.15	$19.87	16.25%
	2000	$159.15	$187.03	$27.88	17.52%
	3000	$232.90	$276.80	$43.90	18.85%
	4000	$306.65	$366.57	$59.91	19.54%
	5000	$380.41	$456.33	$75.93	19.96%
	250	$29.60	$33.81	$4.21	14.23%
	300	$34.21	$39.07	$4.86	14.22%
	400	$43.42	$49.59	$6.17	14.21%
	500	$52.64	$60.12	$7.47	14.20%
	600	$61.86	$70.64	$8.78	14.19%
SUMMER	675	$68.78	$78.53	$9.76	14.19%
	750	$75.69	$86.43	$10.74	14.18%
	1000	$98.74	$112.73	$14.00	14.18%
	1500	$144.83	$165.35	$20.52	14.17%
	2000	$190.92	$217.97	$27.05	14.17%
	3000	$283.11	$323.20	$40.09	14.16%
	4000	$375.30	$428.44	$53.14	14.16%
	5000	$467.49	$533.67	$66.19	14.16%
	250	$27.37	$31.23	$3.86	14.09%
	300	$31.54	$35.98	$4.44	14.07%
	400	$39.87	$45.47	$5.60	14.05%
	500	$48.20	$54.96	$6.76	14.03%
	600	$56.53	$64.45	$7.93	14.02%
AVERAGE	675	$62.78	$71.57	$8.80	14.01%
MONTHLY	750	$69.02	$78.69	$9.67	14.01%
	1000	$89.85	$102.42	$12.58	14.00%
	1500	$129.79	$149.88	$20.09	15.48%
	2000	$169.74	$197.35	$27.60	16.26%
	3000	$249.64	$292.27	$42.63	17.08%
	4000	$329.54	$387.19	$57.65	17.50%
	5000	$409.43	$482.11	$72.68	17.75%

COMPARISON OF BILLS AT PRESENT & PROPOSED RATES

RESIDENTIAL SERVICE - SPACE HEATING (OVERHEAD) - E01

	Energy	Monthly Bill		Increase	
	in kWh	Present	Proposed	Amount	Percent
	250	$26.26	$29.94	$3.68	14.01%
	300	$30.21	$33.83	$3.62	12.00%
	400	$38.09	$41.61	$3.52	9.23%
	500	$45.98	$49.38	$3.41	7.41%
	600	$53.86	$57.16	$3.30	6.13%
WINTER	675	$59.77	$62.99	$3.22	5.38%
	750	$65.69	$68.82	$3.14	4.77%
	1000	$85.40	$88.27	$2.87	3.36%
	1500	$114.93	$127.15	$12.22	10.64%
	2000	$144.45	$166.03	$21.58	14.94%
	3000	$203.50	$243.80	$40.30	19.80%
	4000	$262.55	$321.57	$59.01	22.48%
	5000	$321.61	$399.33	$77.73	24.17%
	250	$29.60	$36.81	$7.21	24.37%
	300	$34.21	$42.07	$7.86	22.99%
	400	$43.42	$52.59	$9.17	21.11%
	500	$52.64	$63.12	$10.47	19.90%
	600	$61.86	$73.64	$11.78	19.04%
SUMMER	675	$68.78	$81.53	$12.76	18.55%
	750	$75.69	$89.43	$13.74	18.15%
	1000	$98.74	$115.73	$17.00	17.22%
	1500	$144.83	$168.35	$23.52	16.24%
	2000	$190.92	$220.97	$30.05	15.74%
	3000	$283.11	$326.20	$43.09	15.22%
	4000	$375.30	$431.44	$56.14	14.96%
	5000	$467.49	$536.67	$69.19	14.80%
	250	$27.37	$32.23	$4.86	17.74%
	300	$31.54	$36.58	$5.04	15.97%
	400	$39.87	$45.27	$5.40	13.55%
	500	$48.20	$53.96	$5.76	11.96%
	600	$56.53	$62.65	$6.13	10.84%
AVERAGE	675	$62.78	$69.17	$6.40	10.19%
MONTHLY	750	$69.02	$75.69	$6.67	9.66%
	1000	$89.85	$97.42	$7.58	8.43%
	1500	$124.89	$140.88	$15.99	12.80%
	2000	$159.94	$184.35	$24.40	15.26%
	3000	$230.04	$271.27	$41.23	17.92%
	4000	$300.14	$358.19	$58.05	19.34%
	5000	$370.23	$445.11	$74.88	20.23%

COMPARISON OF BILLS AT PRESENT & PROPOSED RATES

RESIDENTIAL SERVICE (UNDERGROUND) - E03

	Energy	Monthly Bill		Increase	
	in kWh	Present	Proposed	Amount	Percent
	250	$28.26	$31.94	$3.68	13.02%
	300	$32.21	$36.43	$4.22	13.12%
	400	$40.09	$45.41	$5.32	13.26%
	500	$47.98	$54.38	$6.41	13.36%
	600	$55.86	$63.36	$7.50	13.42%
WINTER	675	$61.77	$70.09	$8.32	13.46%
	750	$67.69	$76.82	$9.14	13.50%
	1000	$87.40	$99.27	$11.87	13.58%
	1500	$124.28	$144.15	$19.87	15.99%
	2000	$161.15	$189.03	$27.88	17.30%
	3000	$234.90	$278.80	$43.90	18.69%
	4000	$308.65	$368.57	$59.91	19.41%
	5000	$382.41	$458.33	$75.93	19.86%
	250	$31.60	$35.81	$4.21	13.33%
	300	$36.21	$41.07	$4.86	13.44%
	400	$45.42	$51.59	$6.17	13.58%
	500	$54.64	$62.12	$7.47	13.68%
	600	$63.86	$72.64	$8.78	13.75%
SUMMER	675	$70.78	$80.53	$9.76	13.79%
	750	$77.69	$88.43	$10.74	13.82%
	1000	$100.74	$114.73	$14.00	13.90%
	1500	$146.83	$167.35	$20.52	13.98%
	2000	$192.92	$219.97	$27.05	14.02%
	3000	$285.11	$325.20	$40.09	14.06%
	4000	$377.30	$430.44	$53.14	14.08%
	5000	$469.49	$535.67	$66.19	14.10%
	250	$29.37	$33.23	$3.86	13.13%
	300	$33.54	$37.98	$4.44	13.23%
	400	$41.87	$47.47	$5.60	13.38%
	500	$50.20	$56.96	$6.76	13.47%
	600	$58.53	$66.45	$7.93	13.54%
AVERAGE	675	$64.78	$73.57	$8.80	13.58%
MONTHLY	750	$71.02	$80.69	$9.67	13.61%
	1000	$91.85	$104.42	$12.58	13.69%
	1500	$131.79	$151.88	$20.09	15.24%
	2000	$171.74	$199.35	$27.60	16.07%
	3000	$251.64	$294.27	$42.63	16.94%
	4000	$331.54	$389.19	$57.65	17.39%
	5000	$411.43	$484.11	$72.68	17.67%

COMPARISON OF BILLS AT PRESENT & PROPOSED RATES

RESIDENTIAL SERVICE - SPACE HEATING (UNDERGROUND) - E03

	Energy in kWh	Monthly Bill Present	Monthly Bill Proposed	Increase Amount	Increase Percent
	250	$28.26	$31.94	$3.68	13.02%
	300	$32.21	$35.83	$3.62	11.25%
	400	$40.09	$43.61	$3.52	8.77%
	500	$47.98	$51.38	$3.41	7.10%
	600	$55.86	$59.16	$3.30	5.91%
WINTER	675	$61.77	$64.99	$3.22	5.21%
	750	$67.69	$70.82	$3.14	4.63%
	1000	$87.40	$90.27	$2.87	3.28%
	1500	$116.93	$129.15	$12.22	10.45%
	2000	$146.45	$168.03	$21.58	14.74%
	3000	$205.50	$245.80	$40.30	19.61%
	4000	$264.55	$323.57	$59.01	22.31%
	5000	$323.61	$401.33	$77.73	24.02%
	250	$31.60	$38.81	$7.21	22.82%
	300	$36.21	$44.07	$7.86	21.72%
	400	$45.42	$54.59	$9.17	20.19%
	500	$54.64	$65.12	$10.47	19.17%
	600	$63.86	$75.64	$11.78	18.44%
SUMMER	675	$70.78	$83.53	$12.76	18.02%
	750	$77.69	$91.43	$13.74	17.68%
	1000	$100.74	$117.73	$17.00	16.87%
	1500	$146.83	$170.35	$23.52	16.02%
	2000	$192.92	$222.97	$30.05	15.57%
	3000	$285.11	$328.20	$43.09	15.11%
	4000	$377.30	$433.44	$56.14	14.88%
	5000	$469.49	$538.67	$69.19	14.74%
	250	$29.37	$34.23	$4.86	16.53%
	300	$33.54	$38.58	$5.04	15.02%
	400	$41.87	$47.27	$5.40	12.90%
	500	$50.20	$55.96	$5.76	11.48%
	600	$58.53	$64.65	$6.13	10.47%
AVERAGE	675	$64.78	$71.17	$6.40	9.88%
MONTHLY	750	$71.02	$77.69	$6.67	9.39%
	1000	$91.85	$99.42	$7.58	8.25%
	1500	$126.89	$142.88	$15.99	12.60%
	2000	$161.94	$186.35	$24.40	15.07%
	3000	$232.04	$273.27	$41.23	17.77%
	4000	$302.14	$360.19	$58.05	19.21%
	5000	$372.23	$447.11	$74.88	20.12%

COMPARISON OF BILLS AT PRESENT & PROPOSED RATES

SMALL GENERAL SERVICE - E13

	Energy in kWh	Monthly Bill Present	Monthly Bill Proposed	Increase Amount	Increase Percent
	250	$25.89	$29.44	$3.55	13.72%
	300	$29.62	$33.69	$4.07	13.76%
	400	$37.07	$42.19	$5.11	13.80%
	500	$44.53	$50.68	$6.16	13.83%
WINTER	600	$51.98	$59.18	$7.20	13.85%
	750	$63.16	$71.92	$8.76	13.87%
	1000	$81.80	$93.16	$11.36	13.89%
	1500	$119.08	$135.64	$16.57	13.91%
	2000	$156.35	$178.13	$21.77	13.93%
	3000	$230.90	$263.09	$32.19	13.94%
	4000	$305.45	$348.05	$42.60	13.95%
	5000	$380.01	$433.02	$53.01	13.95%
	250	$29.25	$33.33	$4.08	13.96%
	300	$33.65	$38.36	$4.71	14.00%
	400	$42.44	$48.41	$5.96	14.05%
	500	$51.24	$58.46	$7.22	14.09%
SUMMER	600	$60.04	$68.51	$8.47	14.11%
	750	$73.24	$83.59	$10.35	14.13%
	1000	$95.24	$108.72	$13.49	14.16%
	1500	$139.23	$158.98	$19.75	14.19%
	2000	$183.22	$209.25	$26.02	14.20%
	3000	$271.21	$309.77	$38.56	14.22%
	4000	$359.20	$410.29	$51.09	14.22%
	5000	$447.19	$510.82	$63.63	14.23%
	250	$27.01	$30.74	$3.73	13.81%
	300	$30.96	$35.24	$4.29	13.84%
	400	$38.86	$44.26	$5.40	13.89%
	500	$46.76	$53.27	$6.51	13.92%
AVERAGE	600	$54.67	$62.29	$7.62	13.94%
MONTHLY	750	$66.52	$75.81	$9.29	13.97%
	1000	$86.28	$98.35	$12.07	13.99%
	1500	$125.79	$143.42	$17.63	14.02%
	2000	$165.31	$188.50	$23.19	14.03%
	3000	$244.34	$278.65	$34.31	14.04%
	4000	$323.37	$368.80	$45.43	14.05%
	5000	$402.40	$458.95	$56.55	14.05%

COMPARISON OF BILLS AT PRESENT & PROPOSED RATES

GENERAL SERVICE - E15 (Secondary Voltage)

Demand	Energy		Monthly Bill		Increase	
in kW	in kWh	Hours	Present	Proposed	Amount	Percent
15	3,000	200	$274.59	$306.67	$32.08	11.68%
15	6,000	400	$416.49	$465.15	$48.66	11.68%
15	9,000	600	$545.18	$608.02	$62.84	11.53%
25	5,000	200	$447.49	$499.12	$51.63	11.54%
25	10,000	400	$683.98	$763.25	$79.27	11.59%
25	15,000	600	$898.47	$1,001.37	$102.90	11.45%
50	10,000	200	$879.73	$980.25	$100.52	11.43%
50	20,000	400	$1,352.71	$1,508.50	$155.79	11.52%
50	30,000	600	$1,781.69	$1,984.75	$203.06	11.40%
75	15,000	200	$1,311.97	$1,461.37	$149.40	11.39%
75	30,000	400	$2,021.44	$2,253.75	$232.31	11.49%
75	45,000	600	$2,664.91	$2,968.12	$303.21	11.38%
100	20,000	200	$1,744.21	$1,942.50	$198.29	11.37%
100	40,000	400	$2,690.17	$2,999.00	$308.83	11.48%
100	60,000	600	$3,548.13	$3,951.49	$403.36	11.37%
200	40,000	200	$3,473.17	$3,867.00	$393.83	11.34%
200	80,000	400	$5,365.09	$5,979.99	$614.90	11.46%
200	120,000	600	$7,081.01	$7,884.99	$803.98	11.35%
300	60,000	200	$5,202.13	$5,791.49	$589.36	11.33%
300	120,000	400	$8,040.01	$8,960.99	$920.98	11.45%
300	180,000	600	$10,613.89	$11,818.48	$1,204.59	11.35%
500	100,000	200	$8,660.05	$9,640.49	$980.44	11.32%
500	200,000	400	$13,389.85	$14,922.98	$1,533.13	11.45%
500	300,000	600	$17,679.65	$19,685.47	$2,005.82	11.35%
1,000	200,000	200	$17,304.85	$19,262.98	$1,958.13	11.32%
1,000	400,000	400	$26,764.45	$29,827.97	$3,063.52	11.45%
1,000	600,000	600	$35,344.05	$39,352.95	$4,008.90	11.34%
3,000	600,000	200	$51,884.05	$57,752.95	$5,868.90	11.31%
3,000	1,200,000	400	$80,262.85	$89,447.90	$9,185.05	11.44%
3,000	1,800,000	600	$106,001.65	$118,022.85	$12,021.20	11.34%
5,000	1,000,000	200	$86,463.25	$96,242.91	$9,779.66	11.31%
5,000	2,000,000	400	$133,761.25	$149,067.83	$15,306.58	11.44%
5,000	3,000,000	600	$176,659.25	$196,692.74	$20,033.49	11.34%

COMPARISON OF BILLS AT PRESENT & PROPOSED RATES

GENERAL SERVICE - E15 (Primary Voltage)

Demand in kW	Energy in kWh	Hours	Monthly Bill Present	Monthly Bill Proposed	Increase Amount	Increase Percent
15	3,000	200	$260.79	$291.97	$31.18	11.96%
15	6,000	400	$400.89	$447.75	$46.86	11.69%
15	9,000	600	$527.78	$587.92	$60.14	11.40%
25	5,000	200	$424.49	$474.62	$50.13	11.81%
25	10,000	400	$657.98	$734.25	$76.27	11.59%
25	15,000	600	$869.47	$967.87	$98.40	11.32%
50	10,000	200	$833.73	$931.25	$97.52	11.70%
50	20,000	400	$1,300.71	$1,450.50	$149.79	11.52%
50	30,000	600	$1,723.69	$1,917.75	$194.06	11.26%
75	15,000	200	$1,242.97	$1,387.87	$144.90	11.66%
75	30,000	400	$1,943.44	$2,166.75	$223.31	11.49%
75	45,000	600	$2,577.91	$2,867.62	$289.71	11.24%
100	20,000	200	$1,652.21	$1,844.50	$192.29	11.64%
100	40,000	400	$2,586.17	$2,883.00	$296.83	11.48%
100	60,000	600	$3,432.13	$3,817.49	$385.36	11.23%
200	40,000	200	$3,289.17	$3,671.00	$381.83	11.61%
200	80,000	400	$5,157.09	$5,747.99	$590.90	11.46%
200	120,000	600	$6,849.01	$7,616.99	$767.98	11.21%
300	60,000	200	$4,926.13	$5,497.49	$571.36	11.60%
300	120,000	400	$7,728.01	$8,612.99	$884.98	11.45%
300	180,000	600	$10,265.89	$11,416.48	$1,150.59	11.21%
500	100,000	200	$8,200.05	$9,150.49	$950.44	11.59%
500	200,000	400	$12,869.85	$14,342.98	$1,473.13	11.45%
500	300,000	600	$17,099.65	$19,015.47	$1,915.82	11.20%
1,000	200,000	200	$16,384.85	$18,282.98	$1,898.13	11.58%
1,000	400,000	400	$25,724.45	$28,667.97	$2,943.52	11.44%
1,000	600,000	600	$34,184.05	$38,012.95	$3,828.90	11.20%
3,000	600,000	200	$49,124.05	$54,812.95	$5,688.90	11.58%
3,000	1,200,000	400	$77,142.85	$85,967.90	$8,825.05	11.44%
3,000	1,800,000	600	$102,521.65	$114,002.85	$11,481.20	11.20%
5,000	1,000,000	200	$81,863.25	$91,342.91	$9,479.66	11.58%
5,000	2,000,000	400	$128,561.25	$143,267.83	$14,706.58	11.44%
5,000	3,000,000	600	$170,859.25	$189,992.74	$19,133.49	11.20%

COMPARISON OF BILLS AT PRESENT & PROPOSED RATES

GENERAL TOD SERVICE -E16 (Secondary Voltage**)** Ave On-Peak 43.04%

Demand in kW	Energy in kWh	Hours	Monthly Bill Present	Monthly Bill Proposed	Increase Amount	Increase Percent
15	3,000	200	$276.49	$308.26	$31.77	11.49%
15	6,000	400	$417.27	$465.31	$48.04	11.51%
15	9,000	600	$544.86	$606.77	$61.91	11.36%
25	5,000	200	$448.64	$499.76	$51.12	11.39%
25	10,000	400	$683.29	$761.52	$78.24	11.45%
25	15,000	600	$895.93	$997.28	$101.35	11.31%
50	10,000	200	$879.04	$978.52	$99.49	11.32%
50	20,000	400	$1,348.32	$1,502.04	$153.72	11.40%
50	30,000	600	$1,773.61	$1,973.57	$199.96	11.27%
75	15,000	200	$1,309.43	$1,457.28	$147.85	11.29%
75	30,000	400	$2,013.36	$2,242.57	$229.21	11.38%
75	45,000	600	$2,651.29	$2,949.85	$298.56	11.26%
100	20,000	200	$1,739.82	$1,936.04	$196.22	11.28%
100	40,000	400	$2,678.39	$2,983.09	$304.70	11.38%
100	60,000	600	$3,528.96	$3,926.13	$397.17	11.25%
200	40,000	200	$3,461.39	$3,851.09	$389.70	11.26%
200	80,000	400	$5,338.53	$5,945.18	$606.64	11.36%
200	120,000	600	$7,039.68	$7,831.26	$791.59	11.24%
300	60,000	200	$5,182.96	$5,766.13	$583.17	11.25%
300	120,000	400	$7,998.68	$8,907.26	$908.59	11.36%
300	180,000	600	$10,550.39	$11,736.39	$1,186.00	11.24%
500	100,000	200	$8,626.11	$9,596.22	$970.11	11.25%
500	200,000	400	$13,318.96	$14,831.44	$1,512.48	11.36%
500	300,000	600	$17,571.82	$19,546.66	$1,974.84	11.24%
1,000	200,000	200	$17,233.96	$19,171.44	$1,937.48	11.24%
1,000	400,000	400	$26,619.67	$29,641.88	$3,022.20	11.35%
1,000	600,000	600	$35,125.39	$39,072.31	$3,946.93	11.24%
3,000	600,000	200	$51,665.39	$57,472.31	$5,806.93	11.24%
3,000	1,200,000	400	$79,822.52	$88,883.63	$9,061.11	11.35%
3,000	1,800,000	600	$105,339.66	$117,174.94	$11,835.29	11.24%
5,000	1,000,000	200	$86,096.81	$95,773.19	$9,676.38	11.24%
5,000	2,000,000	400	$133,025.37	$148,125.38	$15,100.01	11.35%
5,000	3,000,000	600	$175,553.93	$195,277.57	$19,723.64	11.24%

Northern States Power Company, a Minnesota corporation
Electric Utility - South Dakota
Test Year Ending December 31, 2008

Docket No. EL09-___
Exhibit No. ______(SVH-1), Schedule 6

FUEL COST RIDER - FUEL ADJUSTMENT FACTOR CALCULATION

		SERVICE CATEGORY						
		Residential	C&I Non-Dmd	C&I Demand			Outdoor Lighting	RETAIL
	STEP 1: CLASS RATIOS							
1.	Test-Year Marginal Energy Cost *	$41,883,288	$6,535,470	$75,535,530			$682,773	$124,637,061
2.	Test-Year MWh Energy (at Generator)	669,772	102,106	1,226,471			13,487	2,011,836
3.	Average Load-Weighted Marginal Energy Cost Per MWh (1)/(2)	$62.534	$64.007	$61.588			$50.623	$61.952
4.	**Class Ratio (Class Unit Cost / Retail Unit Cost)**	**1.0094**	**1.0332**	**0.9941**			**0.8171**	**1.0000**
	STEP 2: C&I DEMAND TOD RATIOS							
				Non-TOD	On-Peak	Off-Peak		
5.	Ratio of On- to Off-Peak TY Wtd Marginal Energy Costs				1.752			
6.	C&I Demand Class On/Off-Peak Percentage from 8760 loads				0.4304	0.5696		
7.	C&I Demand TOD On-Peak Ratio = 1 / (0.4304 + (0.5696 / 1.752)) **				**1.3236**			
8.	C&I Demand TOD Off-Peak Ratio = 1 / ((1.7520 x 0.4304) + 0.5696)) **					**0.7555**		
9.	C&I Non-TOD On-Peak Weighting			0.4600				
10.	C&I Non-TOD Off-Peak Weighting			0.5400				
11.	C&I Demand Non-TOD Ratio = (0.46000 x 1.3236) + (0.54000 x 0.7555)			**1.0168**				
	STEP 3: FUEL ADJUSTMENT FACTOR							
12.	FAF = Step 1, or for C&I-Demand, Step 1 x Step 2	**1.0094**	**1.0332**	**1.0108**	**1.3158**	**0.7510**	**0.8171**	

* E8760 Allocator = Sum of Hourly System Marginal Costs times Class Hourly Loads

** TOD Ratio Equations is derived from the following:

Weighted Average = (0.4304 x on-peak charge) + (0.5696 x off-peak charge), where 0.4304 and 0.5696 are C&I Demand class on-peak % and off-peak % respectively

KWH

100 kWh Block Sales	Jan	Feb		Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
MN Residential	117,347	105,515	96,653	99,313	89,252	91,759	112,997	109,135	106,820	99,306	82,148	109,014	1,219,260
MN Com & Ind	42,673	24,004	35,011	39,394	36,778	35,560	54,007	46,427	67,145	49,262	42,648	43,452	516,361
MN Total Blocks	160,020	129,518	131,664	138,708	126,030	127,319	167,004	155,562	173,965	148,568	124,796	152,466	1,735,621
SD Residential	0	0	0	78	156	234	312	390	467	545	623	701	3,506
SD Com & Ind	0	0	0	39	78	117	156	195	234	273	312	351	1,753
SD Total Blocks	0	0	0	117	234	351	467	584	701	818	935	1,052	5,259
Grand Total Blocks	160,020	129,518	131,664	138,825	126,264	127,670	167,472	156,147	174,666	149,386	125,731	153,517	1,740,880
YTD Wind kWh Sold	**16,002,033**	**28,953,861**	**42,120,265**	**56,002,721**	**68,629,129**	**81,396,123**	**98,143,294**	**113,757,959**	**131,224,564**	**146,163,135**	**158,736,277**	**174,088,013**	
Program Generation													
Invoiced Wind kWh Generated	17,620,466	13,331,195	16,071,077	17,610,469	17,566,143	11,149,572	9,333,570	8,437,974	13,158,652	16,595,502	17,971,315	15,242,079	174,088,013
REC kWh (1 REC = 1000 kWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Wind kWh Generated	17,620,466	13,331,195	16,071,077	17,610,469	17,566,143	11,149,572	9,333,570	8,437,974	13,158,652	16,595,502	17,971,315	15,242,079	174,088,013
YTD Wind kWh Generated	**17,620,466**	**30,951,662**	**47,022,738**	**64,633,208**	**82,199,350**	**93,348,922**	**102,682,492**	**111,120,466**	**124,279,118**	**140,874,620**	**158,845,935**	**174,088,013**	
Monthly kWh (Over)/Under	**1,618,433**	**379,367**	**2,904,673**	**3,728,014**	**4,939,734**	**-1,617,422**	**-7,413,601**	**-7,176,691**	**-4,307,953**	**1,656,931**	**5,398,173**	**-109,657**	
YTD kWh (Over)/Under	**1,618,433**	**1,997,800**	**4,902,473**	**8,630,487**	**13,570,221**	**11,952,799**	**4,539,199**	**-2,637,493**	**-6,945,446**	**-5,288,515**	**109,657**	**0**	
Monthly Generation Capacity Factor	26.7%	40.1%	36.7%	40.8%	34.9%	25.9%	21.0%	18.9%	30.5%	37.3%	41.7%	34.2%	32.3%
YTD Generation Capacity Factor	26.7%	33.8%	34.8%	36.3%	36.0%	34.3%	32.4%	30.6%	30.6%	31.3%	32.2%	32.4%	

Dollars

Program Sales Revenue $3.60	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
MN Residential	$422,378	$379,788	$347,891	$357,467	$321,253	$330,277	$406,720	$392,818	$384,485	$357,440	$295,682	$392,382	$4,388,581
MN Com & Ind	$153,596	$86,398	$126,018	$141,795	$132,378	$127,994	$194,392	$167,110	$241,680	$177,311	$153,508	$156,400	$1,858,580
MN Total Revenue	$575,974	$466,186	$473,909	$499,262	$453,631	$458,271	$601,112	$559,928	$626,166	$534,751	$449,190	$548,781	$6,247,160
SD Residential	$0	$0	$0	$280	$561	$841	$1,122	$1,402	$1,683	$1,963	$2,243	$2,524	$12,619
SD Com & Ind	$0	$0	$0	$140	$280	$421	$561	$701	$841	$982	$1,122	$1,262	$6,310
SD Total Revenue	$0	$0	$0	$421	$841	$1,262	$1,683	$2,103	$2,524	$2,945	$3,365	$3,786	$18,929
Grand Total Revenue	**$575,974**	**$466,186**	**$473,909**	**$499,682**	**$454,472**	**$459,533**	**$602,794**	**$562,031**	**$628,689**	**$537,696**	**$452,555**	**$552,567**	**$6,266,089**
Program Gen. Expense													
Wind Contracts Payments	$768,226	$581,220	$700,675	$767,790	$765,858	$486,105	$406,930	$367,883	$573,698	$723,539	$783,523	$664,532	$7,589,980
REC MWh Purchase, @ $3.00	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
System Fuel Costs per kWh *	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
REC-Related Fuel Costs *	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Windsource Energy Costs	$768,226	$581,220	$700,675	$767,790	$765,858	$486,105	$406,930	$367,883	$573,698	$723,539	$783,523	$664,532	$7,589,980
*Traditional "brown" generation costs made "green" by the application of RECs													
Admin. Labor	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$108,000
Marketing Expense	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$12,000
Admin.Other	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$24,000
Total Admin & Mktg	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	$144,000
Gen Capacity Credit @ -$0.00845	-$148,893	-$112,649	-$135,801	-$148,808	-$148,434	-$94,214	-$78,869	-$71,301	-$111,191	-$140,232	-$151,858	-$128,796	-$1,471,044
Total Expense	**$631,333**	**$480,572**	**$576,875**	**$630,982**	**$629,424**	**$403,891**	**$340,061**	**$308,582**	**$474,507**	**$595,307**	**$643,665**	**$547,737**	**$6,262,936**
Monthly Over/(Under) Recocery	**-$55,359**	**-$14,386**	**-$102,966**	**-$131,300**	**-$174,951**	**$55,642**	**$262,733**	**$253,449**	**$154,182**	**-$57,611**	**-$191,110**	**$4,831**	**$3,153**
Interest Calculation													
Beginning Balance	$0	-$55,435	-$69,978	-$173,278	-$305,216	-$481,251	-$426,821	-$164,904	$88,440	$243,065	$186,044	-$4,824	
Ending Bal (Begin+Over/Under)	-$55,359	-$69,822	-$172,943	-$304,578	-$480,167	-$425,610	-$164,088	$88,545	$242,623	$185,453	-$5,066	$7	
Average Balance	-$27,680	-$62,628	-$121,460	-$238,928	-$392,692	-$453,431	-$295,454	-$38,179	$165,531	$214,259	$90,489	-$2,408	
Prime Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
Days In Month	31	28	31	30	31	30	31	31	30	31	30	31	365
Monthly Interest	**-$76**	**-$156**	**-$335**	**-$638**	**-$1,084**	**-$1,211**	**-$816**	**-$105**	**$442**	**$591**	**$242**	**-$7**	**-$3,153**
Monthly Tracker Bal w/ Int	**-$55,435**	**-$14,542**	**-$103,301**	**-$131,938**	**-$176,035**	**$54,431**	**$261,917**	**$253,344**	**$154,624**	**-$57,020**	**-$190,868**	**$4,824**	**$0**
YTD Tracker Bal w/ Int	**-$55,435**	**-$69,978**	**-$173,278**	**-$305,216**	**-$481,251**	**-$426,821**	**-$164,904**	**$88,440**	**$243,065**	**$186,044**	**-$4,824**	**$0**	

Note: MISO currently declares each month to simply have a 20% capacity credit for wind resources
In contrast, actual weather patterns show that summer months consistently produce lower wind speeds
than other seasons of the year. MISO has discussed the possibility of refining its capacity approach
within the next few years. But its current summer and annual percents have been used here.

1	CombustionTurbine (CT) Capital Cost	$502.00	/kW
2	Carrying Charge	14%	
3	Total Avoided Costs	$70.28	/kW / yr
4	Average Summer Capacity Factor	20.00%	(From MISO)
5	Costs Avoided	$14.06	(Ln 3 * Ln4)
6	Average Annual Capacity Factor	20.00%	(From MISO)
7	Availability Factor	95.00%	
8	Hours / Year	8,760	
9	Annual Hour of Operation	1,664	(Ln 6 * Ln 7 * Ln 8)
10	Capacity Credit ($ / kWh)	0.00845	(Ln 5 / Ln 9)