Direct Testimony and Schedules
Anne E. Heuer

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___(AEH-1)

Overall Revenue Requirements
Rate Base
Income Statement

June 30, 2009

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Anne E Heuer. My business address is 414 Nicollet Mall, Minneapolis, Minnesota 55401.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am the Manager of Revenue Analysis for Xcel Energy Services Inc. ("XES" or the "Service Company"). XES is the service company for the Xcel Energy Inc. holding company system and thus provides services to all of the operating utility subsidiaries of Xcel Energy Inc.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have been the manager of Revenue Analysis since January 2007. Prior to that date, I held a number of positions in the Regulatory Area, including Rate Consultant, Manager, Regulatory Development and Principal Rate Analyst. My qualifications and experience are summarized in my resume provided with my testimony as Exhibit___(AEH-1), Schedule 1.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company"), operating in South Dakota. The Company is a wholly-owned utility operating company subsidiary of Xcel Energy Inc.

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

A. I will provide testimony supporting the Company's financial data and its request for a general rate increase in the State of South Dakota retail electric jurisdiction. My testimony supports the income statement and rate base portions of the South Dakota cost of service.

Q. WERE THE SCHEDULES PRESENTED WITH YOUR TESTIMONY PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

Q. IN ADDITION TO THE SCHEDULES INCLUDED WITH THIS TESTIMONY, ARE THERE ADDITIONAL SCHEDULES YOU ARE SPONSORING?

A. Yes. I am sponsoring the following Statements and supporting Schedules, which are required by South Dakota Public Utilities Commission ("Commission") Rules (Sections 20:10:13:51 *et seq*.). These Statements and Schedules are located in Volume 1 of the Application:

A. Balance sheet
B. Income statement
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L. Other taxes

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M. Overall cost of service

N. Allocated cost of service

O. Comparison of cost of service

P. Fuel cost adjustment factor

R. Purchases from affiliated companies

To the extent the Commission's rules require a discussion of the content of these required Schedules, that discussion is provided with the required Schedule. Ms. Judy M. Poferl provides the description of utility operations required Schedule Q in her direct testimony. Mr. Robert B. Hevert provides the description of cost of capital and supports required Schedule G in his direct testimony.

Q. HAVE YOU RELIED ON INFORMATION PROVIDED BY OTHER WITNESSES IN PREPARING YOUR TESTIMONY AND SCHEDULES?

A. Yes. I relied on and incorporated information provided by other witnesses in this proceeding. Where applicable, I indicate in my testimony where the pro forma year cost information is based on information provided by other witnesses.

II. PRO FORMA YEAR REVENUE DEFICIENCY

Q. WHAT IS THE AMOUNT OF THE JURISDICTIONAL REVENUE REQUIREMENT FOR SOUTH DAKOTA?

A. The jurisdictional retail revenue requirement for South Dakota electric utility operations is $164,967,000, based on average rate base and net operating income for the 2008 pro forma year, as adjusted for known and measurable changes occurring in 2009 and 2010, making the 2008 pro forma year appropriate for the final rates that will go into effect in 2010. The jurisdictional retail revenue requirement is also based on the average 2008 capital structure, long-term debt and 11.25 percent cost of equity, based on the return on equity ("ROE") recommended by Mr. Hevert in his direct testimony.

Q. WHAT IS THE AMOUNT OF THE REVENUE DEFICIENCY FOR THE PRO FORMA YEAR?

A. The amount of the revenue deficiency for the pro forma year is $18,583,000. A summary of the revenue deficiency is shown in Exhibit___(AEH-1), Schedule 2 (Cost of Service Study ("COSS"), Page 5 of 6) as a comparison of the jurisdictional revenue requirement amount for the 2008 pro forma year with the revenues for the same period under present rates as approved by the Commission in Docket No. EL92-016. In order to earn an overall rate of return of 9.02 percent, South Dakota retail electric rates need to be increased by this amount, as developed in Exhibit __ (AEH-1), Schedule 2 (COSS, Page 5 of 6).

Q. WHAT IS THE PERCENTAGE INCREASE IN RETAIL REVENUES PROPOSED IN THIS CASE?

A. The revenue deficiency amount represents a 12.69 percent overall increase in retail revenues compared to 2008 retail revenues (adjusted for fuel recovery timing) at present rates as shown in Exhibit___(AEH-1), Schedule 2 (COSS, Page 5 of 6).

Q. DID YOU PREPARE A COSS THAT SUPPORTS THE REVENUE REQUIREMENT AMOUNT AND REVENUE DEFICIENCY FOR THE PRO FORMA YEAR?

A. Yes, under my direction, a COSS was prepared. Exhibit___(AEH-1), Schedule 2 (COSS Pages 1-6) contains a copy of the jurisdictional cost of service study.

Q. IS THE COMPANY PROPOSING ANY COST RECOVERY CHANGES THAT ARE REVENUE NEUTRAL TO THE RATEPAYERS?

A. Yes. The Company is proposing three changes that affect the base rate revenue deficiency without affecting the overall revenue requirement and the overall rates paid. Two of the changes, of approximately $2.9 million, reflect the shift of cost recovery from rate rider recovery to base rate recovery. The third rate design change that gives the appearance of an additional revenue requirement involves our proposal to recognize actual wholesale margins as a credit to the fuel cost revenue requirement rather than as a fixed credit to base rates. As I will explain later in my testimony, our proposed treatment of wholesale margin credits has the appearance of increasing retail rates by $1.8 million. However, the actual FCA credit that offsets that increase, based on actual experience, may be higher or lower than the $1.8 million. Therefore, $4.7 million of the $18.6 million being requested is a result of a change in the Company's method of rate recovery.

Q. PLEASE DESCRIBE THE FIRST OF THESE REVENUE NEUTRAL COST RECOVERY CHANGES INVOLVING RATE RIDERS.

A. The first requested cost recovery change is to move into base rates all projects previously approved by the Commission for recovery under the Transmission Cost Recovery ("TCR") Rider. The TCR Rider tariff was established in Docket No. EL07-007 to provide for the cost recovery of the jurisdictional portion of eligible investments in and expenses related to new or modified transmission resources.

Although the 2008 pro forma year revenue requirements for projects in service at the end of 2008 are approximately $1.2 million and are included in our base deficiency, there is no material customer impact in 2010, because the increase in the pro forma year deficiency for these projects will be offset by the reduction in the TCR Rider recovery for these projects in 2010.

Q. PLEASE DESCRIBE THE SECOND OF THESE REVENUE NEUTRAL COST RECOVERY RATE RIDER CHANGES.

A. The second proposed revenue neutral adjustment is to zero out the Environmental Cost Recovery ("ECR") Rider established in Docket No. EL07-026 and instead include recovery of the A.S. King ("King") Plant pollution control equipment and related expenses as part of our base rate request. This rider collects approximately $1.7 million annually from customers to pay the jurisdictional portion of eligible environmental expenditures.

Q. WHERE ARE THE RATE RIDER COST RECOVERY CHANGES SHOWN IN THE DETERMINATION OF PRO FORMA YEAR REVENUE REQUIREMENTS?

A. These two revenue neutral cost recovery rider changes are reflected in the 2008 unadjusted test year base data. The 2008 unadjusted test year data did not include recovery of the costs included in the TCR and ECR Riders, which became effective in February 2009. Therefore, no revenues are excluded from the 2008 information. Rather, the pro forma year deficiency includes the costs of these projects, and the TCR and ECR Riders will be adjusted to exclude recovery of the 2010 project revenue requirements. The Company will adjust the TCR and ECR Riders in a compliance filing at the end of the rate case to exclude 2010 recovery for projects currently included in the TCR and ECR Riders effective with implementation of final rates as a result of this docket, thus moving these project costs to base rate recovery in this case.

III. PRIMARY REASONS A RATE INCREASE IS NEEDED

Q. WHAT ARE THE PRIMARY DRIVERS FOR THE CURRENT REVENUE SHORTFALL?

A. The last year in which the Company had earnings in excess of its authorized rate of return was 2006. Consequently, the comparison I will provide is to 2006. Exhibit___(AEH-1), Schedule 3 (Case Drivers) contains a summary of the case drivers. The following Table 1 lists the primary drivers for an increase in the revenue requirement that have occurred since 2006.

Table 1

Case Drivers

Dollars in Millions	**Increase over 2006**
Capital Recovery	$15.8
Non-Fuel O&M Expense (includes Payroll Taxes)	$6.8
Net Margin	($1.2)
2006 Sufficiency	($2.8)
2008 Pro Forma Deficiency	$18.6

Q. THE LARGEST INCREASE IN REVENUE REQUIREMENTS RELATES TO CAPITAL NEEDS. PLEASE PROVIDE ADDITIONAL INFORMATION CONCERNING THE INCREASED CAPITAL INVESTMENTS MADE BY THE COMPANY SINCE 2006.

A. Table 2 provides the principal capital investments that have been made since 2006, resulting in an additional revenue requirement of $15.8 million.

Table 2

Case Drivers – Capital Recovery

Dollars in Millions	**Depreciation**	**Rate Base Rev Req.**	**Total Revenue Requirement**
Generation Projects			
King Refurbishment	$0.7	$2.5	$3.2
High Bridge Gas Conversion	$0.6	$1.8	$2.4
Riverside Gas Conversion	$0.4	$1.3	$1.7
Grand Meadow	$0.4	$0.9	$1.3
Other Generation projects	$1.1	$1.2	$2.3
Total Generation Projects	$3.2	$7.7	$10.9
South Dakota Distribution Projects	$0.4	$1.4	$1.8
Transmission Projects	$0.4	$1.6	$2.0
Total Identified Projects	$4.0	$10.7	$14.7
Other Increases / (Decreases)	($1.8)	$1.7	($0.1)
Total Rate Base and Depreciation	$2.2	$12.4	$14.6
Other Return & Tax Related			$1.2
Total Capital Recovery Items			$15.8

Q. PLEASE BRIEFLY DESCRIBE THE GENERATION PROJECTS.

A. A thorough discussion of the generation projects is included in the direct testimony of Mr. James Alders. In total, we have added a considerable amount of new generating capacity and made several critical improvements to the resources on the system since our last rate case in South Dakota, investing approximately $1.6 billion in generation plant in service since 2006. We believe we have done so in a cost effective manner and ensured efficient and reliable generation is available to serve customers while at the same time being environmentally responsible.

Q. PLEASE DESCRIBE THE SOUTH DAKOTA DISTRIBUTION PROJECTS.

A. These project costs were specific to South Dakota and were for the purpose of adding to or improving distribution service in South Dakota and, therefore, have been directly assigned to the South Dakota jurisdiction. The Company's average investment in South Dakota distribution net plant in service has increased by approximately $14.0 million since 2006.

Q. PLEASE DESCRIBE THE TRANSMISSION PROJECTS.

A. As described in Mr. Walter T. Grivna's direct testimony, the Company has made significant investments in transmission plants in two separate groups: (i) investments qualifying for rate rider treatment, primarily transmission investments supporting increased delivery of wind generation; and (ii) system performance and interconnection investments. In 2007 and 2008, recovery of the majority of transmission investments supporting wind generation took place through the TCR Rider. In 2010, approximately $1.2 million in transmission revenue requirements will move from the TCR Rider to base rates, representing approximately $241 million in total capital investment. However, Xcel Energy has also made significant investments in transmission projects that were not included in the TCR Rider. The Company has invested a total of $518 million in transmission projects mainly related to system performance and interconnection investments. The Company's average investment in transmission plant has increased by approximately $333 million since 2006 over and above the investments recovered through the TCR Rider for the South Dakota jurisdiction, resulting in an increase in plant investment of approximately $17 million for the South Dakota jurisdiction.

Q. WHAT ARE THE MAJOR INCREASES IN OPERATIONS AND MAINTENANCE ("O&M") COSTS?

A. As shown in Table 3, the major changes in O&M costs are non-fuel production expense, transmission expense, and Administration & General ("A&G").

Table 3

Non-Fuel O&M Cost Drivers

Dollars in Millions	Change in O&M from Cost of Service	Revenue Requirement Impact
Non-Fuel Production Expense	$3.4	$3.2
Transmission	$2.2	$1.5
Distribution	$0.0	$0.0
Customer Accounts	$0.2	$0.2
Customer Information	$0.1	$0.1
A&G	$1.4	$1.4
Payroll Taxes	$0.4	$0.4
Total	$7.7	$6.8

Q. PLEASE DESCRIBE TABLE 3.

A. Table 3 compares the change in O&M as reflected in the Cost of Service between 2006 and the 2008 pro forma year. Some O&M costs that are not recovered in the Fuel Clause are reflected as fuel expense in the Cost of Service rather than as O&M; for example, fuel handling. Table 3 also shows the revenue requirement change associated with the change in O&M. Changes in O&M generally result in a dollar for dollar impact to revenue requirements. However, production and transmission O&M costs that are partially offset with revenue have less than a dollar for dollar impact; for example, costs shared with NPS-Wisconsin Company through the Interchange Agreement, or transmission costs offset with MISO revenue. See Exhibit___(AEH-1), Schedule 3 (O&M Drivers, Page 2 of 2) for detail supporting the expense and revenue re-classes and interchange impacts.

Q. WHAT IS DRIVING THE CHANGE IN O&M EXPENSE?

A. The increase in revenue requirements for O&M expense is comprised principally of an increase in purchased capacity costs of $1.6 million, an increase in nuclear expenses of $1.5 million, non-nuclear labor of $1.3 million, and non-nuclear materials and chemicals cost of $0.5 million. The increase in revenue requirements for transmission expense of $1.5 million is generally offset by transmission revenues.

Q. DID YOU INCLUDE COMPARISONS OF THE CHANGE IN THE FUEL AND PURCHASED ENERGY EXPENSE AS PART OF THE O&M EXPENSE ANALYSIS?

A. No. Although the cost of fuel and purchased energy are considered to be an operating expense, recovery occurs through the separate fuel clause adjustment ("FCA") mechanism and true-up process.

Q. HOW MUCH HAS DEPRECIATION EXPENSE CHANGED SINCE 2006?

A. As shown in Exhibit___(AEH-1), Schedule 4 (Income Statement 2006 Reported & 2008 Pro Forma with Increase, Page 2 of 2), depreciation expense has increased $2.2 million since 2006, resulting from additional plant in service of $118 million, as can be seen in Exhibit____(AEH-1), Schedule 14, Page 1 of 2.

Q. HOW WAS DEPRECIATION EXPENSE AFFECTED BY THE LIFE EXTENSION OF THE MONTICELLO NUCLEAR GENERATING FACILITY?

A. In Docket No. E, G002/D-07-251, the Minnesota Public Utilities Commission ("Minnesota Commission") extended the life of the Monticello nuclear generating plant by 20 years to 2030. This change in life is consistent with the October 23, 2006 Minnesota Commission Order in Docket No. E002/CN-05-123 granting a Certificate of Need for spent fuel storage needed to operate the plant an additional 20 years beyond 2010. The extended life of this facility decreased annual depreciation expense for the Company by $25.8 million, or approximately $1.3 million for the South Dakota electric jurisdiction.

Q. HOW WAS DEPRECIATION EXPENSE AFFECTED BY THE LIFE EXTENSION OF THE SHERCO GENERATING FACILITY?

A. In Docket No. E, G002/D-08-189, the Minnesota Commission extended by 3 years the life of the Sherco generating plant units 1 and 2 and extended by 2.2 years the life of Sherco Unit 3, resulting in a 15-year remaining life for all three units. The extended life of this facility decreased annual depreciation expense for the Company by $6.3 million, or approximately $0.3 million for the South Dakota electric jurisdiction.

IV. DATA PROVIDED AND SELECTION OF PRO FORMA YEAR

Q. PLEASE DEFINE THE FISCAL PERIODS FOR WHICH FINANCIAL DATA IS PROVIDED IN THIS PROCEEDING.

A. Following the rules of the Commission, financial data is provided for the calendar year 2008 (the "unadjusted test year") and the 2008 pro forma year that includes 2009 and 2010 known and measurable adjustments.

Financial data is first normalized to remove any unusual conditions in the actual year (e.g. weather normalization) that should be adjusted for rate setting purposes. Next, the actual year is adjusted for regulatory adjustments (*e.g.* charitable donations, organizational dues, etc.). Finally, I make pro forma adjustments to reflect known and measurable changes occurring in 2009 and 2010 that should be included, so that final rates, which will become effective in 2010, will reflect the Company's revenues and expenses at the time the rates go into effect.

I provide schedules showing for the unadjusted 2008 test year: the actual unadjusted average rate base consisting of the same rate base components; unadjusted operating income; overall rate of return; the calculation of required income; the income deficiency and revenue requirements. Separate rate base and income statement bridge schedules identify the adjustments described in my testimony to the unadjusted 2008 test year that create the pro forma year reflecting: the normalizing adjustments; regulatory adjustments; and the pro forma adjustments for 2009 and 2010.

In this rate case, the Company proposes to transfer recovery from the TCR and ECR Riders during 2009 to base rates. These transfers cause corresponding changes in the costs to be recovered in the rate riders.

V. JURISDICTIONAL COST OF SERVICE STUDY

A. Components of Jurisdictional COSS

Q. PLEASE DESCRIBE THE COMPONENTS OF THE JURISDICTIONAL COST OF SERVICE STUDY FOR THE 2008 PRO FORMA YEAR.

A. The complete jurisdictional cost of service is included in Volume 4 (Workpapers) of this filing. The jurisdictional cost of service includes: a revenue requirement, rate base, income statement, income tax, and a cash working capital computation.

Q. PLEASE DESCRIBE THE JURISDICTIONAL COST OF SERVICE SUMMARY SCHEDULES.

A. The pro forma year jurisdictional cost of service summary is included at Exhibit___(AEH-1), Schedule 2 (COSS, Pages 1-6). In order to facilitate a comparison to the unadjusted 2008 test year, we have also included the unadjusted 2008 test year jurisdictional cost of service summary as Exhibit ___(AEH-1), Schedule 2A (COSS, Pages 1-6).

- The cover page identifies the South Dakota retail jurisdiction requested ROE, and shows the earned ROE under current rates, the revenue deficiency, and the percent of increase that would result if rates were increased to earn the requested ROE (in this case 11.25 percent).

- The "Rate Base Summary" for total Company electric operations and the South Dakota jurisdiction is shown on Schedule 2 (COSS, Page 2).
- An "Income Statement Summary" for total Company electric operations and the South Dakota jurisdiction is shown on Schedule 2 (COSS, Page 3). The income statement shows the determination of total operating income at present authorized retail rates.
- The "Income Tax Summary" for total Company electric operations and the South Dakota jurisdiction is shown on Schedule 2 (COSS, Page 4). The schedule shows adjustments to book income necessary to determine state and federal taxable income. The federal and state income tax calculations are carried back to the income statement on Schedule 2 (COSS, Page 3).
- The "Revenue Requirement and Return Summary" for total Company electric operations and the South Dakota jurisdiction is shown on Schedule 2 (COSS, Page 5). Specifically, the schedule shows: the earned overall rate of return on rate base, the earned ROE, the revenue deficiency that needs to be recovered to enable the South Dakota jurisdiction electric operations to earn the requested ROE, and the total revenue requirements and the percent of increase that would result by increasing retail billing rates by the amount of the revenue deficiency.
- The computation of cash working capital, Schedule 2 (COSS, Page 6), is carried back to the rate base on Schedule 2 (COSS, Page 2).

Q. ARE THE REVENUE CONVERSION FACTOR CALCULATION AND THE SOUTH DAKOTA COMPOSITE INCOME TAX RATES INCLUDED IN THIS FILING?

A. Yes. The revenue conversion factor calculation, using a South Dakota composite tax rate of 35 percent, is included in my exhibits at Exhibit___ (AEH-1) Schedule 2 (COSS, Page 5).

B. Income Statement Schedules

Q. PLEASE EXPLAIN HOW THE INTEREST DEDUCTION FOR DETERMINING TAXABLE INCOME IS CALCULATED.

A. The interest deduction applicable to the income tax calculation is the result of a calculation commonly referred to as "interest synchronization." The amount of interest deducted for income tax purposes is the weighted cost of debt capital multiplied by the average rate base.

Q. DESCRIBE THE SCHEDULES IN YOUR EXHIBITS THAT ARE RELATED TO THE INCOME STATEMENT.

A. I have provided two schedules related to the income statements: Exhibit___(AEH-1), Schedule 4 (Income Statement 2006 Reported & 2008 Pro Forma with Increase); and Exhibit ___(AEH-1), Schedule 5, Page 2 of 2 (Income Statement Comparison - 2008 Pro Forma to Unadjusted Test Year).

Q. WHAT DOES EXHIBIT ___(AEH-1), SCHEDULE 4 INCLUDE?

A. Schedule 4 (Income Statement 2006 Reported & 2008 Pro Forma with Increase) consists of two comparative income statements for the pro forma year. Page 1 of Schedule 4 is a comparative income statement for the 2008 pro forma year showing the income effect of present authorized rates and proposed rates. This comparative income statement was prepared from the results of the jurisdictional cost of service study and includes the revenue deficiency in the South Dakota jurisdiction electric utility operations. Page 2 of Schedule 4 shows a comparative income statement of the 2008 pro forma year after the proposed rate increase, and the 2006 actual year as reported.

C. Compliance with Commission Orders

Q. DID YOU REVIEW COMMISSION ORDERS AS PART OF THE DEVELOPMENT OF THE PRO FORMA YEAR REVENUE REQUIREMENT?

A. Yes. The following list briefly describes the various Commission Orders that were reviewed and addressed in preparing the pro forma year. I will discuss required adjustments relating to these later in my testimony. The Compliance Matrix included in the testimony of Ms. Poferl, Exhibit ___(JMP-1), Schedule 2, documents how our rate case filing includes information submitted in compliance with these prior Commission orders.

- Tree Trimming - The Commission's Order in Docket No. EL92-016 contains the following statement: "Company acknowledges that if the amount of tree trimming expense incurred until the time new general rates become effective is less than $815,000 on an annual basis, the difference between the actual tree trimming expense and the agreed upon amount ($815,000 x No. of years from 01/01/93) may be recaptured and returned to the Company's customers in its next general rate proceeding." As shown in Exhibit___(AEH), Schedule 6, the Company has spent on average annual tree trimming expenditures of $1,088,000, exceeding the ordered minimum. Therefore, the Company has not made any adjustment in this rate proceeding to recapture and return any amounts related to unexpended tree trimming costs.

- Post Retirement Medical Benefits – Pay as you go – The Commission's Order in Docket No. EL-92-016 contains the following statement: "The Settlement Agreement rate levels include Post Retirement Benefits other than Pensions ("PBOP") under the cash or "Pay as you go" method recommended by Staff. The parties agree that, if the Commission should approve for inclusion in rates, PBOP's calculated under the accrual method indicated in FAS 106, or under some other method, the Settlement Agreement rate levels shall be modified to include the approved levels of PBOP expenses." The Commission did not approve use of the accrual method indicated in SFAS 106. This rate proceeding includes adjustments to reflect PBOP on a pay as you go basis. These adjustments are included in my bridge schedules, Exhibit___(AEH-1), Schedule 7b.

- Renewable Development Fund Amortization Request - The Commission's Order in Docket No. EL04-015 contains the following statement: "Xcel shall accumulate these costs in a separate account, by vintage, from 2004 forward, including carrying charges based upon the rate of return last allowed by this Commission, for the Commission's further consideration in the form of a potentially recoverable regulatory asset. The Commission's consideration for recovery of these costs shall take place within Xcel's next general filing for a rate change." In this rate proceeding, we request an amortization over four years designed to recover the accumulated regulatory asset balance for eligible Renewable Development Fund project costs. Our pro forma year revenue requirement includes adjustments reflecting this amortization, which are supported further in the section E-3 below, which describes known and measurable adjustments and are included in my income statement bridge schedule, Exhibit___(AEH-1), Schedule 7b.

- Nuclear Refueling Outage Change of Accounting - The Commission's Order in Docket No. EL07-035 contains the following statement: "Xcel's petition is approved with the condition that the deferral/amortization accounting method and the resulting creation of a regulatory asset (the deferred balance) shall not preclude Commission review of these amounts for reasonableness for rate recovery in any determination of rates, including both rate filings by the company and rate reviews initiated by the Commission." The unadjusted test year, as well as the pro forma year, reflects the change of accounting for nuclear refueling outage costs approved by the Commission in this order. Our pro forma year also includes a normalization adjustment, reflecting that the unadjusted test year does not include an amortization of refueling outage costs in each month for each nuclear unit. This adjustment is shown on my income statement bridge schedule, Exhibit___(AEH-1), Schedule 7b.

D. Jurisdictional Allocations.

Q. PLEASE BRIEFLY DESCRIBE THE METHODS USED TO ALLOCATE COSTS TO THE COMPANY'S ELECTRIC UTILITY OPERATIONS.

A. The pro forma year includes both costs incurred directly by the Company's electric operating business and costs directly assigned or allocated by the Service Company for corporate functions (*e.g.,* accounting, human resources, law, etc.). The Service Company cost allocation and billing process is subject to

Federal Energy Regulatory Commission ("FERC") jurisdiction and authorization under a Utility Services Agreement between Xcel Energy and the Service Company. O&M cost assignments and allocations were the same as used by the Company in the recent Minnesota electric rate case filed with the Minnesota Commission (MPUC Docket No. E002/GR-08-1065) and the recently completed rate case filed with the North Dakota Public Service Commission (PU-07-776). Non-O&M costs include such items as book depreciation expense, deferred income taxes and property taxes. All of the common investments and their related costs, be they software or other common investments, are evaluated by asset location as to whether they should be direct assigned to Electric or Gas, or allocated based on Customers, Customer Bills, Transportation Studies, or the Three Factor Allocator (revenues, utility plant in service, and supervised O&M). Additional information regarding this process and the reason for selecting a particular allocator is also included in the Cost Assignment and Allocation Manual ("CAAM") included in Volume 5 of this Application.

Q. PLEASE DESCRIBE THE METHODS USED TO ALLOCATE COSTS FOR ELECTRIC UTILITY OPERATIONS IN SOUTH DAKOTA.

A. Expenses are generally determined on a functional basis (*i.e.* Production, Transmission, Distribution, Customer Accounts, Customer Information, Sales, Administrative and General). These functional amounts are directly assigned to the South Dakota jurisdiction electric utility operations or allocated to the electric operations based on cost causation. A summary and description of the allocation factors used to allocate expenses and capital items to the South Dakota jurisdictional electric operations income statement and rate base are contained in the CAAM.

Q. PLEASE EXPLAIN THE PROCESS FOR ASSIGNING THE COMPANY'S INVESTMENT IN ELECTRIC PLANT TO THE SOUTH DAKOTA JURISDICTION.

A. A summary and description of the allocation factors used to allocate expenses and capital items to the South Dakota jurisdictional electric operations income statement and rate base is contained in Exhibit___(AEH-1) Schedule 8 (Allocation Factors). Plant investments are accounted for in the manner prescribed by the FERC Uniform System of Accounts. Detailed records are maintained on a functional basis (*i.e.* Production, Transmission, Distribution, etc.). The capital budgets, from which the projected plant balances in rate base were developed, are also prepared on a functional basis. These functional amounts are assigned to the appropriate jurisdiction directly, or allocated based on the use of such assets in providing electric service in a particular jurisdiction and the underlying elements of cost causation.

Q. PLEASE EXPLAIN THE NEED FOR JURISDICTIONALLY ALLOCATING THE INVESTMENT IN PRODUCTION AND TRANSMISSION FACILITIES.

A. The Company's production and transmission system is designed, built, and operated to provide an integrated source of electricity shared by the Company's electric customers first between the Company and Northern States Power Company – Wisconsin ("NSP-Wisconsin") operating companies through the Interchange Agreement approved by the FERC and discussed later in my testimony. With respect to allocations involving transmission and generation, it is first necessary to allocate expenses and investments between NSP-Wisconsin and NSP-Minnesota. Those allocations are performed in accordance with the Interchange Agreement. Pursuant to that Interchange Agreement, approximately 16 percent of the costs are allocated to NSP-

Wisconsin with a remaining 84 percent allocated to NSP-Minnesota. The NSP-Minnesota costs are then allocated between South Dakota, Minnesota and North Dakota and a small group of wholesale customers taking service under rates regulated by FERC. The result is that those investments and expenses that are subject to the Interchange Agreement are allocated approximately 4.4 percent to South Dakota. Those investments and expenses that are not subject to the Interchange Agreement are allocated approximately 5.2 percent to South Dakota.

Q. PLEASE DESCRIBE THE METHODS OF ALLOCATING COSTS BETWEEN THE FOUR JURISDICTIONS SERVED BY NSP-MINNESOTA.

A. To allocate investment in production and bulk transmission facilities to jurisdictional areas from those allocated to NSP-Minnesota, I used the average of the 12-monthly coincident peak demands ("12 CP Method") to the actual year ended December 31, 2008. The Commission accepted this method of allocation in previous rate proceedings (Docket Nos. EL92-016, F-3764 and F-3780). It is reasonable to use coincident peak demands as an allocation basis, because these facilities are designed to meet peak requirements and operate as an integrated system across all jurisdictions. Similarly, fixed operating costs, which are not sensitive to changes in the amount of energy produced, also have been allocated on a demand basis. Expenses and investment related to units of output, such as nuclear fuel, were allocated on the basis of energy requirements. Items of plant that serve only the jurisdiction in which they are located are directly assigned to that jurisdiction.

Q. HOW WERE THE DISTRIBUTION INVESTMENT AMOUNTS ASSIGNED TO THE SOUTH DAKOTA JURISDICTION?

A. The Company's electric distribution plant investment amounts have been directly assigned based upon the jurisdiction(s) served by each of the individual distribution facilities.

Q. PLEASE DESCRIBE ANY ADJUSTMENTS MADE TO THE ALLOCATION FACTORS FOR USE IN THE PRO FORMA YEAR ENDED DECEMBER 31, 2008.

A. To allocate investment in production and bulk transmission facilities for the 2008 year, I used the 2008 12-month coincident peak demands and energy allocators unadjusted for weather. The same customer allocation factor is used for the unadjusted and pro forma years ending December 31, 2008. The allocation factors used in the development of data in the unadjusted and pro forma year-end December 31, 2008 may be found on Exhibit___(AEH-1) Schedule 8 (Allocation Factors). The revenues and expenses allocated to South Dakota can be found on Exhibit___(AEH-1), Schedule 2 (Cost of Service Study ("COSS"), Page 3 of 6) for the pro forma year and Exhibit___(AEH-1), Schedule 2A (Unadjusted Cost of Service Study ("COSS"), Page 3 of 6) for the unadjusted test year.

E. Pro Forma Adjustments.

Q. HAVE YOU MADE PRO FORMA ADJUSTMENTS TO THE 2008 ACTUAL YEAR TO DEVELOP A PRO FORMA YEAR?

A. Yes. It was necessary to make three categories of changes to the 2008 actual year to make the resulting pro forma 2008 test year appropriate for setting rates that will be finalized and applied to service provided in 2010 and after. The first category of change is to normalize the 2008 data. The second category of change is to reflect prior regulatory decisions for what may be appropriately included in a pro forma year. The third category of changes is for known and measurable changes occurring in 2009 and 2010 that need to be reflected in order for rates to be appropriate when charged in 2010.

A list of these pro forma year adjustments is shown on Exhibit___(AEH-1), Schedule 9 (Rate Case adjustments). I will also discuss each adjustment later in my testimony. In addition, I have provided a bridge schedule (Exhibit___(AEH-1), Schedule 7a (Rate Base) and Exhibit___(AEH-1), Schedule 7b (Income Statement) that shows all normalized, regulatory and known and measurable changes adjustments included in Exhibit___(AEH-1), Schedule 9.

1. Pro Forma Year Normalizing Adjustments.

Q. YOU MENTIONED THAT YOU MADE ADJUSTMENTS TO THE 2008 ACTUAL DATA FOR THE PURPOSE OF NORMALIZING THE EXPENSES. PLEASE EXPLAIN.

A. The purpose of the pro forma year is to set rates based on a representative set of revenues and expenses. Consequently, it is necessary to normalize certain 2008 actual data. I made the following adjustments to the 2008 actual data to normalize them:

1) Weather Normalization;
2) Fuel Recovery Timing;
3) Generation that went into service in 2008;
4) Incentive Compensation;
5) Nuclear Fuel Outages;
6) 2008 Insurance Credit;

7) Emission Credit (Sale of SO_2 Allowances); and

8) Manufacture Production Deduction.

Q. WHAT IS THE WEATHER NORMALIZATION ADJUSTMENT?

A. Our 2008 actual year reflects actual sales. Sales are affected by weather. Therefore, it was necessary to weather normalize the retail sales margin. This was performed by Ms. Jannell E. Marks. This adjustment reduces fuel expense by $902,000. This margin adjustment was made to the fuel expense so as not to change present revenues.

Q. DO RETAIL OPERATING REVENUES REFLECT CALENDAR MONTH SALES VOLUMES IN THE PRO FORMA YEAR?

A. Yes. Non-fuel unadjusted test year revenues are on a calendar-month basis. However, the unadjusted test year reflects fuel revenues and fuel expenses that include a recovery lag of approximately 2.5 months. A pro forma adjustment was made to adjust the timing of both fuel revenue and expenses to an actual 2008 calendar-month basis. This adjustment has no impact on the revenue deficiency as the adjustment to revenue is offset by an equal adjustment to fuel expense. The adjustment reduces both retail revenues and fuel expense by $495,000, resulting in no change to revenue requirements.

Q. IS THE COMPANY MAKING ANY OTHER SALES ADJUSTMENTS FOR THE PRO FORMA YEAR 2009 OR 2010?

A. No. As explained by Ms. Marks, the 2009 forecast demonstrates a loss in retail sales. We believe this is the direct result of the current economy, and while we believe that sales may recover to 2008 levels sometime in 2010, that is speculative at this time and does not arise to the level of a known and measurable change upon which rates should be based. Consequently, we have not made any pro forma adjustments related to sales.

Q. WHAT ADJUSTMENTS HAVE BEEN MADE WITH RESPECT TO GENERATION THAT WENT INTO OPERATION DURING 2008?

A. The King plant went into operation in July 2007, the High Bridge plant went into service in May 2008, and the Grand Meadow wind farm went into operation in November 2008. Consequently, the 2008 actual year only reflects a portion of the associated investment and operating expenses that the Company will incur in 2009, and 2010 when the final rates go into effect. Therefore, we have included a full year of investment and expense for each of these plants. We used 2009 pro forma information to determine the level of investment and expenses to include. Consequently, we have also used end of year 2009 accumulated depreciation so that there is proper matching. This increases the revenue requirement by $2,415,000.

Q. DID YOU MAKE ANY SIMILAR ADJUSTMENTS FOR OTHER CAPITAL PROJECTS THAT OCCURRED DURING 2008?

A. Yes. There were capital projects that occurred during 2008 for Prairie Island. We replaced the 2008 investment and expenses with 2009 investments and expenses, along with end of year 2009 accumulated depreciation. This increases the revenue requirement by $198,000.

Q. WHY DID YOU NORMALIZE THE 2008 INCENTIVE PAYMENT?

A. During 2008, the Company did not pay any annual incentive compensation. This is of course abnormal. It is the only year since 2000 in which no incentive payment was made. Therefore, it is necessary for a more normal amount to be included in the pro forma year. We determined that the average annual incentive amount experienced over the last four years would represent a normalized level. During the four-year period of 2005-2008 the actual incentive payments made were, on average, 70 percent of the budgeted amount. We then multiplied the 2009 incentive compensation target amount by 70 percent. See my workpapers at Volume 4 for this calculation. The result is an increase in pro forma year expense of $839,000.

We also removed from the unadjusted test year 2008 the long-term portion of officer's incentive compensation, and any non-corporate incentive plan costs. This adjustment results in a reduction to pro forma year expense of $212,000.

Q. PLEASE DESCRIBE THE NUCLEAR OUTAGE CHANGE OF ACCOUNTING ADJUSTMENT.

A. The Commission approved our request to change our method of accounting for costs associated with routine nuclear refueling outages in Docket No. EL07-035 effective January 1, 2008. This adjustment reflects two items: (i) the rate base impact of the change of accounting; and (ii) a normalization adjustment. 2008 reflects the first year of this change of accounting. Because the actuals reflect the phase-in of this method, we are proposing an adjustment to pro forma year expenses to reflect a normalized level of nuclear refueling outage expenses that includes costs for all three nuclear generating units. The 2008 amortization reflects only two scheduled outages in 2008, both at the Prairie Island plant, Units 1 & 2. Under the deferral-and-amortization methodology, the Company would record amortized refueling outage expenses of $675,000 in 2008 for the State of South Dakota, which would not reflect the ongoing expense level, but rather, the start-up amortization amount at its lowest point in which not all of the plants have been through a refueling outage. The amortized South Dakota jurisdictional expense amount that represents a more normal level of expense, reflecting a full cycle of refueling outages, is $2,241,000. Therefore, we made a pro forma adjustment of $1,567,000 to reflect this more normal level of outage expense.

The combination of these two components of this adjustment also affects the following rate base items: (i) accumulated deferred income taxes increased by $374,000; and (ii) other rate base increased by $916,000. The combined adjustment increases the South Dakota revenue requirement by $1,489,000.

Q. WHY DID YOU MAKE AN INSURANCE CREDIT ADJUSTMENT?

A. The Company received a one-time insurance credit of $47,000. Because similar credits will not be received in future years, it is necessary to remove this credit in order for 2008 to be representative of future revenue requirements.

Q. WHAT IS THE SO2 EMISSION ALLOWANCE SALES ADJUSTMENT?

A. We deferred until this rate case the recognition of revenues received from the sale of SO2 emission allowances. As of December 31, 2008, the Company has deferred $219,000 as the South Dakota share of these allowance revenues. We propose to amortize this amount over four years at $55,000 per year. In addition, we have included an ongoing revenue amortization level based on the five-year average of SO2 emission allowance sales (2008 year end balance less 2003 year end balance divided by five), or $29,000 per year. Thus, our pro forma year includes an annual amortization level of $84,000, decreasing overall revenue requirements.

Q. WHY IS A MANUFACTURE PRODUCTION CREDIT ADJUSTMENT APPROPRIATE?

A. The Manufacture Production Tax Deduction is 6 percent of production related federal taxable income. Because the net affect of the pro forma adjustments to the unadjusted test year result in a reduction in production federal taxable income, the Manufacture Production Tax Deduction is reduced by $69,000, increasing revenue requirements by $37,000.

2. Pro Forma Year Adjustments Reflecting Regulatory Practices

Q. YOU MENTIONED THAT YOU MADE ADJUSTMENTS TO THE 2008 ACTUAL DATA FOR CERTAIN REGULATORY ADJUSTMENTS. PLEASE IDENTIFY THESE ADJUSTMENTS.

A. I made the following adjustments to the 2008 actual data to comply with the regulatory adjustments made by the Commission:

1) Advertising Expenses;
2) Economic Development Costs;
3) Interest on Customer Deposits;
4) Professional and Utility Association Dues;
5) Charitable Contributions/Donations;
6) Configuration Management;
7) Remove Demand Side Management expense;
8) SFAS 106 Post Retirement Medical;
9) Cash Working Capital; and
10) Rate Case Expense.

I will discuss each of these adjustments.

Q. WHAT ADVERTISING ADJUSTMENT DID YOU MAKE?

A. The Company is required to reduce general and administrative expense for brand and image advertising costs that are not allowed to be recovered from South Dakota customers. The allowed advertising expense is primarily related to providing information on safety and customer information. Representative advertisements for which we are asking recovery and the relative dollar values are included in Volume 1. Because we recorded the cost of brand and image advertising below the line, most of those costs were not included in 2008 unadjusted test year expenses. However, I removed $191,000 for advertisements for the purpose of promoting the Company's brand or image that were included in the unadjusted test year expenses.

Q. HOW HAVE YOU TREATED ECONOMIC DEVELOPMENT COSTS?

A. In its last rate case, the Company was authorized to recover 50 percent of its then current economic development expense of $100,000 incurred for the benefit of South Dakota communities. During the merger between Northern States Power and New Century Energy, the merged company agreed to spend an additional $100,000 on economic development in South Dakota. As a result, we propose to continue spending $200,000 on economic development for the benefit of South Dakota communities and request 50 percent recovery. Consequently, $100,000 of the total $200,000 of economic development costs has been included in the pro forma year.

Q. WHY DID YOU MAKE AN ADJUSTMENT FOR INTEREST ON CUSTOMER DEPOSITS?

A. Customer deposits are treated as customer supplied capital and thus it is appropriate to pay ratepayers a return on their investment. The average balance of customer deposits is deducted from rate base while at the same time a pro forma year operating expense is increased to permit the recovery of the interest paid on these deposits. The adjustment results in a $4,000 increase in the revenue requirement.

Q. WHY DID YOU MAKE AN ADJUSTMENT TO ASSOCIATION DUES?

A. We are requesting recovery of our association dues, but not that portion of the dues that pays for social organizations or lobbying activities. Lobbying expenses are recorded below the line and consequently we do not have a separate lobbying adjustment. However, we discovered that one of our dues payments included a lobbying payment that was inadvertently recorded above the line and consequently a $1,000 adjustment was made to remove that payment.

Q. HOW HAVE YOU REFLECTED CHARITABLE CONTRIBUTIONS?

A. We are requesting recovery of 50 percent of our charitable contributions made to South Dakota charities and institutions. Because we recorded those contributions below the line, we have made an adjustment to increase pro forma year expense by $59,000. We are aware that the Commission has historically not approved charitable contributions, however, in light of the current economic conditions we believe that these efforts should be treated in the same light as economic development and allowed partial recovery as is currently allowed in some of our jurisdictions. A listing of the organizations to which the Company contributed in 2008 is included in Exhibit___(AEH-1), Schedule 10.

Q. PLEASE EXPLAIN THE CONFIGURATION MANAGEMENT ADJUSTMENT.

A. Consistent with the Settlement Agreement in Docket No. EL90-13, we have made a revenue requirement adjustment of $63,000 to reflect the continued amortization of Configuration Management expenses previously deferred and allowed recovery over a 20-year period.

Q. PLEASE EXPLAIN THE DEMAND SIDE MANAGEMENT ADJUSTMENT.

A. The Company is currently requesting, in Docket EL07-036, recovery of its demand side management expenses through a separate rider. Consequently, to avoid double recovery I removed $83,000 in demand side management expenses from the pro forma year.

Q. WHY HAVE YOU INCLUDED AN ADJUSTMENT FOR STATEMENT OF FINANCIAL STANDARD ("SFAS") 106 POST RETIREMENT MEDICAL EXPENSES?

A. Prior to the issuance of SFAS 106, businesses recorded post-retirement benefit expenses other than pensions (primarily health care provided to retirees) on a pay-as-you-go basis. SFAS 106, which became effective in 1993, established an accrual accounting process under which the future projected cost of OPEBs was recognized at the time the benefits were earned. It also established a transition period of up to 30 years to recover the amounts that had not been previously recovered under the pay-as-you-go method but which would have been recognized under the SFAS 106 accrual method.

Fundamentally, using an actuarial estimate, the annual recorded amount is the current period expense for future postretirement benefits, such that the expense is fully recovered over the working life of the future retiree. The actuarially estimated amount is debited as expense and credited to the accumulated provision for OPEBs, creating a liability. When actual post-retirement health care costs are incurred, the liability is debited and cash is credited to pay the bill.

Q. HAS THE COMMISSION ADOPTED SFAS 106 FOR RATEMAKING PURPOSES?

A. No. In a January 26, 1993 Order in Docket No. EL92-016, the Commission declined to adopt SFAS 106 for ratemaking purposes. The Commission was concerned because the accrual method would sharply increase the annual expense and would create a mismatch of service costs and benefits by allowing amortization of past-period transition costs. The Commission was also concerned that the actuarial projections of future OPEB expenses were not sufficiently reliable to qualify as known and measurable expenses.

Q. WHAT ADJUSTMENT IS THE COMPANY REQUESTING IN THIS RATE REQUEST?

A. The Company is required to comply with SFAS 106 for financial reporting purposes. In addition, the Company is required to use SFAS 106 in the other jurisdictions in which it provides service. Consequently, it was necessary to convert from recognition of SFAS 106 to Pay-Go in the 2008 pro forma year. This increases revenue requirements by $323,000.

Q. PLEASE EXPLAIN THE CASH WORKING CAPITAL ADJUSTMENT.

A. We performed a lead/lag study to determine to what extent payment of expenses occurs before reimbursement and when payment of the expense occurs after reimbursement. Collectively, it was determined that reimbursement lags payment of the expense, requiring less investment to cover those expenses after all adjustment were considered. The resulting reduction in investment decreases the revenue requirement by $50,000. The lead/lag study results are provided as Exhibit___(AEH-1), Schedule 2 (COSS, Page 6 of 6). The entire study is included in Volume 5 of this Application.

Q. PLEASE EXPLAIN THE AMORTIZATION OF RATE CASE EXPENSES IN THIS PROCEEDING.

A. The Company is projecting direct expenses associated with this rate case docket at $294,000. We propose to amortize these expenses over a three year period to match the time period that we could reasonably expect to file our next electric rate case. Amortizing these expenses over a three-year period results in an annual amortization of $98,000. The development of our projected rate case costs is shown on Exhibit __ (AEH-1), Schedule 11 (Rate Case Expenses).

3. Known and Measurable Pro Forma Adjustments

Q. DID YOU FURTHER ADJUST THE BASE 2008 DATA TO DEVELOP THE PRO FORMA YEAR?

A. Yes. I made additional pro forma known and measurable adjustments to the unadjusted 2008 test year data. These adjustments are necessary to have final rates reflect the cost of service at the time the final rates become effective. These adjustments are:

1) New generation that went into operation in 2009;
2) Postal increases in 2009 and 2010;
3) Union wage increase including payroll tax in 2009 and 2010;
4) Non-union wage increase including payroll tax in 2009;
5) Nuclear mandates (Fitness for Duty requirements);
6) Prairie Island life extension of 3 years (affecting depreciation, end of life fuel and decommissioning);

7) Joint Zonal Pricing (GRE's change in expenses charged the Company);
8) Service Company Pension;
9) Active Health Care;
10) Employee expense reductions;
11) Private Nuclear Storage Facility;
12) Renewable Development Fund;
13) MISO Schedule 24; and
14) Wholesale margins.

Q. WHAT STANDARD DO YOU APPLY WHEN ASSESSING WHETHER TO MAKE AN ADJUSTMENT FOR A KNOWN AND MEASURABLE CHANGE?

A. In order to be considered for a known and measurable change, there needs to be compelling evidence that the adjustment yields a more accurate ongoing level of cost. Factors such as the following would be considered:

- A signed contract in place (e.g. union wage increases);
- Action already taken by the Company (e.g. employee expense reductions);
- Proposed changes in cost recovery (e.g. Wholesale Margins and MISO Schedule 24);
- 2009 rate changes already in effect (e.g. postal increases);
- Major capital projects with an actual or projected 2009 in service date.

Q. WHAT ADJUSTMENTS DID YOU MAKE WITH RESPECT TO GENERATION THAT BECAME OPERATIONAL IN 2009?

A. Just as it was necessary to normalize the 2008 actual year to reflect new generation that came on line in 2008, it is necessary to reflect in rates new generation facilities that came on line in 2009. These adjustments include the Riverside plant that came on line in March 2009; and investments made to

Prairie Island during 2009. In both cases, we also made a full year of accumulated depreciation adjustment. The impact is $3.2 million, exclusive of the Riverside and Prairie Island, which are discussed below.

For Riverside, we used 2010 end of year investment to capture a full year of operation. Consequently, the accumulated depreciation adjustment is from March 2009 through December 2010. The net impact of this adjustment is an increase in revenue requirements of $608,000.

The Prairie Island nuclear generating facility included investments through the end of 2008 as well as 2009 major capital improvements. The 2009 improvements for safety, monitoring and equipment replacement represent an additional plant investment of approximately $1.0 million for the South Dakota jurisdiction, creating an additional revenue requirement of $466,000.

Q. WHY DID YOU INCLUDE POSTAGE INCREASES?

A. We have included an increase in postage expense due to the announced increase in 2009 postal rates. In addition, we have applied the two-year average (2007 and 2008) increase in postage rates to 2010. The resulting expense increase for 2009 is $15,000 and for 2010 it is $17,000.

Q. PLEASE EXPLAIN THE UNION WAGE INCREASES.

A. We have completed negotiations with our union employees and the wage increases for 2009 and 2010 are known and measurable. The increase for 2009 is 3.5 percent and the increase for 2010 is 4.0 percent. The increased expense, including payroll tax, is $607,000.

Q. WHAT NON-UNION WAGE INCREASE ARE YOU INCLUDING?

A. There are two annualizing adjustments made to non-union wages. First we annualized the 2008 annual wage increase, which became effective March 2008. Second, effective July 1, 2009, non-union employees received an average 2 percent merit wage increase. A 3.5 percent merit increase had been budgeted to take effect January 1, 2009, but due to the effect of the economy that increase was both delayed and reduced. The effect of these two annualizing adjustments, including payroll taxes, is $238,000.

Q. PLEASE DESCRIBE THE NUCLEAR MANDATES.

A. As explained in the direct testimony of Mr. Alders, the Nuclear Regulatory Commission ("NRC") has enacted Fitness for Duty requirements, 10 C.F.R. 26, that take effect in October 2009. Our 2009 budget includes approximately $5.1 million (total Company) in ongoing costs to support implementation of this new regulatory requirement. Although the new rule will not be effective until October 2009, we are required to be in compliance with the rule on its effective date. Therefore, that required the Company to begin hiring as early as 2008, and commence training and qualification of additional staff so that they will be available to meet our new requirements on the effective date of implementation. Initial estimates are that this may require up to 44 additional staff at Monticello and up to 37 additional staff at Prairie Island. The adjustment to the 2008 pro forma year for South Dakota is $220,000 for these activities.

Q. WHY DID YOU ADJUST THE PRO FORMA YEAR TO ASSUME A THREE YEAR LIFE EXTENSION FOR PRAIRIE ISLAND?

A. The current licenses for Prairie Island Units 1 and 2 will expire in 2013 and 2014. The Company has pending a request for a 20-year life extension for each unit. While we are cautiously optimistic, the request is contested and requires approval by the Minnesota Commission, the NRC, and any Certificate of Need for additional on-site storage is subject to rejection by the Minnesota legislature. These approvals are expected to be received by 2010 but could extend to the end of the Minnesota legislative session in 2011.

In addition, in order to make the life extension possible, it will be necessary to make continuing substantial capital investments. Between now and 2015, the Company projects investing a total of $1.5 billion on: 1) the extended power uprate at Monticello; 2) the extended power uprate at Prairie Island; and 3) the life extension project at Prairie Island, which includes the replacement of the steam generator for Unit 2. It would be premature to recognize the benefits of the life extension prior to the investments being made that make the extension possible.

We are proposing a three-year life extension because that provides roughly half (46 percent) of the financial impact of recognizing the full 20-year life extension. This provides a reasonable balance of reflecting the maximum reasonable amount of benefit of the life extension in advance of the approvals and the investments needed to make that extension a reality. This reduces the pro forma year revenue requirements by:

- Depreciation ($697,000)
- End of Life Nuclear Fuel $136,000
- Nuclear Decommissioning $168,000.

This information also includes the results of an updated nuclear decommissioning study as filed and approved by the Minnesota Commission in Docket No. E-002/M-08-1201. The new decommissioning study parameters, when calculated with a three-year life extension, generate the increase in nuclear decommissioning and end-of-life nuclear fuel presented above.

The Prairie Island life is currently being reviewed as part of the pending Minnesota jurisdiction electric rate case (Docket No. E002/GR-08-1065). The Company will update the Commission of any changes resulting from the Minnesota Commission's final decision.

Q. PLEASE EXPLAIN THE JOINT ZONAL PRICING ADJUSTMENT.

A. Xcel Energy, Great River Energy ("GRE") and Southern Municipal Power Agency ("SMPPA") have transmission facilities that are highly interconnected, and each pays the other based on a combination of usage and investment in their respective "pricing zones." The sharing of costs and revenues occurs through a zonal agreement, which is administered under the MISO tariff. FERC approved GRE's request to revise its MISO Attachment O formula transmission rates from a historical to a forecast year, effective January 1, 2009. In addition to the change in GRE's Attachment O rate, Xcel Energy and GRE are also working towards a Joint Zonal Agreement for Xcel Energy load in the GRE pricing zone that is expected to take effect July 1, 2009. That change increases our joint zonal expenses. Prior to this formal joint zonal agreement the Company paid GRE based off an interim agreement. As of July 1, 2009, the Company would be billed based on GRE's zonal rate. The adjustment(s) results in an increase in revenue requirements of $162,000.

Q. PLEASE EXPLAIN THE EMPLOYEE EXPENSE ADJUSTMENTS.

A. We have included four employee related expense adjustments: 1) Service Company pension; 2) active health care; 3) employee expense allowances; and 4) corrections for mis-recorded social expenses.

Q. WHY ARE YOU REQUESTING AN INCREASE IN SERVICE COMPANY PENSION EXPENSE?

A. As a result of changes in market performance as well as indices, the calculation of benefits costs for pension expense at the Service Company (based on SFAS 87) required key assumptions to be reassessed at December 31, 2008. Because of these market conditions, the discount rate utilized was increased from 6.25 percent to 6.75 percent as a result of changes in the indexed discount rates. As part of this modification, the Company engaged our independent actuaries to prepare a bond matching study in determination of the appropriate discount rate. The actuarial bond matching analysis results validated utilization of the 6.75 percent discount rate. In conjunction with this discount rate change, the Company also reduced its expected long-term rate of return on pension assets from 8.75 percent to 8.50 percent. This change in the long-term investment return rate was driven by lower expected future market returns on our investments. We also adjusted the 2008 return assumption to reflect the decrease in the market value of our investments. These changes increased South Dakota pension expense by $95,000.

Q. PLEASE EXPLAIN WHY ACTIVE HEALTH CARE COSTS HAVE INCREASED SINCE 2008.

A. In 2009, there was a $3,755,000 increase in active health care costs primarily as a result of the combined effects of: (i) an increase in employee census; and (ii) a significant increase in the Company's cost levels per individual. The increase in Company's costs per individual is made up of multiple components, including health care inflation, employee utilization rates, and changes in cost sharing between the Company and the employees on specific procedures or prescription drugs.

Between May 2008 and November 2008, approximately 40 employees were added to NSP-Minnesota Company's employee census. In addition, approximately 89 employees were added to the employee census of Xcel Energy Services, Inc., of which approximately 40 percent of costs are allocated to the Company, resulting in an additional effective census increase of 36 employees. The cost of these additional 76 employees (40 employees, plus 36 employees) has significantly increased the cost estimate for active health care in the 2009 O&M Budget. Approximately $850,000 of the increase is attributable to increased employee census.

Healthcare cost inflation is the rate at which charges by healthcare service providers and medical product providers increase on an annual basis. The increase in healthcare cost inflation reflects a change in the levels of cost control accomplished by the Company for several years prior to 2008. Over the 2005 – 2007 period, we were able to limit medical cost inflation to approximately 3 percent to 4 percent per year through close aggressive negotiations and contract management, even though industry norms reflected medical inflation rates of approximately 8 percent to 9 percent per year during that same period. While we continued to aggressively manage healthcare costs through 2008 and into 2009, we nonetheless experienced an increase in healthcare inflation rates beginning in 2008. We now project that our cost saving efforts have accomplished their goals, but on a going forward basis we are subject to annual increases at an 8 percent level. In other words, the current 8 percent inflation rate appears to be the result of the Company having already used up most of the available alternatives to control health care cost levels.

The third fact affecting our increase in active health care costs is that our work force is aging. As our workforce continues to age, it will tend to increase the number of serious medical conditions, increasing our costs disproportionately per event.

These changes increased South Dakota revenue requirements by $187,000.

Q. WHY HAVE YOU INCLUDED AN ADJUSTMENT REDUCING EMPLOYEE EXPENSES?

A. As part of our response to the current economy, the Company instituted a 20 percent reduction in employee expenses in 2009. While we expect the economy to begin rebounding in 2010, we are leaving in place that 20 percent reduction. That has the effect of reducing the 2008 pro forma year amount by $116,000.

In addition, we have determined there were instances where some social expenses (e.g. athletic tickets) should have been recorded below the line but were not. We have included an adjustment of $19,000 to correct those accounting misclassifications.

Q. PLEASE EXPLAIN WHY THERE IS AN AMORTIZED EXPENSE FOR A PRIVATE SPENT FUEL STORAGE FACILITY.

A. Consistent with the approvals received by the Company in North Dakota, Minnesota, the Company is seeking recovery of the South Dakota share ($169,000) of the Company's total $23 million investment made to develop a privately-owned independent spent fuel storage instillation ("Privately-Owned ISFSI").

Q. PLEASE EXPLAIN THE COMPANY'S EFFORTS TO DEVELOP A PRIVATELY-OWNED ISFSI.

A. When the Company obtained approval for the initial dry storage at Prairie Island, the amount of dry storage that was approved was limited in order to encourage the Company to take all reasonable actions to move spent fuel away from the plants. As a result, the Company developed a three-pronged strategy in its pursuit of alternative storage: (1) active advocacy for Yucca Mountain; (2) a lawsuit against the Department of Energy ("DOE") related to the current lack of permanent repository; and (3) exploration of alternative storage options. In the absence of a federal government permanent repository, the Company concluded that a Privately-Owned ISFSI was key to being able to keep both the Prairie Island and Monticello plants operational through their current license and any renewal.

Q. WHEN DID THE COMPANY BEGIN ITS EFFORTS TO PURSUE A PRIVATELY-OWNED ISFSI?

A. In 1997, together with seven other utilities, NSP formed Private Fuel Storage ("PFS") and submitted a license application to the NRC to site a Privately-Owned ISFSI on a site within the Goshute Indian tribal land in Utah. The NRC approved our request for a license on September 9, 2005.

Q. IF A PRIVATELY-OWNED ISFSI IS DEVELOPED, COULD IT AVOID THE NEED FOR ON-SITE ISFSI AT MONTICELLO AND PRAIRIE ISLAND?

A. No. It is important to recognize that given the significant uncertainty of whether a Privately-Owned ISFSI can actually be developed, it cannot be used to avoid a temporary storage facility at Monticello and Prairie Island. Consequently, any future plans to construct a Privately-Owned ISFSI would be in addition to using the existing Prairie Island and Monticello On-Site ISFSIs.

Q. WHAT IS THE STATUS OF THE LAWSUIT AGAINST THE DOE?

A. The Company has been awarded $116 million by the U.S. Court of Federal Claims in its lawsuit against the U.S. Department of Energy ("DOE") for damages through 2004. The ruling is subject to appeal and no funds have yet been received. A second lawsuit for damages for 2005 through June 2007 has been filed. Thus, the award has no impact on the 2008 pro forma year.

Q. PLEASE EXPLAIN THE RENEWABLE DEVELOPMENT FUND ADJUSTMENT.

A. In order to continue to operate the Prairie Island Nuclear Generating Facility, which required on-site interim nuclear fuel storage, the Company was required to fund the Renewable Development Fund ("RDF"). The total annual funding of the RDF in relation to casks located at our Prairie Island Nuclear Plant is $16 million. As I explained earlier, the Commission's Order in Docket No. EL-04-015 contains the following statement: "Xcel shall accumulate these costs in a separate account, by vintage, from 2004 forward, including carrying charges based upon the rate of return last allowed by this Commission, for the Commission's further consideration in the form of a potentially recoverable regulatory asset." The pro forma year includes $108,000 in RDF expenses, representing the South Dakota allocated share of the energy production ("EP") grant payments and a portion of the RDF administrative costs (prorated based on target funding for energy production grants versus research and development ("R&D") grants in the 3rd RDF Funding Cycle Request for Proposal). The pro forma year does not include expenditures related to R&D and Renewable Energy Production Incentives, which are born directly by Minnesota electric retail customers.

Our pro forma adjustment for RDF expense consists of two parts. The first part of this adjustment is a four-year amortization of the deferred account balance beginning in 2004 of $310,845 or $77,711 per year. The second part of this adjustment represents an ongoing level of recovery for the South Dakota jurisdictional portion of EP grant payments and a portion of the RDF administration costs. As an estimate of this on-going amount, we used the actual amount incurred in 2008 (ending balance as of December 31, 2008 of $310,845 less ending balance as of December 31, 2007 of $280,457) or $30,388. The resulting total of the four-year amortization of the deferred RDF balance and the ongoing annual RDF expense is $108,000.

Q. HAVE FUNDED PARTICIPANTS IN THE RDF BEEN RESTRICTED TO MINNESOTA ENTITIES?

A. No. In fact, one grant has been awarded to a project based in South Dakota and nine grants were awarded to projects based in North Dakota from the RDF out of 70 grants awarded. These ten projects consist of nine R&D grants totaling $7.2 million and one EP grant award of $2 million, which the prospective recipient has since chosen to decline. South Dakota and North Dakota based R&D grants comprise approximately 22 percent of the total R&D grants awarded. Please note, as I stated earlier, that R&D project expenditures are born entirely by Minnesota electric customers, even though the States of South Dakota and North Dakota derive the economic benefit of these projects. Please see Exhibit___ (AEH-1), Schedule 12, for additional detail on grant awards to North and South Dakota based projects.

Q. WHAT ADJUSTMENT DID YOU MAKE WITH RESPECT TO MISO SCHEDULE 24?

A. MISO Schedule 24 expenses are approved for cost recovery through the fuel clause ("FCA") beginning in 2009. Since the 2008 unadjusted test year includes these MISO Schedule 24 expenses, and we do not want to set base rates to recover these costs, therefore, we made an adjustment to remove the MISO Schedule 24 expenses from the pro forma year. The amount of the net expense reduction is $55,000.

Q. WHAT ADJUSTMENT DID YOU MAKE WITH RESPECT TO WHOLESALE MARGINS?

A. Consistent with our most recent South Dakota rate case, the Company's unadjusted test year includes wholesale margins as an offset to the 2008 revenue requirement. Because of the volatility of these margins, we are proposing in this case to instead credit an appropriate level of wholesale margins to the fuel cost revenue requirement paying the margins to the ratepayers through the fuel clause adjustment.

Q WOULD IT BE POSSIBLE TO APPLY A FIXED CREDIT TO BASE RATES IN THIS PROCEEDING?

A. It would be possible, but I do not believe it would be advisable. First, crediting the margins through the FCA is a more accurate method of ensuring that ratepayers receive the appropriate benefit of energy sales from unused generation into the wholesale market. A fixed credit to base rates simply cannot provide the same assurance of appropriate benefit. Since 2005, wholesale margins have averaged approximately $52 million per year (total NSP System). However, there has been wide variation in the actual margins, ranging from $31 million in 2007 to $74 million in 2005. This type of volatility makes it nearly impossible to ensure that ratepayers receive an appropriate level of the benefits if a fixed credit mechanism were used.

Second, a fixed credit mechanism should be based on an accurate cost assignment method for retail and wholesale allocations. If a fixed credit mechanism were adopted, additional work would be required to ensure accurate and transparent cost assignment policies. A detailed design of revisions to cost assignment methods would be necessary to ensure an equitable and accurate outcome. Any significant cost assignment changes will, by definition, alter the potential credit that would likely be applied to base rates. Third, given today's high cost of fuel and purchased power, I believe that the sales should be used to offset some of these costs. This becomes even more evident based on the Company's current plan to add significant wind generation resources onto the system. Due to current and historical cost assignment methods, large swings in wind resource productions create significant fluctuations in the Company's asset based sales. As day-ahead commitments are made on behalf of out native customers, increased real-time wind production exceeding expectations will drive real time energy sales, since all day-ahead purchase commitments are directly assigned to native load. Given the Company's proposal to return asset-based margins to ratepayers through the fuel clause, these increasing swings in wind generation output will not cause ratepayers to bear increased purchased power costs at the expense of wholesale sales. Rather, wind power fluctuations will drive additional real-time sales, but these sales will offset any native cost impacts as the margins are returned to ratepayers through the fuel clause mechanism.

In summary, I recommend returning 100 percent of actual asset-based margins to customers in the FCA. This ensures that ratepayers receive the benefits of the native generation assets and is superior to a fixed credit mechanism. Lastly, the FCA credit addresses the significant uncertainty in wind energy production as additional wind resources are added to our system.

Q. PLEASE DESCRIBE NON-ASSET BASED TRADING.

A. Non-asset based trading is the practice of purchasing energy in the wholesale market over and above our customers' needs and attempting to resell it for a profit. In these transactions, the Company operates as a competitive marketer of wholesale energy, with the potential for economic gains and the risk of losses. Although the introduction of centralized power markets like MISO has increased the types of transactions included in non-asset based trading activities, this basic description still applies. This activity has increased due to the issuance of the Energy Policy Act in 1992, in which FERC began the active promotion of competitive energy markets and began providing market participants with equal access to the transmission grid.

Q. IS THIS MARKET-BASED ACTIVITY REGULATED?

A. Yes. This activity is regulated by the FERC. Although the sale prices are not subjected to significant regulation, the allocation between the operating companies of margins is regulated. The Joint Operating Agreement ("JOA"), a FERC-approved tariff between NSP and the other Xcel Energy utility operating companies, anticipated such trading, defined in that agreement as "Non System Marketing."

Q. PLEASE DESCRIBE THE JOA AND ITS PURPOSE.

A. The JOA was established in 2000 with the completion of the Xcel Energy Inc. merger. Its purpose is to coordinate the trading and resource acquisition activities of the Xcel Energy utility operating companies, including the Company. The JOA ensures that we coordinate these activities, including Non-System Marketing, to the joint benefit of all of the operating companies.

Q. WHAT GUIDANCE DOES THE JOA PROVIDE REGARDING REGULATORY TREATMENT OF MARGINS GENERATED FROM THESE ACTIVITIES?

A. The JOA requires that all margins from such activity -- regardless of which utility operating company executed a specific transaction -- be pooled and allocated among the companies based on the prior year's peak demand. Once this allocation is made, the margins are subject to the applicable regulatory treatment of the relevant state jurisdiction.

Q. WHAT IS THE CURRENT REGULATORY TREATMENT OF THESE NON-ASSET BASED TRANSACTIONS IN THE SOUTH DAKOTA JURISDICTION?

A. There is no specific guidance regarding such transactions, as they were not anticipated at the time of our prior electric rate case. The credit to the retail cost of service adopted in our most recent electric general rate case was based on anticipated asset-based wholesale transactions only. Thus, ratepayers have been unaffected by any gains or losses due to non-asset-based trading activity since the merger.

Q. IS IT APPROPRIATE FOR REGULATED UTILITIES TO ENGAGE IN NON-ASSET BASED TRADING ACTIVITIES?

A. Yes. FERC has for many years promoted competition in wholesale markets. At present, most utilities, including the Company, have FERC-approved market-based sales tariffs that allow them to make wholesale sales at market based rates. Utilities have actively participated in these markets, and have increased such activities as the competitive markets have matured and deepened. The Company also has a compelling interest in full participation in the electric energy trading markets, as failure to do so would cause our customers to incur higher costs through less informed and more costly economic purchase and operational decisions. Less information in a commodity market translates into a risk of the utility paying more for purchases and receiving less for its sales. Thus, this trading activity benefits our customers by generating substantial market price intelligence that is applied to a wide variety of system marketing and operational decisions.

Q CAN NON-ASSET BASED TRADING ACTIVITIES RESULT IN LOSSES AS WELL AS GAINS?

A. Yes. Unlike traditional wholesale margins created from short-term surplus generation sales, non-asset trading can result in both positive wholesale margins and losses. While the Company has never experienced losses from this activity on an aggregate annual basis, losses can and do occur on individual transactions or during shorter-term (e.g. monthly) trading periods.

Q. WHAT REGULATORY TREATMENT OF THIS ACTIVITY DO YOU PROPOSE FOR THIS PROCEEDING?

A. I recommend a sharing mechanism for non-asset trading activity, with a percentage of the net gain flowing to South Dakota retail customers. Like asset-based wholesale margins, the margins created from this activity cannot be forecasted using a production cost model or any other asset-based model, making a forecast of non-asset margins for the South Dakota jurisdiction unreliable. Further, the pooled nature of these margins under the JOA makes it even more difficult to develop a forecast, since the amounts would depend on the activities of all Xcel Energy operating companies. A sharing mechanism would allow the benefit of the margins actually achieved to flow through to customers, while retaining our incentive for active and aggressive participation in this market.

Q. WHAT SPECIFICALLY DO YOU PROPOSE?

A. I propose that South Dakota customers receive 25 percent of the jurisdictional allocation of the margins created by non-asset based transactions, with shareholders retaining the other 75 percent. We would credit the FCA in an amount of 25 percent of annual, actual, non-asset based margins as they are achieved and pooled pursuant to the JOA, similar to the approach I proposed for the asset-based margins. Like that proposal, this approach aligns the interests of our customers and the Company.

Q. WOULD CUSTOMERS BEAR ANY RISKS UNDER YOUR PROPOSAL?

A. No. The Company's proposed sharing mechanism includes ratepayer protection against any net aggregate annual losses. Thus, assuming that non-asset based margins are positive in a calendar year; ratepayers would receive 25 percent of these margins. In the event that net aggregate losses are incurred for the calendar year, the Company would not flow these losses through the FCA, and shareholders would bear all of these losses.

Q. WHY DO YOU PROPOSE THAT CUSTOMERS RECEIVE 25 PERCENT OF NON-ASSET BASED MARGINS COMPARED TO THE 100 PERCENT FOR ASSET-BASED MARGINS?

A. There are three primary reasons. The primary reason is that non-asset based margins are not the outgrowth of utility service. Second, the Company bears all of the risks of non-asset-based activity. This is in stark contrast to asset-based activity, where the costs associated with the assets used to make these sales are embedded in rates, putting our customers at risk to optimize the value derived from these assets. Third, non-asset based margins are created using many of the same resources as asset-based margins. If we were to withdraw from asset based margin activity, there would be very little change in our cost of service. While we have not conducted a formal incremental cost study, it is our belief that 25 percent is greater than the cost savings that would result from terminating this enterprise. As such, a 25 percent sharing is believed to be adequate to cover the incremental cost of this activity while providing additional support toward common costs.

Q. WHAT IS THE NET IMPACT OF THE EXCLUSION OF THE WHOLESALE MARGINS FROM BASE RATES?

A. The net impact is an increase to revenue requirements of $1.8 million. This results from our pro forma adjustment to exclude wholesale margins from the unadjusted test year. This adjustment consists of two parts: an adjustment to exclude the South Dakota jurisdictional portion of asset based margins of $1,775,000 and an adjustment to exclude the South Dakota Jurisdictional portion of non-asset based margins of $35,000, for a total adjustment of $1,810,000.

Q. WITH THESE PRO FORMA CHANGES, IS THE PRO FORMA YEAR AN ACCURATE AND RELIABLE BASIS UPON WHICH TO SET RATES?

A. Yes. With the adjustments I previously described, the pro forma year is a reasonable projection of Company costs and revenues on which to base this request for rate relief.

VI. RATE BASE

Q. IS THE 2008 PRO FORMA RATE BASE, AS ADJUSTED BY THE ABOVE DESCRIBED ADJUSTMENTS, REASONABLE FOR PURPOSES OF DETERMINING FINAL RATES IN THIS PROCEEDING?

A. Yes. The pro forma year rate base was developed on sound ratemaking principles in a manner similar to prior Company electric rate cases. Through the above-described pro forma adjustments it appropriately represents the costs and investments in place at the time rates take affect in 2010.

Q. PLEASE EXPLAIN WHAT RATE BASE REPRESENTS.

A. Rate base primarily reflects the capital expenditures made by a utility to secure plant, equipment, materials, supplies and other assets necessary for the provision of utility service, reduced by amounts recovered from depreciation and non-investor sources of capital.

Q. PLEASE IDENTIFY THE MAJOR COMPONENTS OF THE PRO FORMA YEAR RATE BASE.

A. The pro forma year rate base is generally comprised of the following major items, which will be described in further detail later in my testimony:

- Net Utility Plant;
- Accumulated Deferred Income Taxes; and
- Other Rate Base.

Q. PLEASE DESCRIBE THE SCHEDULES IN YOUR EXHIBIT THAT ARE RELATED TO THE PRO FORMA YEAR AVERAGE INVESTMENT IN RATE BASE.

A. Exhibit ___(AEH-1), Schedule 13 (Rate Base unadjusted test year to pro forma year for both total Company and South Dakota jurisdiction) and Exhibit ___(AEH-1), Schedule 14 (Rate Base comparison for 2006, 2008 unadjusted test year and 2008 pro forma year)

A. Net Utility Plant

Q. WHAT DOES NET UTILITY PLANT REPRESENT?

A. Net utility plant represents the Company's investment in plant and equipment that is used and useful in providing retail electric service to its customers, net of accumulated depreciation and amortization.

Q. PLEASE EXPLAIN THE METHOD USED TO CALCULATE NET UTILITY PLANT INVESTMENT IN THIS CASE.

A. The net utility plant is included in rate base at depreciated original cost reflecting the 13-month average of projected net plant balances. Although the Company used an average of the beginning of year and end of year rate base in its most recent South Dakota electric rate case, Docket No. EL92-016, discussions with Commission staff indicated that a 13-month average is their preferred method of calculating rate base. Therefore, we have used the 13-month average method to develop our unadjusted test year and pro forma year rate base.

Q. WHAT HISTORICAL BASE DID XCEL ENERGY RELY ON AS A STARTING POINT TO DEVELOP THE NET PLANT BALANCES FOR THE PRO FORMA YEAR?

A. The historical base used was Xcel Energy's actual net investment (Plant in Service less Accumulated Depreciation) on the books and records of the Company for the period ending November 30, 2007 through December 31, 2008.

Q. WHAT WAS THE AVERAGE NET UTILITY PLANT INCLUDED IN THE PRO FORMA YEAR RATE BASE?

A. The average net utility plant included in the pro forma year rate base is $321,232,000, as shown on Exhibit___(AEH-1), Schedule 13, Page 1. This is comprised of an average plant balance of $635,320,000 as detailed on Exhibit___(AEH-1), Schedule 13, Page 1, minus an average depreciation reserve of $314,088,000 also shown by component on Exhibit___(AEH-1), Schedule 13, Page 1.

B. Construction Work In Progress

Q. HAS CONSTRUCTION WORK IN PROGRESS ("CWIP") BEEN INCLUDED IN THE PRO FORMA YEAR RATE BASE?

A. No. CWIP is not included in rate base, and there is no corresponding offset of Allowance for Funds Used During Construction ("AFUDC") added to operating income.

C. Accumulated Deferred Income Taxes

Q. PLEASE DESCRIBE ACCUMULATED DEFERRED INCOME TAXES ("ADIT").

A. Inter-period differences exist between the book and taxable income treatment of certain accounting transactions. These differences typically originate in one period and reverse in one or more subsequent periods. For utilities, the largest such timing difference typically is the extent to which accelerated tax depreciation generally exceeds book depreciation during the early years of an asset's service life. ADIT represents the cumulative net deferred tax amounts that have been allowed and recovered in rates in previous periods.

Q. WHY ARE ACCUMULATED DEFERRED INCOME TAXES DEDUCTED IN ARRIVING AT TOTAL RATE BASE?

A. To the extent deferred income taxes have been allowed for recovery in rates, they represent a non-investor source of funds. Accordingly, the average projected ADIT balance is deducted in arriving at total rate base to recognize such funds are available for corporate use between the time they are collected in rates and ultimately remitted to the respective taxing authorities.

Q. WHAT AMOUNT OF ADIT WAS DEDUCTED IN THE PROJECTED PRO FORMA YEAR RATE BASE?

A. As shown on Exhibit___(AEH-1), Schedule 13, Page 1, $55,793,000 was deducted. This amount reflects a 13-month average of pro forma year ADIT balances.

D. Other Rate Base

Q. PLEASE SUMMARIZE THE ITEMS YOU HAVE INCLUDED IN OTHER RATE BASE.

A. Other Rate Base is comprised of primarily what is referred to as Working Capital. It also includes certain unamortized balances that are the result of specific ratemaking amortizations as discussed further in my testimony.

Q. PLEASE EXPLAIN WHAT WORKING CAPITAL REPRESENTS.

A. Working Capital is the average investment in excess of net utility plant provided by investors that is required to provide day-to-day utility service. It includes items such as materials and supplies, fuel inventory, prepayments, and various non-plant assets and liabilities. The net cash requirements, also referred to as Cash Working Capital, is shown separately.

Q. HOW WERE PRO FORMA YEAR MATERIALS AND SUPPLIES AND FUEL INVENTORY REQUIREMENTS CALCULATED?

A. The Materials and Supplies and Fuel Inventory amounts shown on Exhibit___(AEH-1), Schedule 2, Page 2, are based on the 13-month average balances ending November 30, 2007 and December 31, 2008, respectively. The Materials and Supplies average balance included in the pro forma year rate base equals $4,944,000. The pro forma year average rate base amount for Fuel Inventory is $5,879,000.

Q. HOW WERE PRO FORMA YEAR NON-PLANT ASSETS AND LIABILITIES DETERMINED?

A. These balances as shown on Exhibit___(AEH-1), Schedule 2, Page 2, represent the November 30, 2007 to December 31, 2008 actual 13-month average balances. Any book/tax timing differences associated with these items has been reflected in the determination of current and deferred income tax provision and accumulated deferred tax balances previously discussed. This group is primarily comprised of liabilities that reduce pro forma year rate base by $2,637,000.

Q. HOW WERE PRO FORMA YEAR PREPAYMENTS AND OTHER WORKING CAPITAL ITEMS DETERMINED?

A. Items of Prepayments and Other Working Capital, such as customer advances and deposits, are based on the actual 13-month average balances during the period ended December 31, 2008. The net impact of these various items increase pro forma year rate base by $7,149,000 as shown on Exhibit___(AEH-1), Schedule 2, Page 2.

Q. HOW WERE PRO FORMA YEAR CASH WORKING CAPITAL REQUIREMENTS DETERMINED?

A. Cash Working Capital requirements have been determined by applying the results of a comprehensive lead/lag study to the pro forma year revenues and expenses.

Q. PLEASE BRIEFLY EXPLAIN HOW A LEAD/LAG STUDY MEASURES CASH WORKING CAPITAL.

A. A lead/lag study is a detailed analysis of the time periods involved in the utility's receipt and disbursement of funds. The study measures the difference in days between the date services to a customer are rendered and the revenues for that service are received, and the date the costs of rendering the services are incurred until the related disbursements are actually made.

Q. HAS XCEL ENERGY'S LEAD/LAG STUDY BEEN UPDATED SINCE THE LAST SOUTH DAKOTA ELECTRIC RATE CASE (DOCKET NO. EL92-016)?

A. Yes. A lead/lag study was prepared in 2004 for the Company's natural gas operations in conjunction with applications for gas general rate increases that were filed in Minnesota (Docket No. G002/GR-04-1511). The 2004 lead/lag study was expanded to include electric operations and the results were incorporated into the cash working capital calculations included in the Company's 2008 Minnesota electric general rate case (Docket No E002/GR-

08-1065) and its 2007 North Dakota electric general rate case (Case No. PU-400-04-578).

Many components of the lead/lag study associated with electric operations have been updated to reflect current experience. In cases where less significant items were not updated, we used revenue lag day or expense lead day values as filed in the 2008 Minnesota electric rate case. The results of the updated lead/lag study for electric operations were incorporated into the South Dakota jurisdiction cash working capital calculations as shown on Exhibit___(AEH-1), Schedule 2 (COSS, Page 6 of 6). The lead/lag study can be found in Volume 5 of our Application.

Q. WHAT IS THE PRO FORMA YEAR CASH WORKING CAPITAL AMOUNT?

A. The amount included in the average rate base is a positive $1,866,000, as shown on Exhibit___(AEH-1), Schedule 2, (COSS Page 2 of 6). This calculation will need to be revised after the Commission determines the final revenue requirement and rate of return, as these decisions will impact the test-year level of cash working capital.

Q. WHAT IS INDICATED BY THE POSITIVE CASH WORKING CAPITAL AMOUNT?

A. The positive cash working capital indicates overall revenue collections lag the date when the associated costs of service are paid. This means that, on average, cash working capital is being provided by the Company's investors. Accordingly, the positive cash working capital is added to rate base to compensate the Company's investors for funds provided to meet cash working capital requirements.

VII. INCOME STATEMENT

A. Revenues

Q. HAVE YOU CONSIDERED OTHER OPERATING REVENUES AS AN OFFSET TO THE RETAIL REVENUE REQUIREMENT?

A. Yes. The pro forma year includes items such as revenues from transmission-related revenue and specific tariff charges including service activation fees, reconnection fees and others. One other source of revenues comes from billings to NSP-Wisconsin under the Interchange Agreement, which I discuss in more detail below.

B. Operating and Maintenance Expenses

Q. HOW DOES XCEL ENERGY DEVELOP ITS PRO FORMA YEAR PRODUCTION EXPENSE?

A. The major cost in production expense is fuel and purchased energy. The pro forma year expenses are based on unadjusted test year fuel and purchased energy, adjusted for normal weather and fuel recovery timing so that a base cost of fuel and purchased energy is derived that only includes the appropriate South Dakota jurisdictional share of these NSP System costs on a calendar month basis.

Q. PLEASE DESCRIBE THE INTERCHANGE AGREEMENT WITH NSP-WISCONSIN THAT YOU REFERENCED EARLIER.

A. The Company and NSP-Wisconsin operate a single integrated electric generation and transmission system and a single electrical "control area." The integrated system jointly serves the electric customers and loads of the Company and NSP-Wisconsin. However, the specific generators and transmission facilities making up the integrated system are owned by the two separate legal entities, with the ownership boundary at the Minnesota/Wisconsin border. The Interchange Agreement is a FERC approved contractual mechanism that provides a means to share the costs of the integrated system between the two legal entities.

Q. PLEASE DESCRIBE THE COSTS ALLOCATED BETWEEN THE COMPANY AND NSP-WISCONSIN UNDER THE INTERCHANGE AGREEMENT.

A. Under the Interchange Agreement, the Company and NSP-Wisconsin share annual system generation (production) and transmission costs. Under the Interchange Agreement formulas, approximately 16 percent of the costs of the Company system are allocated to NSP-Wisconsin, and approximately 84 percent of the NSP-Wisconsin system costs are allocated to the Company, because approximately 84 percent of the load on the integrated system is the Company load and 16 percent is NSP-Wisconsin load. The exact allocation percentages are determined by the allocation factors updated and filed at FERC annually. The Interchange Agreement also provides for an allocation of revenues received by the Company and NSP-Wisconsin, such as revenues from off-system wholesale sales.

The 2008 unadjusted test year Interchange Revenue and Interchange Expenses have been calculated using 2008 Company and NSP-Wisconsin actual information. This is consistent with the treatment of Interchange Revenues and Interchange Expenses in the Company's 1991 unadjusted test year in Docket No. EL92-016.

Q. TO WHAT FERC ACCOUNTS ARE INTERCHANGE REVENUE AND INTERCHANGE EXPENSES RECORDED?

A. Interchange Agreement revenues related to fixed and variable production as well as transmission system costs are recorded to FERC Account 456 – Other Electric Revenues. Interchange Agreement expense (billings from NSP-Wisconsin to the Company) are recorded to the following FERC Accounts:

Interchange Agreement Cost	**FERC Account and Description**
Fixed Production	557 – Other Power Supply Expenses-Other
Variable Production	557 – Other Power Supply Expenses-Other
Transmission	566 – Miscellaneous Transmission Expenses

Workpapers supporting the calculation for Interchange Agreement revenues (billings from the Company to NSP-Wisconsin) can be found in Volume 4, Section R1, Tab - Interchange Agreement. Workpapers supporting the calculation of Interchange Agreement expenses (billings from NSP-Wisconsin to the Company) can be found in Volume 4, Section O1, Tab - Interchange Agreement.

C. Depreciation Expense

Q. WHAT IS THE BASIS OF THE DEPRECIATION RATES AND EXPENSE USED IN THIS PROCEEDING?

A. Depreciation expense for the pro forma year reflects the depreciation rates last certified by the Minnesota Commission, and is consistent with the ongoing practice followed by the Company, with the Commission's approval, in South Dakota rate case proceedings.

Q. ARE THERE OTHER ASPECTS OF THE INCOME STATEMENT DEVELOPMENT THAT YOU WISH TO ADDRESS?

A. Yes. I will address the effect of the Job Creation Act of 2004 ("the Act").

Q. WHAT EFFECT DID THE ACT HAVE ON THE DEVELOPMENT OF THE TEST-YEAR INCOME STATEMENT?

A. This Act provides for a production tax deduction on the income based on federal taxable income generated from the production portion of the Company. In order to reflect this deduction in the determination of the cost of service, I calculated our total income based on the amount of the revenue deficiency, and allocated the appropriate percent to production as income (based on a functional separation of overall revenue requirements) using our proposed capital structure and 11.25 percent ROE. In the unadjusted test year, the deduction is valued at $69,000, resulting in an increase of $37,000 in revenue requirements. In the pro forma year, production taxable income is negative, and therefore no deduction is taken. Earlier in my testimony I discuss the adjustment to the production tax deduction of $69,000 to reflect the impact of the pro forma adjustments. This calculation will need to be revised after the Commission determines the final revenue requirement and rate of return, as these decisions will impact the test-year level of production income. The tax deduction is incorporated into the cost of service income tax determination and is shown on Exhibit___(AEH-1), Schedule 7b (income statement bridge schedule) as an adjustment.

VIII. CONCLUSION

Q. CAN YOU SUMMARIZE YOUR RECOMMENDATION TO THE COMMISSION?

A. I recommend that the Commission determine an overall retail revenue requirement of $164,967,000 and revenue deficiency of $18,583,000 for the

Company's South Dakota jurisdictional electric operation, determined by the cost of service for the 2008 unadjusted test year adjusted to reflect those pro forma adjustments needed to make the pro forma year representative of the conditions facing the Company when it implements final rates in 2010.

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

A. Yes, it does.

Northern States Power Company, a Minnesota corporation
Electric Utility – State of South Dakota
Resume of Anne E. Heuer

Manager
Revenue Analysis

Xcel Energy Services Inc.
414 Nicollet Mall
Minneapolis, MN 55401

Current Responsibilities

Since January 2007, I have been the manager of Revenue Analysis. In this position, I am responsible for the general administration of the Revenue Analysis area and for the preparation and presentation of cost of service studies, revenue requirement determinations and jurisdictional annual reports for the electric and gas rates filed on behalf of Northern States Power Company, a Minnesota corporation, with the Minnesota Public Utilities Commission, the North Dakota Public Service Commission, the South Dakota Public Utilities Commission and the Federal Energy Regulatory Commission.

Previous Employment (1975 to 2007)

Rate Consultant – Xcel Energy Services Inc.
Manager, Regulatory Development - NSP
Principal Rate Analyst – NSP
Senior Electric Financial Analyst – Electric Finance – NSP
Senior Budget Analyst – Financial Accounting - NSP
Senior Systems Cost Analyst – Information Services - NSP

Education

Augsburg College, Minneapolis, Minnesota
Bachelor of Arts – Business Administration - Finance
December 1985

Current Testimony

North Dakota - Overall Revenue Requirements, Rate Base, Income Statement, Case No. PU 07-776, 2007
Minnesota - Overall Revenue Requirements, Rate Base, Income Statement, Docket No. E002/GR-08-1065, 2008

ROE = 2.98%
Deficiency = $18,583
% Increase = 12.69%
Required ROE = 11.25%

Northern States Power Company, a Minnesota corporation
Electric Utility - South Dakota Retail Jurisdiction
Cost of Service Study
2008 Pro Forma

Summary Reports

June 30, 2009

(Dollars in Thousands)

Rate Base Summary

		Total Company Electric			South Dakota Retail Electric			All Other		
		Beginning Balance	Ending Balance	Average Balance	Beginning Balance	Ending Balance	Average Balance	Beginning Balance	Ending Balance	Average Balance
1	Plant Investment	11,700,141	11,700,141	11,700,141	635,320	635,320	635,320	11,064,821	11,064,821	11,064,821
2	Depreciation Reserve	(5,891,292)	(5,891,292)	(5,891,292)	(314,088)	(314,088)	(314,088)	(5,577,204)	(5,577,204)	(5,577,204)
3	Net Utility Plant	5,808,849	5,808,849	5,808,849	321,232	321,232	321,232	5,487,617	5,487,617	5,487,617
4	C.W.I.P.	0	0	0	0	0	0	0	0	0
5	Accumulated Deferred Taxes	(958,947)	(958,947)	(958,947)	(55,793)	(55,793)	(55,793)	(903,154)	(903,154)	(903,154)
	Other Rate Base:									
6	Cash Working Capital	29,812	29,812	29,812	1,866	1,866	1,866	27,947	27,947	27,947
7	Materials & Supplies	94,856	94,856	94,856	4,944	4,944	4,944	89,912	89,912	89,912
8	Fuel Inventory	111,084	111,084	111,084	5,879	5,879	5,879	105,205	105,205	105,205
9	Non-Plant Assets & Liab	(48,905)	(48,905)	(48,905)	(2,637)	(2,637)	(2,637)	(46,268)	(46,268)	(46,268)
10	Prepaids & Other	61,262	61,262	61,262	7,149	7,149	7,149	54,113	54,113	54,113
11	**Total Rate Base**	**5,098,011**	**5,098,011**	**5,098,011**	**282,640**	**282,640**	**282,640**	**4,815,372**	**4,815,372**	**4,815,372**

(Dollars in Thousands)

Income Statement Summary

		Total Company Electric	South Dakota Retail Electric	All Other
	Operating Revenues			
1	Retail	2,906,779	146,384	2,760,395
2	CIP Adjustment to Program Costs	0	-	0
3	Interdepartmental	564	-	564
4	Other Operating	743,947	34,933	709,014
5	Gross Earnings Tax	0	-	0
6	**Total Operating Revenues**	**3,651,290**	**181,317**	**3,469,973**
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	1,470,130	74,867	1,395,263
8	Power Production	634,321	32,794	601,527
9	Transmission	155,646	7,988	147,658
10	Distribution	105,630	6,045	99,585
11	Customer Accounting	65,189	4,244	60,945
12	Customer Service & Information	60,895	332	60,563
13	Sales, Econ Dvlp & Other	391	103	288
14	Administrative & General	193,942	10,864	183,078
15	Total Operating Expenses	2,686,144	137,237	2,548,907
16	Depreciation	381,954	21,470	360,484
17	Amortization	12,106	352	11,754
	Taxes:			
18	Property	106,720	4,956	101,764
19	Gross Earnings	0	-	0
20	Deferred Income Tax & ITC	114,362	4,819	109,543
21	State & Federal Income (see Page 3)	(4,900)	(2,384)	(2,516)
22	Payroll & Other	27,154	1,452	25,702
23	Total Taxes	243,336	8,843	234,493
24	**Total Expenses**	**3,323,540**	**167,902**	**3,155,638**
25	AFUDC	0	-	0
26	**Total Operating Income**	**327,750**	**13,415**	**314,335**

Northern States Power Company, a Minnesota corporation
Electric Utility - South Dakota Retail Jurisdiction
Cost of Service Study
2008 Pro Forma
(Dollars in Thousands)

Income Tax Summary

		Total Company Electric	SD Retail Electric	All Other
	Income Before Taxes			
1	Total Operating Revenues	3,651,290	181,317	3,469,973
2	less: Total Operating Expenses	(2,686,144)	(137,237)	(2,548,907)
3	Book Depreciation & Amortization	(394,060)	(21,822)	(372,238)
4	Taxes (Other Than Current Income)	(248,236)	(11,227)	(237,009)
5	**Total Before Tax Book Income**	**322,850**	**11,031**	**311,819**
	Tax Additions			
6	Book Depreciation	381,954	21,470	360,484
7	Deferred Income Taxes & ITC	114,362	4,819	109,543
8	Nuclear Fuel Burn (ex D&D)	79,775	4,095	75,680
9	Nuclear Outage Accounting	43,739	2,242	41,497
10	Avoided Tax Interest	52,295	2,707	49,588
11	Confiruration Mgmt	57	57	0
12	TBT Production	(9)	0	(9)
13	TBT Transmission	(3)	0	(3)
14	TBT Distribution	(6)	0	(6)
15	Open Line	0	0	0
16	Other Book Additions	0	0	0
17	**Total Tax Additions**	**672,164**	**35,390**	**636,774**
	Tax Deductions			
18	Debt Interest Expense	163,646	9,073	154,573
19	Tax Depreciation & Removal	840,635	44,018	796,617
20	Manufacture Production Deduction	0	0	0
21	Meal & Fas 106	2,093	112	1,981
22	Open	0	0	0
23	Open	0	0	0
24	Other Tax/Book Timing Differences	(24,075)	(1,399)	(22,676)
25	Net Preferred Stock Deduction	0	0	0
26	**Total Tax Deductions**	**982,299**	**51,804**	**930,495**
27	**State Taxable Income**	**12,715**	**(5,383)**	**18,097**
28	State Income Tax Rate	9.00%	0.00%	N/A
29	State Taxes before Credits	1,144	0	1,144
30	State Credits	593	0	593
31	**Total State Income Taxes**	**551**	**0**	**551**
32	**Federal Taxable Income**	**12,164**	**(5,383)**	**17,546**
33	Federal Income Tax Rate	35.00%	35.00%	35.00%
34	Federal Tax before Credits	4,257	(1,884)	6,141
35	Federal Tax Credits	9,708	500	0
36	**Total Federal Income Taxes**	**(5,451)**	**(2,384)**	**6,141**
37	**Total Federal & State Income Taxes**	(4,900)	(2,384)	6,692

Revenue Requirement & Return Summary

(Dollars in Thousands)

	Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt	6.6400%	48.3700%	3.2100%
2	Short Term Debt	0.0000%	0.0000%	0.0000%
3	Preferred Stock	0.0000%	0.0000%	0.0000%
4	Common Equity	11.2500%	51.6300%	5.8100%
5	**Required Rate of Return**			**9.0200%**

Composite Income Tax Rates		
State of South Dakota Tax rate		0.00%
Federal Statutory Tax rate	35.00%	
Federal Effective Tax Rate (1-State Rate * Fed Rate)		35.00%
Total South Dakota Composite Tax Rate		**35.00%**
Total Corporate Composite Tax Rate		**40.85%**

		Total Company Electric	SD Retail Electric	All Other
	Rate of Return (ROR)			
6	Total Operating Income	327,750	13,415	314,335
7	Total Average Rate Base	5,098,011	282,640	4,815,372
8	**ROR** (Operating Income / Rate Base)	**6.43%**	**4.75%**	**6.53%**
	Return on Equity (ROE)			
9	Total Operating Income	327,750	13,415	314,335
10	Debt Interest (Rate Base * Weighted Debt Cost)	(163,646)	(9,073)	(154,573)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	164,104	4,342	159,761
13	Equity Rate Base (Rate Base * Equity Ratio)	2,632,103	145,927	2,486,176
14	**ROE** (Earnings for Common / Equity Rate Base)	**6.23%**	**2.98%**	**6.43%**
	Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Return)	459,841	25,494	434,347
16	Operating Income	327,750	13,415	314,335
17	Operating Income Deficiency	132,091	12,079	120,012
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.69056	1.53846	N/A
19	**Revenue Deficiency** (Income Deficiency * Conversion Factor)	**223,308**	**18,583**	**204,725**
	Total Retail Revenue Requirements			
20	Retail Related Revenues	2,907,343	146,384	2,760,959
21	Revenue Deficiency	223,308	18,583	204,725
22	**Total Retail Revenue Requirements**	**3,130,651**	**164,967**	**2,965,684**
23	**Percentage Increase (Decrease)**	**7.68%**	**12.69%**	**7.41%**

(Dollars in Thousands)

Rate Base Detail - Cash Working Capital

Line	Item		Lead Days	Total Company Electric Dollars	Total Company Electric Dollar x Days		South Dakota Retail Electric Dollars	South Dakota Retail Electric Dollar x Days		All Other Dollars	All Other Dollar x Days
	Expenses										
	Includable Expenses		**Lead Days**	**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**
	Fuel Expenses										
1	Coal & Rail Transport		21.08	356,593	7,515,911		18,874	397,807		337,719	7,118,103
2	Gas for Generation		38.45	101,778	3,912,957		5,387	207,109		96,391	3,705,848
3	Oil		22.51	5,023	113,043		266	5,986		4,757	107,056
4	Nuclear & EOL		0.00	76,907	0		4,218	0		72,689	0
5	Nuclear Disposal		76.00	12,549	953,724		644	48,944		11,905	904,780
6				552,850	12,495,634		29,389	659,846		523,461	11,835,788
	Purchased Power										
7	Purchases		28.12	1,102,305	30,992,407		56,808	1,597,214		1,045,497	29,395,194
8	Interchange		38.21	106,362	4,064,092		5,498	210,079		100,864	3,854,013
				1,208,667	35,056,499		62,306	1,807,292		1,146,361	33,249,207
	Labor & Related Costs										
9	Regular Payroll		12.31	352,911	4,344,334		18,336	225,716		334,575	4,118,618
10	Incentive Compensation		255.05	(9,738)	(2,483,677)		(212)	(54,071)		(9,526)	(2,429,606)
11	Pension & Benefits		19.20	54,624	1,048,781		2,968	56,986		51,656	991,795
12	Subtotal Labor & Related			397,797	2,909,438		21,092	228,631		376,705	2,680,807
13											
14	All Other Operating Expenses		35.01	526,830	18,442,749		24,450	855,927		502,380	17,586,822
15	Property Tax		356.72	106,720	38,069,158		4,956	1,767,904		101,764	36,301,254
16	Employer's Payroll Taxes		26.56	27,154	721,210		1,452	38,565		25,702	682,645
17	Gross Earnings Tax		51.98	0	0		0	0		0	0
18	Federal Income Tax		37.75	(5,451)	(205,766)		(2,384)	(89,996)		(3,067)	(115,769)
19	State Income Tax		37.75	551	20,798		0	0		551	20,798
20	State Sales Tax Customer Billings		35.73	125,632	4,488,831		5,320	190,084		120,312	4,298,748
21	Total Expenses		38.09	2,940,750	111,998,553	37.24	146,581	5,458,253	38.13	2,794,169	106,540,300
22	**Net Annual Expense Amount**				306,845			14,954			291,891
	Revenues		**Lag Days**	**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**
23	Computer Billing	100.00%	42.83	2,906,779	124,492,403		146,879	6,290,578		2,759,900	118,201,825
24	Hand Billed	0.00%	42.83	0	0		0	0		0	0
25	Retail Revenue Adjustments		0.00	0	0		0	0		0	0
26	Interdepartmental		0.00	564	0		0	0		564	0
27	Late Payment		0.00	5,644	0		354	0		5,290	0
28	Connect and Trouble Charges		42.83	1,931	82,701		227	9,722		1,704	72,979
29	CIP Incentive		0.00	0	0		0	0		0	0
30	Rentals		114.17	4,128	471,294		241	27,515		3,887	443,779
31	Interchange Revenues		38.21	380,382	14,534,396		19,857	758,736		360,525	13,775,660
32	Sales for Resale		37.10	251,774	9,340,815		8,712	323,215		243,062	9,017,600
33	Production Associated Revenues		37.10	5,759	213,659		305	11,316		5,454	202,343
34	MISO		14.00	7,178	100,492		368	5,152		6,810	95,340
35	Point to Point Firm		37.10	49,882	1,850,622		2,561	95,013		47,321	1,755,609
36	Services & Facilities		37.10	8,611	319,468		438	16,250		8,173	303,218
37	Ancillary		37.10	14,033	520,624		720	26,712		13,313	493,912
38	Distribution Associated Revenues		42.83	476	20,386		0	0		476	20,386
39	Other		42.83	17,171	735,405		1,310	56,105		15,861	679,300
40	JOA - Rev fr/to PSC		37.10	(3,022)	(112,116)		(160)	(5,936)		(2,862)	(106,180)
41	(blank)		0.00	0	0		0	0		0	0
42	(blank)		0.00	0	0		0	0		0	0
43	(blank)		0.00	0	0		0	0		0	0
44	Total Revenues		41.79	3,651,290	152,570,150	41.88	181,812	7,614,378	41.78	3,469,478	144,955,773
45	Net Annual Amount				418,000			20,861			397,139
46	Expense / Revenue Factor				0.80540042			0.806223735			
47	**Allocated Revenue Amount**				336,658			16,819			
48	**Net Cash Working Capital**		Page 1 - Line 6		29,812			1,865			27,948

ROE = 7.54%
Deficiency = $7,095
% Increase = 4.83%
Required ROE = 11.25%

Northern States Power Company (MN)
Electric Utility - South Dakota Retail Jurisdiction
Cost of Service Study
2008 Actual/Baseline

Summary Reports

June 30, 2009

(Dollars in Thousands)

Rate Base Summary

		Total Company Electric			South Dakota Retail Electric			All Other		
		Beginning Balance	Ending Balance	Average Balance	Beginning Balance	Ending Balance	Average Balance	Beginning Balance	Ending Balance	Average Balance
1	Plant Investment	10,954,477	10,954,477	10,954,477	589,212	589,212	589,212	10,365,265	10,365,265	10,365,265
2	Depreciation Reserve	(5,861,819)	(5,861,819)	(5,861,819)	(312,270)	(312,270)	(312,270)	(5,549,549)	(5,549,549)	(5,549,549)
3	Net Utility Plant	5,092,658	5,092,658	5,092,658	276,942	276,942	276,942	4,815,716	4,815,716	4,815,716
4	C.W.I.P.	0	0	0	0	0	0	0	0	0
5	Accumulated Deferred Taxes	(855,388)	(855,388)	(855,388)	(49,023)	(49,023)	(49,023)	(806,365)	(806,365)	(806,365)
	Other Rate Base:									
6	Cash Working Capital	36,870	36,870	36,870	2,279	2,279	2,279	34,591	34,591	34,591
7	Materials & Supplies	94,856	94,856	94,856	4,944	4,944	4,944	89,912	89,912	89,912
8	Fuel Inventory	111,084	111,084	111,084	5,879	5,879	5,879	105,205	105,205	105,205
9	Non-Plant Assets & Liab	(121,267)	(121,267)	(121,267)	(6,518)	(6,518)	(6,518)	(114,749)	(114,749)	(114,749)
10	Prepaids & Other	43,306	43,306	43,306	6,148	6,148	6,148	37,158	37,158	37,158
11	**Total Rate Base**	**4,402,119**	**4,402,119**	**4,402,119**	**240,651**	**240,651**	**240,651**	**4,161,468**	**4,161,468**	**4,161,468**

(Dollars in Thousands)

Income Statement Summary

		Total Company Electric	South Dakota Retail Electric	All Other
	Operating Revenues			
1	Retail	2,907,274	146,879	2,760,395
2	CIP Adjustment to Program Costs	0	-	0
3	Interdepartmental	564	-	564
4	Other Operating	742,763	36,505	706,258
5	Gross Earnings Tax	0	-	0
6	**Total Operating Revenues**	**3,650,601**	**183,384**	**3,467,217**
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	1,477,787	76,263	1,401,524
8	Power Production	588,245	30,517	557,728
9	Transmission	147,078	7,551	139,527
10	Distribution	102,935	5,917	97,018
11	Customer Accounting	64,638	4,212	60,426
12	Customer Service & Information	60,978	415	60,563
13	Sales, Econ Dvlp & Other	152	3	149
14	Administrative & General	181,541	9,917	171,624
15	Total Operating Expenses	2,623,354	134,795	2,488,559
16	Depreciation	364,094	20,214	343,880
17	Amortization	11,758	4	11,754
	Taxes:			
18	Property	97,785	4,436	93,349
19	Gross Earnings	0	-	0
20	Deferred Income Tax & ITC	113,218	5,119	108,099
21	State & Federal Income (see Page 3)	45,940	340	45,599
22	Payroll & Other	25,697	1,381	24,316
23	Total Taxes	282,640	11,276	271,363
24	**Total Expenses**	**3,281,846**	**166,289**	**3,115,556**
25	AFUDC	0	-	0
26	**Total Operating Income**	**368,755**	**17,095**	**351,661**

(Dollars in Thousands)

Income Tax Summary

		Total Company Electric	SD Retail Electric	All Other
	Income Before Taxes			
1	Total Operating Revenues	3,650,601	183,384	3,467,217
2	less: Total Operating Expenses	(2,623,354)	(134,795)	(2,488,559)
3	Book Depreciation & Amortization	(375,852)	(20,218)	(355,634)
4	Taxes (Other Than Current Income)	(236,700)	(10,936)	(225,764)
5	**Total Before Tax Book Income**	**414,695**	**17,435**	**397,260**
	Tax Additions			
6	Book Depreciation	364,094	20,214	343,880
7	Deferred Income Taxes & ITC	113,218	5,119	108,099
8	Nuclear Fuel Burn (ex D&D)	76,752	3,940	72,812
9	Nuclear Outage Accounting	13,174	675	12,499
10	Avoided Tax Interest	43,578	2,267	41,311
11	Confiruration Mgmt	0	0	0
12	TBT Production	(9)	0	(9)
13	TBT Transmission	(3)	0	(3)
14	TBT Distribution	(6)	0	(6)
15	Open Line	0	0	0
16	Other Book Additions	0	0	0
17	**Total Tax Additions**	**610,798**	**32,215**	**578,583**
	Tax Deductions			
18	Debt Interest Expense	141,308	7,725	133,583
19	Tax Depreciation & Removal	783,849	41,694	742,155
20	Manufacture Production Deduction	1,154	69	1,085
21	Meal & Fas 106	2,093	112	1,981
22	Open	0	0	0
23	Open	0	0	0
24	Other Tax/Book Timing Differences	(25,370)	(1,468)	(23,902)
25	Net Preferred Stock Deduction	0	0	0
26	**Total Tax Deductions**	**903,034**	**48,132**	**854,902**
27	**State Taxable Income**	**122,459**	**1,518**	**120,941**
28	State Income Tax Rate	9.00%	0.00%	N/A
29	State Taxes before Credits	11,018	0	11,018
30	State Credits	593	0	593
31	**Total State Income Taxes**	**10,425**	**0**	**10,425**
32	**Federal Taxable Income**	**112,034**	**1,518**	**110,516**
33	Federal Income Tax Rate	35.00%	35.00%	35.00%
34	Federal Tax before Credits	39,212	531	38,681
35	Federal Tax Credits	3,697	191	0
36	**Total Federal Income Taxes**	**35,515**	**340**	**38,681**
37	**Total Federal & State Income Taxes**	45,940	340	49,105

Northern States Power Company, a Minnesota corporation
Electric Utility - South Dakota Retail Jurisdiction
Cost of Service Study
2008 Actual/Baseline

Docket No. EL-09____
Exhibit___(AEH-1) Schedule 2A

Revenue Requirement & Return Summary

(Dollars in Thousands)

	Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt	6.6400%	48.3700%	3.2100%
2	Short Term Debt	0.0000%	0.0000%	0.0000%
3	Preferred Stock	0.0000%	0.0000%	0.0000%
4	Common Equity	11.2500%	51.6300%	5.8100%
5	**Required Rate of Return**			**9.0200%**

Composite Income Tax Rates		
State of South Dakota Tax rate		0.00%
Federal Statutory Tax rate	35.00%	
Federal Effective Tax Rate (1-State Rate * Fed Rate)		35.00%
Total South Dakota Composite Tax Rate		**35.00%**
Total Corporate Composite Tax Rate		**40.85%**

		Total Company Electric	SD Retail Electric	All Other
	Rate of Return (ROR)			
6	Total Operating Income	368,755	17,095	351,661
7	Total Average Rate Base	4,402,119	240,651	4,161,468
8	**ROR** (Operating Income / Rate Base)	**8.38%**	**7.10%**	**8.45%**
	Return on Equity (ROE)			
9	Total Operating Income	368,755	17,095	351,661
10	Debt Interest (Rate Base * Weighted Debt Cost)	(141,308)	(7,725)	(133,583)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	227,447	9,370	218,077
13	Equity Rate Base (Rate Base * Equity Ratio)	2,272,814	124,248	2,148,566
14	**ROE** (Earnings for Common / Equity Rate Base)	**10.01%**	**7.54%**	**10.15%**
	Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Return)	397,071	21,707	375,364
16	Operating Income	368,755	17,095	351,661
17	Operating Income Deficiency	28,316	4,612	23,704
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.69056	1.53846	N/A
19	**Revenue Deficiency** (Income Deficiency * Conversion Factor)	**47,870**	**7,095**	**40,775**
	Total Retail Revenue Requirements			
20	Retail Related Revenues	2,907,838	146,879	2,760,959
21	Revenue Deficiency	47,870	7,095	40,775
22	**Total Retail Revenue Requirements**	**2,955,708**	**153,974**	**2,801,734**
23	**Percentage Increase (Decrease)**	**1.65%**	**4.83%**	**1.48%**

(Dollars in Thousands)

Rate Base Detail - Cash Working Capital

				Total Company Electric			South Dakota Retail Electric			All Other	
	Expenses										
	Includable Expenses		**Lead Days**	**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**
	Fuel Expenses										
1	Coal & Rail Transport		21.08	356,593	7,515,911		18,874	397,807		337,719	7,118,103
2	Gas for Generation		38.45	101,778	3,912,957		5,387	207,109		96,391	3,705,848
3	Oil		22.51	5,023	113,043		266	5,986		4,757	107,056
4	Nuclear & EOL		0.00	76,907	0		4,218	0		72,689	0
5	Nuclear Disposal		76.00	12,549	953,724		644	48,944		11,905	904,780
6				552,850	12,495,634		29,389	659,846		523,461	11,835,788
	Purchased Power										
7	Purchases		28.12	1,102,305	30,992,407		56,808	1,597,214		1,045,497	29,395,194
8	Interchange		38.21	106,362	4,064,092		5,498	210,079		100,864	3,854,013
				1,208,667	35,056,499		62,306	1,807,292		1,146,361	33,249,207
	Labor & Related Costs										
9	Regular Payroll		12.31	352,911	4,344,334		18,336	225,716		334,575	4,118,618
10	Incentive Compensation		255.05	(9,738)	(2,483,677)		(212)	(54,071)		(9,526)	(2,429,606)
11	Pension & Benefits		19.20	54,624	1,048,781		2,968	56,986		51,656	991,795
12	Subtotal Labor & Related			397,797	2,909,438		21,092	228,631		376,705	2,680,807
13											
14	All Other Operating Expenses		35.01	464,040	16,244,648		22,008	770,434		442,032	15,474,214
15	Property Tax		356.72	97,785	34,881,865		4,436	1,582,410		93,349	33,299,455
16	Employer's Payroll Taxes		26.56	25,697	682,512		1,381	36,679		24,316	645,833
17	Gross Earnings Tax		51.98	0	0		0	0		0	0
18	Federal Income Tax		37.75	35,515	1,340,691		340	12,848		35,175	1,327,843
19	State Income Tax		37.75	10,425	393,533		0	0		10,425	393,533
20	State Sales Tax Customer Billings		35.73	125,632	4,488,831		5,320	190,084		120,312	4,298,748
21	Total Expenses		37.18	2,918,408	108,493,653	36.15	146,272	5,288,224	37.23	2,772,135	103,205,429
22	**Net Annual Expense Amount**				297,243			14,488			282,755
	Revenues		**Lag Days**	**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**
23	Computer Billing	100.00%	42.83	2,907,274	124,513,603		146,879	6,290,578		2,760,395	118,223,025
24	Hand Billed	0.00%	42.83	0	0		0	0		0	0
25	Retail Revenue Adjustments		0.00	0	0		0	0		0	0
26	Interdepartmental		0.00	564	0		0	0		564	0
27	Late Payment		0.00	5,644	0		354	0		5,290	0
28	Connect and Trouble Charges		42.83	1,931	82,701		227	9,722		1,704	72,979
29	CIP Incentive		0.00	0	0		0	0		0	0
30	Rentals		114.17	4,128	471,294		241	27,515		3,887	443,779
31	Interchange Revenues		38.21	380,382	14,534,396		19,857	758,736		360,525	13,775,660
32	Sales for Resale		37.10	255,234	9,469,181		10,522	390,366		244,712	9,078,815
33	Production Associated Revenues		37.10	5,759	213,659		305	11,316		5,454	202,343
34	MISO		14.00	7,178	100,492		368	5,152		6,810	95,340
35	Point to Point Firm		37.10	45,238	1,678,330		2,323	86,183		42,915	1,592,147
36	Services & Facilities		37.10	8,611	319,468		438	16,250		8,173	303,218
37	Ancillary		37.10	14,033	520,624		720	26,712		13,313	493,912
38	Distribution Associated Revenues		42.83	476	20,386		0	0		476	20,386
39	Other		42.83	17,171	735,405		1,310	56,105		15,861	679,300
40	JOA - Rev fr/to PSC		37.10	(3,022)	(112,116)		(160)	(5,936)		(2,862)	(106,180)
41	(blank)		0.00	0	0		0	0		0	0
42	(blank)		0.00	0	0		0	0		0	0
43	(blank)		0.00	0	0		0	0		0	0
44	Total Revenues		41.79	3,650,601	152,547,424	41.84	183,384	7,672,699	41.78	3,467,217	144,874,725
45	Net Annual Amount				417,938			21,021			396,917
46	Expense / Revenue Factor				0.799432124			0.797628667			
47	**Allocated Revenue Amount**				334,113			16,767			
48	**Net Cash Working Capital**		**Page 1 - Line 6**		36,870			2,279			34,592

($000's)

Line	of the Revenue Deficiency	Revenue Deficiency (millions)
1	Capital Recovery: for additional rate base investment (includes return requirement, change in capital structure, cost of capital and depreciation)	$15.8
	Operating Expenses (including reclasses shown on page 2):	
2	Power Production	$3.2
3	Transmission	$1.5
4	Distribution	$0.0
5	Customer Accounts	$0.2
6	Customer Info Services, Sales & Ecnomic Developm	$0.1
7	Administrative and General Expense	$1.4
8	Total Operating Expenses	$6.4
9	Payroll Taxes	$0.4
10	Amortizations	$0.0
11	Subtotal	$22.6
12	Less, Net Sales and Growth in Margin (including reclasses)	($1.2)
13	Net Change in Revenue Deficiency	$21.4
14	2006 Revenue Deficiency/(Sufficiency)	($2.8)

Summary of Test Year O & M Expense Changes
Since Docket No. E002/GR-05-1428
Shown by Functional Grouping, Gross Dollar Change Over
Three Year Interval Since the 2006 Test Year
(dollars in thousands)

Line	Functional Class	Increase (Decrease)
1	Power Production	$3,393
	Reclass Def Elec Energy Cost to Margin	($673)
	Reclass of WI IA Variable Costs to Margin	$1,219
	Reclass of MISO Sched 16&17 to Margin	($173)
	Reclass Fuel Handling from Margin	$167
	Reclass true-up of Wi Fuel from Margin	$50
	Reclass of MISO Auction rights from Margin	($216)
	Reclass of Windsource from Margin	($70)
	Net Power Production	$3,698
	Interchange Impact	($569)
	Net Power Production after Interchange	$3,129
2	Transmission Operating and Maintenance	$2,227
	Reclass MISO Network Deliveries to Margin	($415)
	Net Transmission Operating and Maintenance	$1,812
	Interchange Impact	($284)
	Net Transmission after Interchange	$1,528
3	Distribution and Maintenance Expense	$17
4	Customer Accounting	$184
5	Customer Services and Sales Expenses	$146
6	Administrative and General Expenses	$1,391
7	Payroll Taxes	$420
8	Total Change In Operating Expenses	$6,815

Northern States Power Company, a Minnesota corporation — Docket No. EL09-______
Electric Utility - State of South Dakota — Exhibit___(AEH-1), Schedule 4
OPERATING REVENUES, OPERATING EXPENSE, — Page 1 of 2
TOTAL AVAILABLE FOR RETURN WITH PRESENT AND FINAL RATES
2008 Pro Forma
(Dollars in Thousands)

Line No.	Description	2008 Pro Forma Present Rates (A)	Final Increase (B)	2008 Pro Forma Final Rates (C) = (B) + (A)
	Operating Revenues			
1	Retail	$146,384	$18,583	$164,967
2	CIP Revenue Adjustment	0		0
3	Interdepartmental	0		0
4	Other Operating	34,933		34,934
5	Gross Earnings Tax	0		0
6	**Total Operating Revenues**	$181,317	$18,583	$199,901
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	$74,867		$74,867
8	Power Production	32,794		32,794
9	Transmission	7,988		7,988
10	Distribution	6,045		6,045
11	Customer Accounting	4,244		4,244
12	Customer Service & Information	332		332
13	Sales, Economic Development & Other	103		103
14	Administrative & General	10,864		10,864
15	Total Operating Expenses	$137,237	$0	$137,237
16	Depreciation	$21,470		$21,470
17	Amortizations	352		352
	Taxes:			
18	Property	$4,956		$4,956
19	Gross Earnings	0		0
20	Deferred Income Tax & ITC	4,819		4,819
21	Federal & State Income Tax	(2,384)	6,504	4,119
22	Payroll & Other	1,452		1,452
23	Total Taxes	$8,843	$6,504	$15,346
24	**Total Expenses**	$167,902	$6,504	$174,407
25	AFUDC	$0		$0
26	**Total Operating Income**	$13,415	$12,079	$25,494

Note: Revenues reflect calendar month sales.

Northern States Power Company, a Minnesota corporation
Electric Utility - State of South Dakota
STATEMENT OF OPERATING INCOME
2006 Actual Reported versus 2008 Pro Forma
($000's)

Docket No. EL09-______
Exhibit___(AEH-1), Schedule 4

Line No.	Description	2006 Actual As Reported (A)	2008 Pro Forma Final Rates (B)	Change (C) = (B) - (A)
	Operating Revenues			
1	Retail	$131,526	$164,967	$33,441
2	CIP Revenue Adjustment	0	0	0
3	Interdepartmental	0	0	0
4	Other Operating	36,240	34,934	(1,306)
5	Gross Earnings Tax	0	0	0
6	**Total Operating Revenues**	$167,766	$199,901	$32,135
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	$63,505	$74,867	$11,362
8	Power Production	29,401	32,794	3,393
9	Transmission	5,761	7,988	2,227
10	Distribution	6,028	6,045	17
11	Customer Accounting	4,060	4,244	184
12	Customer Service & Information	285	332	47
13	Sales, Economic Development & Other	4	103	99
14	Administrative & General	9,473	10,864	1,391
15	Total Operating Expenses	$118,518	$137,237	$18,719
16	Depreciation	$19,303	$21,470	$2,167
17	Amortizations	345	352	7
	Taxes:			
18	Property	$4,538	$4,956	$418
19	Gross Earnings	0	0	0
20	Deferred Income Tax & ITC	(148)	4,819	4,967
21	Federal & State Income Tax	5,885	4,119	(1,766)
22	Payroll & Other	1,032	1,452	420
23	Total Taxes	$11,307	$15,346	$4,039
24	**Total Expenses**	$149,473	$174,407	$24,934
25	AFUDC	$0	$0	$0
26	**Total Operating Income**	$18,293	$25,494	$7,201

Note: Revenues reflect calendar month sales.

($000's)

Line No.	Description	2008 Unadjusted Test Year	Pro Forma Adjustments (1)	2008 Pro Forma
	Electric Plant as Booked			
1	Production	$310,249	$32,574	$342,823
2	Transmission	$77,477	$4,810	$82,287
3	Distribution	$166,887	$8,185	$175,072
4	General	$13,458	$539	$13,997
5	Common	$21,141	$0	$21,141
6	TBT Investment	$0	$0	$0
7	TOTAL Utility Plant in Service	$589,212	$46,108	$635,320
	Reserve for Depreciation			
8	Production	$203,329	$1,318	$204,647
9	Transmission	$26,826	$141	$26,967
10	Distribution	$65,333	$314	$65,647
11	General	$5,091	$45	$5,136
12	Common	$11,690	$0	$11,690
13	TOTAL Reserve for Depreciation	$312,270	$1,818	$314,088
	Net Utility Plant in Service			
14	Production	$106,920	$31,256	$138,176
15	Transmission	$50,651	$4,669	$55,320
16	Distribution	$101,554	$7,871	$109,425
17	General	$8,367	$494	$8,861
18	Common	$9,451	$0	$9,451
19	TBT Investment	$0	$0	$0
20	Net Utility Plant in Service	$276,942	$44,290	$321,232
21	Utility Plant Held for Future Use	$0	$0	$0
22	Construction Work in Progress	$0	$0	$0
23	Less: Accumulated Deferred Income Taxes	$49,023	$6,770	$55,793
24	Cash Working Capital	$2,279	($413)	$1,866
	Other Rate Base Items:			
25	Materials and Supplies	$4,944	$0	$4,944
26	Fuel Inventory	$5,879	$0	$5,879
27	Non-Plant Assets & Liabilities	($6,518)	$3,881	($2,637)
28	Prepayments	$4,942	$0	$4,942
29	Configuration Management		$85	$85
30	Interest on Customer Deposits	($63)	$0	($63)
31	Nuclear Outage - Change of Accting	$987	$916	$1,903
32	Customer Advances	($15)	$0	($15)
33	Other Working Capital	$297	$0	$297
34	Total Other Rate Base Items	$10,453	$4,882	$15,335
35	Total Average Rate Base	$240,651	$41,989	$282,640

Northern States Power Company, a Minnesota corporation
Electric Utility - State of South Dakota
INCOME STATEMENT COMPARISON
2008 PRO FORMA to 2008 UNADJUSTED TEST YEAR
2008 Pro Forma
(Dollars in Thousands)

Line No.	Description	2008 Unadjusted Test Year (A)	Final Increase (B) = (C) - (A)	2008 Pro Forma Final Rates (C)
	Operating Revenues			
1	Retail	$146,879	($495)	$146,384
2	CIP Revenue Adjustment	0	0	0
3	Interdepartmental	0	0	0
4	Other Operating	36,505	(1,572)	34,933
5	Gross Earnings Tax	0	0	0
6	**Total Operating Revenues**	$183,384	($2,067)	$181,317
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	$76,263	($1,396)	$74,867
8	Power Production	30,517	2,277	32,794
9	Transmission	7,551	437	7,988
10	Distribution	5,917	128	6,045
11	Customer Accounting	4,212	32	4,244
12	Customer Service & Information	415	(83)	332
13	Sales, Econ Dvlp & Other	3	100	103
14	Administrative & General	9,917	947	10,864
15	Total Operating Expenses	$134,795	$2,442	$137,237
16	Depreciation	$20,214	$1,256	$21,470
17	Amortizations	4	348	352
	Taxes:			
18	Property	$4,436	$520	$4,956
19	Gross Earnings	0	0	0
20	Deferred Income Tax & ITC	5,119	(300)	4,819
21	Federal & State Income Tax	340	(2,724)	(2,384)
22	Payroll & Other	1,381	71	1,452
23	Total Taxes	$11,276	($2,433)	$8,843
24	**Total Expenses**	$166,289	$1,613	$167,902
25	AFUDC	$0	$0	$0
26	**Total Operating Income**	$17,095	($3,680)	$13,415

Note: Revenues reflect calendar month sales.

	Distribution	Transmission	Total	Average
1993	$ 689,698		$ 689,698	
1994	$ 964,300		$ 964,300	
1995	$ 812,042		$ 812,042	
1996	$ 888,171		$ 888,171	
1997	$ 913,547		$ 913,547	
1998	$ 748,556	$ 155,264	$ 903,821	
1999	$ 880,839	$ 50,546	$ 931,385	
2000	$ 857,313	$ 168,722	$ 1,026,035	
2001	$ 825,363	$ 123,396	$ 948,760	
2002	$ 921,618	$ 144,657	$ 1,066,276	
2003	$ 1,286,503	$ 134,722	$ 1,421,225	
2004	$ 1,027,674	$ 151,646	$ 1,179,321	
2005	$ 937,003	$ 174,732	$ 1,111,734	
2006	$ 187,868	$ 1,279,499	$ 1,467,367	
2007	$ 1,732,634	$ 191,250	$ 1,923,884	
2008	$ 944,836	$ 219,861	$ 1,164,697	
			$ 17,412,263	**$ 1,088,266**
2009B	$ 1,055,428	$ 242,732	$ 1,298,160	

The tree trimming costs reflect contract labor and equipment, but do not include any internal labor or management costs associated with NSP Minnesota tree trimming costs.
1993 to 1997 data from information provided to South Dakota Commission in 2003

Northern States Power Company, a Minnesota corporation
Electric Utility - State of South Dakota
RATE BASE SCHEDULES
RATE BASE ADJUSTMENT SCHEDULES
2008 Unadjusted Test Year versus 2008 Pro Forma Test Year
($000's)

Docket No. EL09-____
Exhibit___(AEH-1) Schedule 7a

Line No.	Description	Unadjusted	Adjustments: Configuration Management (1)	FAS 106 Post Medical Retirement (PayGo) (2)	Nuclear Outage Change of Acctg (3)	2008 Plant Adjustment (4)	2008 PI Plant Adjustment (5)	2009 Plant Adjustment (6)	2009 PI Plant Adjustment (7)	2010 Riverside Plant Adjustment (8)	PI Remaining Life +3 (9)	End of Life Nuclear Fuel PI +3 (10)	Income Statement (11)	Pro Forma
	Electric Plant as Booked													
1	Production	$310,249				$17,077	$1,072	$9,033	$1,013	$4,379				$342,823
2	Transmission	$77,477				$3,299		$1,511						$82,287
3	Distribution	$166,887				$4,355		$3,830						$175,072
4	General	$13,458				$539								$13,997
5	Common	$21,141												$21,141
6	TBT Investment	$0												$0
7	TOTAL Utility Plant in Service	$589,212	$0	$0	$0	$25,270	$1,072	$14,374	$1,013	$4,379	$0	$0		$635,320
	Reserve for Depreciation													
8	Production	$203,329				$930	$161	$123	$39	$378	($391)	$78		$204,647
9	Transmission	$26,826				$128		$13						$26,967
10	Distribution	$65,333				$272		$42						$65,647
11	General	$5,091				$45								$5,136
12	Common	$11,690												$11,690
13	TOTAL Reserve for Depreciation	$312,270	$0	$0	$0	$1,375	$161	$178	$39	$378	($391)	$78		$314,088
	Net Utility Plant in Service													
14	Production	$106,920				$16,147	$911	$8,910	$974	$4,001	$391	($78)		$138,176
15	Transmission	$50,651				$3,171		$1,498						$55,320
16	Distribution	$101,554				$4,083		$3,788						$109,425
17	General	$8,367				$494								$8,861
18	Common	$9,451												$9,451
19	TBT Investment	$0												$0
20	Net Utility Plant in Service	$276,942	$0	$0	$0	$23,895	$911	$14,196	$974	$4,001	$391	($78)		$321,232
21	Utility Plant Held for Future Use	$0												$0
22	Construction Work in Progress	$0												$0
23	Less: Accumulated Deferred Income Taxes	$49,023	$30	$1,550	$374	$2,868	$62	$1,410	$181	$167	$160	($32)		$55,793
24	Cash Working Capital	$2,279											($413)	$1,866
	Other Rate Base Items:													
25	Materials and Supplies	$4,944												$4,944
26	Fuel Inventory	$5,879												$5,879
27	Non-Plant Assets & Liabilities	($6,518)		$3,881										($2,637)
28	Prepayments	$4,942												$4,942
29	Configuration Management		$85											$85
30	Interest on Customer Deposits	($63)												($63)
31	Nuclear Outage - Change of Accting	$987			$916									$1,903
32	Customer Advances	($15)												($15)
33	Other Working Capital	$297												$297
34	Total Other Rate Base Items	$10,453	$85	$3,881	$916	$0	$0	$0	$0	$0	$0	$0	$0	$15,335
35	Total Average Rate Base	$240,651	$55	$2,331	$542	$21,027	$849	$12,786	$793	$3,834	$231	($46)	($413)	$282,640

($000's)

	South Dakota Unadjusted Test Year	PF 1 Configuration Management	PF 2 Economic Development 1st $100	PF 2 Economic Development 2nd $100	PF 3 Advertising	PF 4 Association Dues	PF 5 Donations	PF 6 Interest on Customer Deposits	PF 7 Incentive Pay 2008 Out
Income Statement									
Operating Revenues									
Retail	146,879	-	-	-	-	-	-	-	-
CIP Adjustment to Program Costs	-	-	-	-	-	-	-	-	-
Interdepartmental	-	-	-	-	-	-	-	-	-
Other Operating	36,505	-	-	-	-	-	-	-	-
Gross Earnings Tax	-	-	-	-	-	-	-	-	-
Total Operating Revenues	183,384	-	-	-	-	-	-	-	-
Expenses									
Operating Expenses:									
Fuel & Purchased Energy	76,263	-	-	-	-	-	-	-	-
Power Production	30,517	-	-	-	-	-	-	-	-
Transmission	7,551	-	-	-	-	-	-	-	-
Distribution	5,917	-	-	-	-	-	-	-	-
Customer Accounting	4,212	-	-	-	-	-	-	-	-
Customer Service & Information	415	-	-	-	-	-	-	-	-
Sales, Econ Dvlp & Other	3	-	50	50	-	-	-	-	-
Administrative & General	9,917	-	-	-	(191)	(1)	59	4	(212)
Total Operating Expenses	134,795	-	50	50	(191)	(1)	59	4	(212)
Depreciation	20,214	-	-	-	-	-	-	-	-
Amortization	4	57	-	-	-	-	-	-	-
Taxes:									
Property	4,436	-	-	-	-	-	-	-	-
Gross Earnings	-	-	-	-	-	-	-	-	-
Deferred Income Tax & ITC	5,119	(20)	-	-	-	-	-	-	-
State & Federal Income	340	(1)	(18)	(18)	67	0	(21)	(1)	74
Payroll & Other	1,381	-	-	-	-	-	-	-	-
Total Taxes	11,276	(21)	(18)	(18)	67	0	(21)	(1)	74
Total Expenses	166,289	36	33	33	(124)	(1)	38	3	(138)
AFUDC	-	-	-	-	-	-	-	-	-
Total Operating Income	17,095	(36)	(33)	(33)	124	1	(38)	(3)	138
Revenue Requirement									
Total Rate Base	240,651	55	-	-	-	-	-	-	-
Require Operating Inc (Rate Base * Req Return)	21,707	5	-	-	-	-	-	-	-
Operating Income	17,095	(36)	(33)	(33)	124	1	(38)	(3)	138
Operating Income Deficiency	4,612	41	33	33	(124)	(1)	38	3	(138)
Revenue Requirement	7,095	63	50	50	(191)	(1)	59	4	(212)

($000's)

	PF 7 Incentive Pay 2009 In	PF 8 Remove 2008 Insurance Credit	PF 9 SD Private Fuel Storage Amort	PF 10 Rate Case Expense Amort	PF 11 SD Emissions Sales Amortization	PF 12 SD RDF Amortiaztion	PF 13 Postage increase 2009	PF 13 Postage increase 2010	PF 14 Wage Increase Including Payroll Tax (Union 2009 & 2010)
Income Statement									
Operating Revenues									
Retail	-	-	-	-	-	-	-	-	-
CIP Adjustment to Program Costs	-	-	-	-	-	-	-	-	-
Interdepartmental	-	-	-	-	-	-	-	-	-
Other Operating	-	-	-	-	-	-	-	-	-
Gross Earnings Tax	-	-	-	-	-	-	-	-	-
Total Operating Revenues	-	-	-	-	-	-	-	-	-
Expenses									
Operating Expenses:									
Fuel & Purchased Energy	-	-	-	-	-	-	-	-	-
Power Production	-	-	-	-	-	-	-	-	391
Transmission	-	-	-	-	-	-	-	-	37
Distribution	-	-	-	-	-	-	-	-	128
Customer Accounting	-	-	-	-	-	-	15	17	-
Customer Service & Information	-	-	-	-	-	-	-	-	-
Sales, Econ Dvlp & Other	-	-	-	-	-	-	-	-	-
Administrative & General	839	47	-	-	-	-	-	-	-
Total Operating Expenses	839	47	-	-	-	-	15	17	556
Depreciation	-	-	-	-	-	-	-	-	-
Amortization	-	-	169	98	(84)	108	-	-	-
Taxes:									
Property	-	-	-	-	-	-	-	-	-
Gross Earnings	-	-	-	-	-	-	-	-	-
Deferred Income Tax & ITC	-	-	-	-	-	-	-	-	-
State & Federal Income	(294)	(16)	(59)	(34)	29	(38)	(5)	(6)	(212)
Payroll & Other	-	-	-	-	-	-	-	-	51
Total Taxes	(294)	(16)	(59)	(34)	29	(38)	(5)	(6)	(161)
Total Expenses	545	31	110	64	(55)	70	10	11	395
AFUDC	-	-	-	-	-	-	-	-	-
Total Operating Income	(545)	(31)	(110)	(64)	55	(70)	(10)	(11)	(395)
Revenue Requirement									
Total Rate Base	-	-	-	-	-	-	-	-	-
Require Operating Inc (Rate Base * Req Return)	-	-	-	-	-	-	-	-	-
Operating Income	(545)	(31)	(110)	(64)	55	(70)	(10)	(11)	(395)
Operating Income Deficiency	545	31	110	64	(55)	70	10	11	395
Revenue Requirement	839	47	169	98	(84)	108	15	17	607

($000's)

	PF 14 Wage Increase Including Payroll Tax (Non-union annualize 2008 and 2% 2009)	PF 15 Nuclear Mandates - Fitness for Duty	PF 16 DSM Adjustment	PF 17 FAS 106 Post Medical Retirement (PayGo)	PF 18 Weather Normalization	PF 19 Asset/Non-Asset Based Margins	PF 20 Nuclear Change of Accounting Normalization	PF 21 Joint Zonal Pricing Adjustment
Income Statement								
Operating Revenues								
Retail	-	-	-	-	-	-	-	-
CIP Adjustment to Program Costs	-	-	-	-	-	-	-	-
Interdepartmental	-	-	-	-	-	-	-	-
Other Operating	-	-	-	-	-	(1,810)	-	238
Gross Earnings Tax	-	-	-	-	-	-	-	-
Total Operating Revenues	-	-	-	-	-	(1,810)	-	238
Expenses								
Operating Expenses:								
Fuel & Purchased Energy	-	-	-	-	(902)	-	-	-
Power Production	-	220	-	-	-	-	1,567	-
Transmission	-	-	-	-	-	-	-	400
Distribution	-	-	-	-	-	-	-	-
Customer Accounting	-	-	-	-	-	-	-	-
Customer Service & Information	-	-	(83)	-	-	-	-	-
Sales, Econ Dvlp & Other	-	-	-	-	-	-	-	-
Administrative & General	218	-	-	37	-	-	-	-
Total Operating Expenses	218	220	(83)	37	(902)	-	1,567	400
Depreciation	-	-	-	-	-	-	-	-
Amortization	-	-	-	-	-	-	-	-
Taxes:								
Property	-	-	-	-	-	-	-	-
Gross Earnings	-	-	-	-	-	-	-	-
Deferred Income Tax & ITC	-	-	-	26	-	-	(651)	-
State & Federal Income	(83)	(77)	29	(63)	316	(634)	3	(57)
Payroll & Other	20	-	-	-	-	-	-	-
Total Taxes	(63)	(77)	29	(37)	316	(634)	(648)	(57)
Total Expenses	155	143	(54)	(0)	(586)	(634)	919	343
AFUDC	-	-	-	-	-	-	-	-
Total Operating Income	(155)	(143)	54	0	586	(1,177)	(919)	(105)
Revenue Requirement								
Total Rate Base	-	-	-	2,331	-	-	542	-
Require Operating Inc (Rate Base * Req Return)	-	-	-	210	-	-	49	-
Operating Income	(155)	(143)	54	0	586	(1,177)	(919)	(105)
Operating Income Deficiency	155	143	(54)	210	(586)	1,177	968	105
Revenue Requirement	238	220	(83)	323	(902)	1,810	1,489	162

($000's)

	PF 22 Employee Expense Adjustment	PF 23 Benefit Adjustment - Pension	PF 23 Benefit Adjustment - Active Health	PF 24 2008 Plant Adjustments	PF 25 2008 PI Plant Adjustment	PF 26 2009 Plant Adjustment	PF 27 2009 PI Plant Adjustment	PF 28 2010 Riverside Plant Adjustment
Income Statement								
Operating Revenues								
Retail	-	-	-	-	-	-	-	-
CIP Adjustment to Program Costs	-	-	-	-	-	-	-	-
Interdepartmental	-	-	-	-	-	-	-	-
Other Operating	-	-	-	-	-	-	-	-
Gross Earnings Tax	-	-	-	-	-	-	-	-
Total Operating Revenues	-	-	-	-	-	-	-	-
Expenses								
Operating Expenses:								
Fuel & Purchased Energy	-	-	-	-	-	-	-	-
Power Production	-	-	-	-	-	-	-	-
Transmission	-	-	-	-	-	-	-	-
Distribution	-	-	-	-	-	-	-	-
Customer Accounting	-	-	-	-	-	-	-	-
Customer Service & Information	-	-	-	-	-	-	-	-
Sales, Econ Dvlp & Other	-	-	-	-	-	-	-	-
Administrative & General	(135)	95	187	-	-	-	-	-
Total Operating Expenses	(135)	95	187	-	-	-	-	-
Depreciation	-	-	-	1,008	133	519	125	157
Amortization	-	-	-	-	-	-	-	-
Taxes:								
Property	-	-	-	282	13	156	12	57
Gross Earnings	-	-	-	-	-	-	-	-
Deferred Income Tax & ITC	-	-	-	(3,104)	(199)	2,820	372	195
State & Federal Income	47	(33)	(65)	1,487	105	(2,556)	(277)	(359)
Payroll & Other	-	-	-	-	-	-	-	-
Total Taxes	47	(33)	(65)	(1,335)	(81)	420	107	(107)
Total Expenses	(88)	62	122	(327)	52	939	232	50
AFUDC	-	-	-	-	-	-	-	-
Total Operating Income	88	(62)	(122)	327	(52)	(939)	(232)	(50)
Revenue Requirement								
Total Rate Base	-	-	-	21,027	849	12,786	793	3,834
Require Operating Inc (Rate Base * Req Return)	-	-	-	1,897	77	1,153	72	346
Operating Income	88	(62)	(122)	327	(52)	(939)	(232)	(50)
Operating Income Deficiency	(88)	62	122	1,570	128	2,092	303	395
Revenue Requirement	(135)	95	187	2,415	198	3,219	466	608

($000's)

	PF 29 PI Remaining Life + 3	PF 30 End of Life Nuclear fuel PI + 3	PF 31 Nuclear Decommissioning PI + 3	PF 32 Manufacture Production Deduction	PF 33 MISO Schedule 24 Adjustment	PF 34 Remove FCA Lag Adjustment	Cash Working Capital	South Dakota Proforma
Income Statement								
Operating Revenues								
Retail	-	-	-	-	-	(495)	-	146,384
CIP Adjustment to Program Costs	-	-	-	-	-	-	-	-
Interdepartmental	-	-	-	-	-	-	-	-
Other Operating	-	-	-	-	-	-	-	34,933
Gross Earnings Tax	-	-	-	-	-	-	-	-
Total Operating Revenues	-	-	-	-	-	(495)	-	181,317
								-
Expenses								-
Operating Expenses:								-
Fuel & Purchased Energy	-	-	-	-	1	(495)	-	74,867
Power Production	-	155	-	-	(56)	-	-	32,794
Transmission	-	-	-	-	-	-	-	7,988
Distribution	-	-	-	-	-	-	-	6,045
Customer Accounting	-	-	-	-	-	-	-	4,244
Customer Service & Information	-	-	-	-	-	-	-	332
Sales, Econ Dvlp & Other	-	-	-	-	-	-	-	103
Administrative & General	-	-	-	-	-	-	-	10,864
Total Operating Expenses	-	155	-	-	(55)	(495)	-	137,237
								-
Depreciation	(795)	-	109	-	-	-	-	21,470
Amortization	-	-	-	-	-	-	-	352
								-
Taxes:								-
Property	-	-	-	-	-	-	-	4,956
Gross Earnings	-	-	-	-	-	-	-	-
Deferred Income Tax & ITC	324	(63)	-	-	-	-	-	4,819
State & Federal Income	(3)	1	-	24	19	0	5	(2,384)
Payroll & Other	-	-	-	-	-	-	-	1,452
Total Taxes	321	(62)	-	24	19	0	5	8,844
								-
Total Expenses	(474)	93	109	24	(36)	(495)	5	167,902
								-
AFUDC	-	-	-	-	-	-	-	-
Total Operating Income	474	(93)	(109)	(24)	36	(0)	(5)	13,415
								-
Revenue Requirement								
Total Rate Base	231	(46)	-	-	-	-	(413)	282,640
Require Operating Inc (Rate Base * Req Return)	21	(4)	-	-	-	-	(37)	25,494
Operating Income	474	(93)	(109)	(24)	36	(0)	(5)	13,415
Operating Income Deficiency	(453)	88	109	24	(36)	0	(32)	12,079
Revenue Requirement	(697)	136	168	37	(55)	0	(50)	18,583

The allocation factors on this page were used to determine South Dakota jurisdictional operating income amounts for all of the years presented in these schedules. Accounts not on this page have been directly asigned to jurisdiction.

Line No.	Description	Allocation Basis
1	Fuel & Purchased Energy	Energy
2	Power Production Expense	Demand - Production
3	Transmission Expense	Demand - Transmission
4	Distribution Expense	Customers
5	Customer Accounting Expense	Customers
6	Customer Service & Info Expense	Customers
7	Sales Expense	Customers
8	Administrative & General	Customers Demand - Production Demand - Transmission TwoFactor

Unadjusted Test Year 2008

Line No.	Allocation Factor	Total Utility	South Dakota Jurisdiction	Allocation Factor
1	Demand - Prod(1)	67,538,820	3,467,451	5.1340%
2	Demand - Tran (2)	67,538,820	3,467,451	5.1340%
3	Energy (3)	38,279,092	2,026,038	5.2928%
4	Customers(4)	1,376,160	80,585	5.8558%
5	TwoFactor	100.0000%	5.5167%	

Line No.	Allocation Factor	Total Utility	MN Utility	WI Utility
6	36 mth Demand	100.0000%	84.4224%	15.5776%
7	36 mth Energy	100.0000%	84.1229%	15.8771%

(1) Demand w/o Contract Services
(2) Demand
(3) Energy
(4) Average number of Customers
(5) TwoFactor
(6) 36 Mth Demand
(7) 36 Mth Energy

Unadjusted Test Year 2008

Line No.	Allocation Factor	Total Utility	South Dakota Jurisdiction	Allocation Factor
1	Demand - Production	67,538,820	3,467,451	5.1340%
2	Demand - Transmission	67,538,820	3,467,451	5.1340%
3	Energy	38,279,092	2,026,038	5.2928%
4	Customers	1,376,160	80,585	5.8558%
5	TwoFactor	see page 4		

Line No.	Allocation Factor	Total Utility	MN Jurisdiction	WI Jurisdiction
6	36 Mth Demand	100.0000%	84.4224%	15.5776%
7	36 Mth Energy	100.0000%	84.1229%	15.8771%

(1) Demand w/o Contract Services
(2) Demand
(3) Energy
(4) Average number of Customers
(5) TwoFactor
(6) 36 Mth Demand
(7) 36 Mth Energy

Alloctors for Common and General Plant
for 2008 Actual
Based on 2007 Actual Data

O&M Allocator

O&M excluding A&G	2007 Actuals	Ratio
Production	$ 400,645,284	56.80%
Transmission	$ 70,759,160	10.03%
Distribution/Customer	$ 233,933,370	33.17%
	$ 705,337,814	100.00%

Plant in Service used to allocate Electric General Plant
Source - 2007 FERC Form 1
Pages 204-207

	2007 Year End Balance	Ratio
Production	$ 4,476,800,295	51.77%
Transmission	$ 1,435,314,360	16.60%
Distribution	$ 2,735,476,393	31.63%
	$ 8,647,591,048	100.00%

Combined Allocator used for Electric Portion of Common Plant
Equally Weighted Plant in Service and O&M ratio

Production	54.2856%
Transmission	13.3149%
Distribution	32.3995%
	100.0000%

08 Actual Allocators

EProd Demand Alloc

MN	86.7317%
ND	5.6655%
SD	5.1340%
WHLSL	2.4688%
	100.0000%

ETrans Demand Alloc

MN	86.7317%
ND	5.6655%
SD	5.1340%
WHLSL	2.4688%
	100.0000%

ECustomerMN/SD/ND

MN	87.8367%
ND	6.3066%
SD	5.8558%
WHLSL	0.0009%
	100.0000%

2008 Actual A&G Jurisdicational Allocators

ELECTRIC A&G Alloc

2 Factor Allocator	O&M and Plant	MN	ND	SD	WHLSL	Check
Production	54.2856%	47.2681%	2.9927%	2.9041%	1.1208%	54.2856%
Transmission	13.3149%	11.5937%	0.7340%	0.7123%	0.2749%	13.3149%
Distribution/Customers	32.3995%	28.4642%	2.0347%	1.9003%	0.0003%	32.3995%
Resulting Allocator	**100.00%**	**87.3260%**	**5.7614%**	**5.5167%**	**1.3959%**	**100.0000%**

($000's)

Ln	Adjustment Description	Adjustment Target	Total Company Amount	SD Jurisdiction Amount	Allocation Method	Source of Data- All Volume 4 Tal
1	PF 1Configuration Managemenl	Accumulated Deferred Taxes BOY	30	30	Demand/Energy	PF1
2		Accumulated Deferred Taxes EOY	30	30	Demand/Energy	PF1
3		Prepayments & Other BOY	85	85	Demand/Energy	PF1
4		Prepayments & Other EOY	85	85	Demand/Energy	PF1
5		Amortizations	57	57	Demand/Energy	PF1
6		Deferred Income Tax	(20)	(20)	Demand/Energy	PF1
7		Tax Additions	57	57	Demand/Energy	PF1
8	PF 2 Economic Development 1st $10C	Sales, Econ Dvlp & Other	189	50	Direct	PF2
9	PF 2 Economic Development 2nd $10C	Sales, Econ Dvlp & Other	50	50	Direct	PF2
10	PF 3 Advertising	Administrative & General	(3,589)	(191)	Multiple	PF3
11	PF 4 Association Dues	Administrative & General	(11)	(1)	Multiple	PF4
12	PF 5 Donations	Administrative & General	1,657	59	Direct	PF5
13	PF 6 Interest on Customer Deposits	Administrative & General	73	4	Customers	PF6
14	PF 7 Incentive Pay 2008 Out	Administrative & General	(9,738)	(212)	Multiple	PF7
15	PF 7 Incentive Pay 2009 In	Administrative & General	15,639	839	Multiple	PF7
16	PF 8 Remove 2008 Insurance Credit	Administrative & General	851	47	Electric A&G	PF8
17	PF 9 SD Private Fuel Storage Amort	Amortization	169	169	Demand	PF9
18	PF 10 Rate Case Expense Amort	Amortization	98	98	Direct	PF10
19	PF 11 SD Emissions Sales Amortization	Amortization	(84)	(84)	Direct	PF11
20	PF 12 SD RDF Amortiaztion	Amortization	108	108	Direct	PF12
21	PF 13 Postage increase 2009	Customer Accounting	261	15	Customers	PF13
22	PF 13 Postage increase 2010	Customer Accounting	290	17	Customers	PF13
23	PF 14 Wage Increase Including Payroll Tax (Union)	Power Production	8,256	391	Labor	PF14
24		Transmission	781	37	Labor	PF14
25		Distribution	2,695	128	Labor	PF14
26	PF 14 Wage Increase Including Payroll Tax (Non-union)	Administrative & General	4,116	218	Labor	PF14
27	PF 15 Nuclear Mandates - Fitness for Duty	Power Production	4,288	220	Demand	PF15
28	PF 16 DSM Adjustment	Customer Service & Information	(83)	(83)	Direct	PF16

($000's)

Ln	Adjustment Description	Adjustment Target	Total Company Amount	SD Jurisdiction Amount	Allocation Method	Source of Data- All Volume 4 Tal
1	PF 17 FAS 106 Post Medical Retirement (PayGo)	Accumulated Deferred Taxes BOY	28,902	1,550	Labor	PF17
2		Accumulated Deferred Taxes EOY	28,902	1,550	Labor	PF17
3		Non-Plant asset & Liab BOY	72,362	3,881	Labor	PF17
4		Non-Plant asset & Liab EOY	72,362	3,881	Labor	PF17
5		Administrative & General	677	37	Multiple	PF17
6		Deferred Income Tax	484	26	Labor	PF17
7		Tax Deductions	1,295	69	Labor	PF17
8	PF 18 Weather Normalization	Fuel & Purchased Energy	(7,163)	(902)	Direct	PF18
9	PF 19 Asset/Non-Asset Based Margins	Other Revenue	(3,460)	(1,810)	Energy	PF19
10	PF 20 Nuclear Change of Accounting Normalization	Accumulated Deferred Taxes BOY	7,300	374	Composite Allocation Factor	PF20
11		Accumulated Deferred Taxes EOY	7,300	374	Composite Allocation Factor	PF20
12		Prepayments & Other BOY	17,871	916	Composite Allocation Factor	PF20
13		Prepayments & Other EOY	17,871	916	Composite Allocation Factor	PF20
14		Power Production	30,565	1,567	Composite Allocation Factor	PF20
15		Deferred Income Tax	(12,695)	(651)	Composite Allocation Factor	PF20
16		Tax Additions	30,565	1,567	Composite Allocation Factor	PF20
17		Tax Deductions	(511)	(26)	Composite Allocation Factor	PF20
18	PF 21 Joint Zonal Pricing Adjustment	Other Revenue	4,644	238	Demand	PF21
19		Transmission	7,787	400	Demand	PF21
20	PF 22 Employee Expense Adjustment	Administrative & General	(2,502)	(135)	Electric O&M Labor	PF22
21	PF 23 Benefit Adjustment - Retirement	Administrative & General	1,763	95	Electric Pension & Benefit	PF23
22	PF 23 Benefit Adjustment - Health Care	Administrative & General	3,465	187	Electric Pension & Benefit	PF23
23	PF 24 2008 Plant Adjustments	Plant Investment BOY	410,560	25,270	Demand\Direct	PF24
24		Plant Investment EOY	410,560	25,270	Demand\Direct	PF24
25		Depreciation Reserve BOY	21,646	1,375	Demand\Direct	PF24
26		Depreciation Reserve EOY	21,646	1,375	Demand\Direct	PF24
27		Accumulated Deferred Taxes BOY	40,384	2,868	Demand\Direct	PF24
28		Accumulated Deferred Taxes EOY	40,384	2,868	Demand\Direct	PF24
29		Depreciation	17,218	1,008	Demand\Direct	PF24
30		Property Tax	4,857	282	Demand\Direct	PF24
31		Deferred Income Tax	(31,799)	(3,104)	Demand\Direct	PF24
32		Tax Additions	(15,688)	(865)	Demand\Direct	PF24
33		Tax Deductions	(67,990)	(6,954)	Demand\Direct	PF24
34		Production Tax Credit	6,011	309	Demand\Direct	PF24

($000's)

Ln	Adjustment Description	Adjustment Target	Total Company Amount	SD Jurisdiction Amount	Allocation Method	Source of Data- All Volume 4 Tal
1	PF 25 2008 PI Plant Adjustment	Plant Investment BOY	20,876	1,072	Demand	PF25
2		Plant Investment EOY	20,876	1,072	Demand	PF25
3		Depreciation Reserve BOY	3,134	161	Demand	PF25
4		Depreciation Reserve EOY	3,134	161	Demand	PF25
5		Accumulated Deferred Taxes BOY	1,217	62	Demand	PF25
6		Accumulated Deferred Taxes EOY	1,217	62	Demand	PF25
7		Depreciation	2,585	133	Demand	PF25
8		Property Tax	253	13	Demand	PF25
9		Deferred Income Tax	(3,867)	(199)	Demand	PF25
10		Tax Additions	(861)	(44)	Demand	PF25
11		Tax Deductions	(7,476)	(384)	Demand	PF25
12	PF 26 2009 Plant Adjustment	Plant Investment BOY	209,204	14,374	Demand\Direct	PF26
13		Plant Investment EOY	209,204	14,374	Demand\Direct	PF26
14		Depreciation Reserve BOY	2,687	178	Demand\Direct	PF26
15		Depreciation Reserve EOY	2,687	178	Demand\Direct	PF26
16		Accumulated Deferred Taxes BOY	16,456	1,410	Demand\Direct	PF26
17		Accumulated Deferred Taxes EOY	16,456	1,410	Demand\Direct	PF26
18		Depreciation	7,929	519	Demand\Direct	PF26
19		Property Tax	2,473	156	Demand\Direct	PF26
20		Deferred Income Tax	32,912	2,820	Demand\Direct	PF26
21		Tax Additions	23,871	1,278	Demand\Direct	PF26
22		Tax Deductions	100,173	8,015	Demand\Direct	PF26
23	PF 27 2009 PI Plant Adjustment	Plant Investment BOY	19,725	1,013	Demand	PF27
24		Plant Investment EOY	19,725	1,013	Demand	PF27
25		Depreciation Reserve BOY	750	39	Demand	PF27
26		Depreciation Reserve EOY	750	39	Demand	PF27
27		Accumulated Deferred Taxes BOY	3,518	181	Demand	PF27
28		Accumulated Deferred Taxes EOY	3,518	181	Demand	PF27
29		Depreciation	2,436	125	Demand	PF27
30		Property Tax	239	12	Demand	PF27
31		Deferred Income Tax	7,251	372	Demand	PF27
32		Tax Additions	9,942	510	Demand	PF27
33		Tax Deductions	24,644	1,265	Demand	PF27

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of South Dakota
SUMMARY OF TEST PERIOD ADJUSTMENTS
Test Year Ending December 31, 2009
($000's)

Ln	Adjustment Description	Adjustment Target	Total Company Amount	SD Jurisdiction Amount	Allocation Method	Source of Data- All Volume 4 Tal
1	PF 28 2010 Riverside Plant Adjustment	Plant Investment BOY	85,299	4,379	Demand	PF28
2		Plant Investment EOY	85,299	4,379	Demand	PF28
3		Depreciation Reserve BOY	7,369	378	Demand	PF28
4		Depreciation Reserve EOY	7,369	378	Demand	PF28
5		Accumulated Deferred Taxes BOY	3,257	167	Demand	PF28
6		Accumulated Deferred Taxes EOY	3,257	167	Demand	PF28
7		Depreciation	3,060	157	Demand	PF28
8		Property Tax	1,113	57	Demand	PF28
9		Deferred Income Tax	3,794	195	Demand	PF28
10		Tax Additions	(8,547)	(439)	Demand	PF28
11		Tax Deductions	7,946	408	Demand	PF28
12	PF 29 PI Remaining Life + 3	Depreciation Reserve BOY	(7,624)	(391)	Demand	PF29
13		Depreciation Reserve EOY	(7,624)	(391)	Demand	PF29
14		Accumulated Deferred Taxes BOY	3,112	160	Demand	PF29
15		Accumulated Deferred Taxes EOY	3,112	160	Demand	PF29
16		Depreciation	(15,477)	(795)	Demand	PF29
17		Deferred Income Tax	6,318	324	Demand	PF29
18	PF 30 End of Life Nuclear fuel PI + 3	Depreciation Reserve BOY	1,511	78	Demand	PF30
19		Depreciation Reserve EOY	1,511	78	Demand	PF30
20		Accumulated Deferred Taxes BOY	(617)	(32)	Demand	PF30
21		Accumulated Deferred Taxes EOY	(617)	(32)	Demand	PF30
22		Power Production	3,023	155	Demand	PF30
23		Deferred Income Tax	(1,234)	(63)	Demand	PF30
24		Tax Additions	3,023	155	Demand	PF30
25	PF 31 Nuclear Decommissioning PI + 3	Depreciation	109	109	Demand	PF31
26	PF 33 MISO Schedule 24 Adjustment	Fuel & Purchased Energy	1	1	Energy	PF33
27		Power Production	(56)	(56)	Demand	PF33
28	PF 34 Remove FCA Lag Adjustment	Retail Revenue	(495)	(495)	Direct	PF34
29		Fuel & Purchased Energy	(495)	(495)	Direct	PF34

		50% Recovery
Foundation Grants		$36,500
Arts & Culture	$29,700	
Community Development	$17,400	
Education	$25,900	
	$73,000	
Matching Programs		$4,602
Dollars for Doing	$535	
Higher Education	$7,244	
Not for Profit 501c3	$1,425	
	$9,204	
United Way	$14,984	$7,492
Community Grants	$19,973	$9,987
	$117,161	58,581

FocusArea	Program	FLName	City	State	Grant	BriefPurpose
Arts and Culture	Foundation	Children's Care Hospital and School, Inc.	Sioux Falls	SD	$2,000	Experiencing the Arts is a part of our Art of Healing and Growing program at Children's Care. Grant money would allow for children to experience artistic performances appropriate for their age and developmental levels while enriching their lives and givi
Arts and Culture	Foundation	McCrossan Boys Ranch	Sioux Falls	SD	$3,000	We are requesting funds to support our Native American Cultural Diversity Program for at-risk youth at McCrossan Boys Ranch. We would like to open a Native American Resource Room filled with books, craft supplies and more for our boys to enhance their edu
Arts and Culture	Foundation	Multi-Cultural Center	Sioux Falls	SD	$5,000	The Festival of Cultures is an annual event that highlights the growing diversity of the City of Sioux Falls. This is a free, family-friendly event that celebrates cultural traditions past and present in the area and promotes cross-cultural understanding
Arts and Culture	Foundation	Sioux Empire Arts Council	Sioux Falls	SD	$4,000	The Sioux Empire Arts Council requests funding to offer the Student Mentoring: SculptureWalk program offered to area high school students.
Arts and Culture	Foundation	Sioux Falls Area Community Foundation, Inc.	Sioux Falls	SD	$8,500	To provide a public venue for emerging musicians and to increase the impact of the arts on our community and culture. Part of the funding would also be used to support the SculptureWalk program, which provides a public venue for sculptors and spectators t
Arts and Culture	Foundation	South Dakota Symphony Orchestra	Sioux Falls	SD	$3,200	This request is for tuition assistance for students enrolling in the new SD Symphony Youth Orchestra.
Arts and Culture	Foundation	Washington Pavilion Management, Inc.	Sioux Falls	SD	$4,000	The Washington Pavilion of Arts and Science will continue to serve its mission of bringing the visual arts to the Sioux Falls community through participation in SculptureWalk 2008 Sioux Falls.
Arts and Culture Total					**$29,700**	
Community Develop	Foundation	Lutheran Social Services of South Dakota	Sioux Falls	SD	$7,000	First-time home owners face many questions, uncertainties, and challenges. To meet the education needs of new home owners, Consumer Credit Counseling Service, a program of Lutheran Social Services of South Dakota, will offer a monthly series of free work
Community Develop	Foundation	The Salvation Army	Sioux Falls	SD	$10,400	Xcel grant funds would enable us to provide continuing energy assistance to members of the community for the 2008-2009 budget year. Funding will also help us coordinate painting homes of needy seniors and permanently disabled persons in the community.
Community Development Total					**$17,400**	
Education	Foundation	Augustana College	Sioux Falls	SD	$1,000	Augustana College respectfully requests the Xcel Energy Foundation support a $1,000 scholarship to be awarded to a student who plans to major in math, science, or a technical or environmental field. The scholarship will be awarded to a student attending
Education	Foundation	Girl Scouts- Dakota Horizons	Sioux Falls	SD	$2,500	CEO-University is a cutting-edge developmental experience that encourages participants to grow academically and emotionally. Girls gain confidence as they master new skills, explore business and technology, discover their leadership style, achieve success
Education	Foundation	Kilian Community College	Sioux Falls	SD	$5,000	Kilian Community College, a private, non-profit institution of higher education, is seeking funding for the Bridges Program, which helps adult refugees and immigrants develop their ability to read and write academic-level English, thus preparing them for
Education	Foundation	Mitchell Technical Institute Foundation	Mitchell	SD	$1,000	Mitchell Technical Institute would like to continue the Xcel Energy Scholarship for students who are enrolled in one of the utilities-related areas of study.
Education	Foundation	SD Chamber of Commerce & Industry	Pierre	SD	$1,600	The purpose of this request is for a contribution from Xcel Energy to the 29th annual Youth Business Adventure (YBA) program. The mission of YBA is to provide the youth of South Dakota with the practical knowledge needed for their future in our economic
Education	Foundation	South Dakota 4-H Foundation, Inc	Brookings	SD	$4,000	This request supports the expansion of the 4-H Teens as Teachers Science Scholarship Program. The scholarship program engages older youth in teaching roles with elementary youth as an opportunity to "earn" a scholarship for post secondary education. With
Education	Foundation	South Dakota State University	Brookings	SD	$3,800	1. We request $2800 in support of the Center for Power Systems Studies 2. We request $1000 in support of an electrical engineer student scholarship.
Education	Foundation	Southeast Technical Institute Foundation	Sioux Falls	SD	$1,000	Provide scholarships to Southeast Technical Institute students who use Xcel Energy services in our region.
Education	Foundation	University of South Dakota School of Business	Vermillion	SD	$1,000	To provide a continued scholarship fund for our School of Business outstanding students in the region. Each year the School of Business goes through a rigorous process of review of the current business majors to identify students who are both outstanding
Education	Foundation	Volunteers of America, Dakotas	Sioux Falls	SD	$5,000	The agency is requesting funding for an intensive summer school program for economically disadvantaged youth at the agency's Floyd Career Learning Center. "Xcel in School" will improve students' basic skills in math and/or reading, enhance their study ski
Education Total					**$25,900**	
Grand Total					**$73,000**	

Program	Organization Name	MatchAmt	City	St.
Dollars for Doing	BOY SCOUTS OF AMERICA SIOUX COUNCIL	$35	SIOUX FALLS	SD
Dollars for Doing	Lennox Vol. Fire Dept.	$500	LENNOX	SD
Dollars for Doing Total		**$535**		
Higher Education	AUGUSTANA COLLEGE ASSOCIATION	$50	SIOUX FALLS	SD
Higher Education	AUGUSTANA COLLEGE ASSOCIATION	$50	SIOUX FALLS	SD
Higher Education	AUGUSTANA COLLEGE ASSOCIATION	$250	SIOUX FALLS	SD
Higher Education	AUGUSTANA COLLEGE ASSOCIATION	$175	SIOUX FALLS	SD
Higher Education	AUGUSTANA COLLEGE ASSOCIATION	$100	SIOUX FALLS	SD
Higher Education	AUGUSTANA COLLEGE ASSOCIATION	$250	SIOUX FALLS	SD
Higher Education	AUGUSTANA COLLEGE ASSOCIATION	$450	SIOUX FALLS	SD
Higher Education	AUGUSTANA COLLEGE ASSOCIATION	$50	SIOUX FALLS	SD
Higher Education	NORTHERN STATE UNIVERSITY FOUNDATION	$75	ABERDEEN	SD
Higher Education	OGLALA LAKOTA COLLEGE	$100	KYLE	SD
Higher Education	OGLALA LAKOTA COLLEGE	$150	KYLE	SD
Higher Education	FOUNDATION	$50	BROOKINGS	SD
Higher Education	FOUNDATION	$2,000	BROOKINGS	SD
Higher Education	FOUNDATION	$200	BROOKINGS	SD
Higher Education	FOUNDATION	$250	BROOKINGS	SD
Higher Education	FOUNDATION	$50	BROOKINGS	SD
Higher Education	FOUNDATION	$125	BROOKINGS	SD
Higher Education	FOUNDATION	$250	BROOKINGS	SD
Higher Education	FOUNDATION	$25	BROOKINGS	SD
Higher Education	FOUNDATION	$210	BROOKINGS	SD
Higher Education	FOUNDATION	$125	BROOKINGS	SD
Higher Education	FOUNDATION	$1,934	BROOKINGS	SD
Higher Education	UNIVERSITY OF SOUTH DAKOTA FOUNDATION	$25	VERMILLION	SD
Higher Education	UNIVERSITY OF SOUTH DAKOTA FOUNDATION	$100	VERMILLION	SD
Higher Education	UNIVERSITY OF SOUTH DAKOTA FOUNDATION	$200	VERMILLION	SD
Higher Education Total		**$7,244**		
Non-Profit-501c3	AMERICAN CANCER SOCIETY SIOUX FALLS SD	$50	SIOUX FALLS	SD
Non-Profit-501c3	AVERA MCKENNAN FOUNDATION	$50	SIOUX FALLS	SD
Non-Profit-501c3	CHILDRENS CARE HOSPITAL AND SCHOOL	$25	SIOUX FALLS	SD
Non-Profit-501c3	CHILDRENS CARE HOSPITAL AND SCHOOL	$25	SIOUX FALLS	SD
Non-Profit-501c3	CHILDRENS HOME SOCIETY OF SOUTH DAKOTA	$25	SIOUX FALLS	SD
Non-Profit-501c3	CHILDRENS HOME SOCIETY OF SOUTH DAKOTA	$500	SIOUX FALLS	SD
Non-Profit-501c3	CHILDRENS HOME SOCIETY OF SOUTH DAKOTA	$25	SIOUX FALLS	SD
Non-Profit-501c3	CHILDRENS HOME SOCIETY OF SOUTH DAKOTA	$100	SIOUX FALLS	SD
Non-Profit-501c3	CHILDRENS HOME SOCIETY OF SOUTH DAKOTA	$200	SIOUX FALLS	SD
Non-Profit-501c3	COMMUNITY FOOD BANK OF SOUTH DAKOTA	$25	SIOUX FALLS	SD
Non-Profit-501c3	FAMILY CONNECTION	$25	SIOUX FALLS	SD
Non-Profit-501c3	FAMILY CONNECTION	$25	SIOUX FALLS	SD
Non-Profit-501c3	SALVATION ARMY - Sioux Falls SD	$25	SIOUX FALLS	SD
Non-Profit-501c3	SALVATION ARMY SIOUX FALLS SD	$25	SIOUX FALLS	SD
Non-Profit-501c3	SOUTH DAKOTA COMMUNITY FOUNDATION	$200	PIERRE	SD
Non-Profit-501c3	The Banquet	$25	SIOUX FALLS	SD
Non-Profit-501c3	THE BANQUET	$25	SIOUX FALLS	SD
Non-Profit-501c3	UNION GOSPEL MISSION	$25	SIOUX FALLS	SD
Non-Profit-501c3	UNION GOSPEL MISSION	$25	SIOUX FALLS	SD
Non-Profit-501c3 Total		**$1,425**		
Grand Total		**$9,204**		

Name	Name City	State	Memo	Amount
Sioux Empire United Way, Inc.	Sioux Falls	SD	2008 UW Match	$14,884
United Way of the Black Hills	Rapid City	SD	2008 UW Match	$100
United Way				**$14,984**

Program	FLName	City	State	Grant	BriefPurpose
Community	Alzheimer's Association	Sioux Falls	SD	$250	Memory Walk
Community	American Cancer Society	Dell Rapids	SD	$250	Relay for Life in Dell Rapids, SD
Community	American Legion Auxiliary	Sioux Falls	SD	$100	Sponsor Girls State
Community	The American Legion	Sioux Falls	SD	$150	Sponsor Boys State
Community	American Red Cross	Sioux Falls	SD	$1,000	Business Disaster Program
Community	Avera McKennan Foundation	Sioux Falls	SD	$1,000	Race Against Breast Cancer
Community	Berakhah House	Sioux Falls	SD	$250	Money for operating budget
Community	Canton Volunteer Fire Department	Canton	SD	$100	Operating Budget
Community	Christian Center Elementary	Sioux Falls	SD	$100	Donation for benefit auction
Community	City of Baltic	Baltic	SD	$150	Dog Days of Summer
Community	Dell Rapids Chamber of Commerce	Dell Rapids	SD	$200	Boyer Station
Community	El Riad Shrine Circus	Sioux Falls	SD	$180	Tickets too Circus for elementary students
Community	Garretson Volunteer Fire Department	Garretson	SD	$250	Operating budget
Community	Howard Wood Dakota Relays	Wentworth	SD	$100	Howard Dakota Relays
Community	Junior Achievement of South Dakota, Inc.	Sioux Falls	SD	$250	Start JA Personal Finance program to high school students in Lennox, SD
Community	Inc.	Sioux Falls	SD	$2,800	Classrooms for 2009
Community	Juvenile Diabetes Research Foundation	Sioux Falls	SD	$2,500	Walk to Cure Diabetes
Community	Lennox Volunteer Fire Department	Lennox	SD	$100	Operating budget
Community	National Kidney Foundation	Sioux Falls	SD	$1,000	Kidney Walk fundraiser sponsor
Community	Salem Volunteer Fire Department	Salem	SD	$100	Operating budget
Community	Sanford Medical Center	Sioux Falls	SD	$250	Acoustic Christmas
Community	SculptureWalk	Sioux Falls	SD	$2,118	Lease two sculptures
Community	Sioux Council Boy Scouts	Sioux Falls	SD	$100	Friends of Scouting campaign
Community	Sioux Council Boy Scouts	Sioux Falls	SD	$100	Friends of Scouting
Community	Sioux Empire Home Builders	Sioux Falls	SD	$1,000	Ronald McDonald House
Community	Sioux Falls Ducks Unlimited	Sioux Falls	SD	$325	Annual banquet
Community	Sioux Falls Firefighters	Sioux Falls	SD	$500	Firefighter Combat Challenge
Community	Sioux Falls Literacy Council	Sioux Falls	SD	$250	Sponsor 11th annual Literacy Breakfast
Community	Sioux Rise Lions Club	Sioux Falls	SD	$150	2008 Fundraiser
Community	South Dakota Voices for Children	Sioux Falls	SD	$2,500	Champion for Children Awards
Community	South Sioux Falls Kiwanis Club	Sioux Falls	SD	$150	Sponsor annual Roast Beef Dinner
Community	University of Sioux Falls	Sioux Falls	SD	$1,700	Science for Success campaign
				$19,973	

2009 SD Electric Rate Case Expenses		**SOUTH DAKOTA JURISDICTION**
Consulting Fees		$ 100,000
Rate of Return - Concentric Energy Advisors		
Revenue Analysis Support - Moss & Barnett		
Outside Legal Fees		175,000
Moss & Barnett		
David A. Gerdes		
State Filing Fees		150
Administrative Costs (transcripts, admin)		18,099
Sub - TOTAL		**$ 293,249**
Remove percent for unregulated business (.2505%)	-0.2505% $ 293,249	($735)
TOTAL		**$ 292,514**

Energy Production Projects (EP)

Cycle	Total Projects	North Dakota Projects	% ND Projects	South Dakota Projects	% SD Projects	Total Awarded	North Dakota Awards	% ND Awards	South Dakota Awards	% SD Awards
1	8	0	0%	0	0%	$9,782,835	$0	0%	$0	0%
2 (*)	11	0	0%	0	0%	$23,415,901	$0	0%	$0	0%
3 (**)	5	1	20%	0	0%	$8,218,402	$2,000,000	24%	$0	0%
Total EP	**24**	**1**	**4%**	**0**	**0%**	**$41,417,138**	**$2,000,000**	**5%**	**$0**	**0%**

Research/Development Projects (RD)

Cycle	Total Projects	North Dakota Projects	% ND Projects	South Dakota Projects	% SD Projects	Total Awarded	North Dakota Awards	% ND Awards	South Dakota Awards	% SD Awards
1	11	3	`	0	0%	$6,247,566	$1,754,620	28%	$0	0%
2	18	1	6%	0	0%	$12,804,466	$999,995	8%	$0	0%
3	17	4	24%	1	6%	$14,397,817	$3,969,277	28%	$493,608	3%
Total RD	**46**	**8**	**17%**	**1**	**6%**	**$33,449,849**	**$6,723,892**	**20%**	**$493,608**	**1%**
Grand Total	**70**	**9**	**13%**	**1**	**1%**	**$74,866,987**	**$8,723,892**	**12%**	**$493,608**	**1%**

Project Detail

Grant	Grantee	State	Award	Cycle	Type
BB-09	University of North Dakota - Cofiring	ND	$444,478	1	Biomass
BB-12	University of North Dakota - SCR Performance	ND	$60,000	1	Biomass
CB-08	University of North Dakota - SOFC	ND	$1,250,142	1	Biomass
RD-34	University of Florida (***)	ND	$999,995	2	Biomass
RD3 - 63	Community Power Corporation (****)	ND	$999,926	3	Biomass
RD3 - 66	University of North Dakota	ND	$999,065	3	Biomass
RD3 - 68	University of North Dakota	ND	$970,558	3	Biomass
RD3 - 71	University of North Dakota	ND	$999,728	3	Biomass
RD3-21	Northern Plains Power Technology	SD	$493,608	3	Solar

(*) Includes $10 M Awarde to Excelsior Energy by the MPUC
(**) American Cyrstal Sugar Company was awarded $2 M. Since the award, ACSC has chosen to decline the RDF grant to pursue other uses of the planned methane production at the plant.
(***) Project includes two Fargo based engineering consultants for American Crystal Sugar Corporation, Moorhead, MN, which is the project host for the demonstration.
(****) Project includes 6 months of testing at Federal Machine, West Fargo, ND .

RDF AWARDS
North Dakota and South Dakota Project Descriptions

Cycle 1

Research/Development Projects:
University of North Dakota, Grand Forks, ND, Impacts of Biomass Cofiring on the Operation of a Next-Generation Power System, $444,478.
University of North Dakota, Grand Forks, ND, Biomass Impacts of SCR Performance, $60,000.
University of North Dakota, Grand Forks, ND, Development and Testing of an Solid Oxide Fuel Cell Gasification System, $1,250,142.

Cycle 2

Research/Development Projects:
University of Florida and American Crystal Sugar East Grand Forks, Minn., to research the conversion of biomass into energy and compost through sequential batch anaerobic composting, $999,995. The Prairie Island Indian Community sponsored this project.

Cycle 3

Energy Production Projects:
American Crystal Sugar Co., Moorhead, Minn., to design, develop and construct a 3-megawatt electricity cogeneration plant utilizing methane, which currently is produced as a result of sugar beet processing. The cogeneration facility will be integrated with the company's current biogas collection system, $2 million.

Research/Development Projects:
Community Power Corp., Littleton, Colo., to adapt current proven modular biopower technology to produce and demonstrate a biomass/natural gas hybrid (dual fuel) power generation system. The system will integrate with on-site electrical and thermal loads to deliver electricity and heat, $999,926.

University of North Dakota, Grand Forks, N.D., to demonstrate the performance of a mobile integrated indirect wet biomass liquefaction system gasifier at one-fourth commercial scale, $999,065.

University of North Dakota, Grand Forks, N.D., to test and develop a novel biotechnology additive to convert biomass into biogas, $970,558.

University of North Dakota, Grand Forks, N.D., to develop an economical biomass power system by combining previous bench scale work in thermally integrated gasification systems with developmental work on a low-Btu gas turbine, $999,728.

Northern Plains Power Technology from Brookings, S.D. was awarded a $493,608 RDF 3rd cycle grant to develop technologies for loss-of-mains detection based on a) power system harmonic signatures, and b) synchrophasor data transmitted by utility broadband communications. Loss-of-mains detection is a significant problem for small-distributed generators, such as small wind power and photovoltaic systems. The overall goal of the Project is to determine the feasibility of two new methods for loss-of-mains detection by distributed energy resources ("DERs"): detection based on changes in harmonic signatures, or detection based on changes in the relationship between synchrophasors. Achievement offering this goal will allow DERs to a) be a more cost-effective means for meeting customer demand, and b) assume more of a grid-support role.

($000's)

		Pro Forma 2008					
		Total Utility			South Dakota Jurisdiction		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Adjusted (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	Adjusted (F) (D) + (E)
	Electric Plant as Booked						
1	Production	$6,042,048	$634,461	$6,676,509	$310,249	$32,574	$342,823
2	Transmission	1,513,273	93,680	1,606,953	77,477	4,810	82,287
3	Distribution	2,765,894	8,185	2,774,079	166,887	8,185	175,072
4	General	249,321	9,338	258,659	13,458	539	13,997
5	Common	383,941	0	383,941	21,141	0	21,141
6	TBT Investment	0	0	0	0	0	0
7	TOTAL Utility Plant in Service	$10,954,477	$745,664	$11,700,141	$589,212	$46,108	$635,320
	Reserve for Depreciation						
8	Production	$3,964,255	$25,661	$3,989,916	$203,329	$1,318	$204,647
9	Transmission	523,708	2,740	526,448	26,826	141	26,967
10	Distribution	1,068,759	315	1,069,074	65,333	314	65,647
11	General	93,882	757	94,639	5,091	45	5,136
12	Common	211,215	0	211,215	11,690	0	11,690
13	TOTAL Reserve for Depreciation	$5,861,819	$29,473	$5,891,292	$312,270	$1,818	$314,088
	Net Utility Plant in Service						
14	Production	$2,077,793	$608,800	$2,686,593	$106,920	$31,256	$138,176
15	Transmission	989,565	90,940	1,080,505	50,651	4,669	55,320
16	Distribution	1,697,135	7,870	1,705,005	101,554	7,871	109,425
17	General	155,439	8,581	164,020	8,367	494	8,861
18	Common	172,726	0	172,726	9,451	0	9,451
19	TBT Investment	0	0	0	0	0	0
20	Net Utility Plant in Service	$5,092,658	$716,191	$5,808,849	$276,942	$44,290	$321,232
21	Utility Plant Held for Future Use	$0	$0	$0	$0	$0	$0
22	Construction Work in Progress	$0	$0	$0	$0	$0	$0
23	Less: Accumulated Deferred Income T	$855,388	$103,559	$958,947	$49,023	$6,770	$55,793
24	Cash Working Capital	$36,870	($7,058)	$29,812	$2,279	($413)	$1,866
	Other Rate Base Items:						
25	Materials and Supplies	$94,856	$0	$94,856	$4,944	$0	$4,944
26	Fuel Inventory	111,084	0	111,084	5,879	0	5,879
27	Non-Plant Assets & Liabilities	(121,267)	72,362	(48,905)	(6,518)	3,881	(2,637)
28	Prepayments	20,275	0	20,275	4,942	0	4,942
29	Configuration Management	0	85	85	0	85	85
30	Interest on Customer Deposits	(1,079)	0	(1,079)	(63)	0	(63)
31	Nuclear Outage - Change of Accting	19,253	17,871	37,124	987	916	1,903
32	Customer Advances	(206)	0	(206)	(15)	0	(15)
33	Other Working Capital	5,063	0	5,063	297	0	297
34	Total Other Rate Base Items	$127,979	$90,318	$218,297	$10,453	$4,882	$15,335
35	Total Average Rate Base	$4,402,119	$695,892	$5,098,011	$240,651	$41,989	$282,640

($000's)

		Pro Forma 2008					
		Total Utility			South Dakota Jurisdiction		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Adjusted (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	Adjusted (F) (D) + (E)
	Accumulated Deferred Income Taxes						
1	Production	$325,529	$52,163	$377,692	$19,109	$2,705	$21,814
2	Transmission	161,013	19,738	180,751	8,234	1,013	9,247
3	Distribution	357,644	2,756	360,400	21,021	1,502	22,523
4	General	22,170	0	22,170	1,213	0	1,213
5	Common	32,927	0	32,927	1,821	0	1,821
6	TBT Investment	4	0	4	0	0	0
7	Non-Plant Related	(43,899)	28,902	(14,997)	(2,375)	1,550	(825)
11	TOTAL Accum Deferred Income Taxes	$855,388	$103,559	$958,947	$49,023	$6,770	$55,793

Test Year Ending December 31, 2008
($000's)

Line No.	Description	2006 Actual (A)	General Rate Case Filing Docket No. EL09-____ (B)	Change (C) = (B) - (A)
	Electric Plant as Booked			
1	Production	$273,567	$342,823	$69,256
2	Transmission	60,265	82,287	22,022
3	Distribution	152,822	175,072	22,250
4	General	9,625	13,997	4,372
5	Common	21,342	21,141	(201)
6	TBT Investment	0	0	0
7	TOTAL Utility Plant in Service	$517,621	$635,320	117,699
	Reserve for Depreciation			
8	Production	$199,461	$204,647	$5,186
9	Transmission	24,005	26,967	2,962
10	Distribution	57,635	65,647	8,012
11	General	4,339	5,136	797
12	Common	10,942	11,690	748
13	TOTAL Reserve for Depreciation	$296,383	$314,088	$17,705
	Net Utility Plant in Service			
14	Production	$74,106	$138,176	$64,070
15	Transmission	36,260	55,320	19,060
16	Distribution	95,187	109,425	14,238
17	General	5,286	8,861	3,575
18	Common	10,400	9,451	(949)
19	TBT Investment	0	0	0
20	Net Utility Plant in Service	$221,238	$321,232	$99,994
21	Utility Plant Held for Future Use	$0	$0	$0
22	Construction Work in Progress	$0	$0	$0
23	Less: Accumulated Deferred Income Taxes	$45,992	$55,793	$9,801
24	Cash Working Capital	$0	$1,866	$1,866
	Other Rate Base Items:			
25	Materials and Supplies	$4,939	$4,944	$5
26	Fuel Inventory	1,763	5,879	4,116
27	Non-Plant Assets & Liabilities	(6,171)	(2,637)	3,534
28	Prepayments	5,251	4,942	(309)
29	Configuration Management	199	85	(114)
30	Interest on Customer Deposits	(51)	(63)	(12)
31	Nuclear Outage - Change of Accting	0	1,903	1,903
32	Customer Advances	0	(15)	(15)
33	Other Working Capital	0	297	297
34	Total Other Rate Base Items	$5,929	$15,335	$9,406
35	Total Average Rate Base	$181,175	$282,640	$101,465

Northern States Power Company, a Minnesota corporation
Electric Utility - State of South Dakota
DETAILED RATE BASE COMPONENTS
Test Year Ending December 31, 2008
($000's)

Line No.	Description	2006 Actual	2008 Test Year Unadjusted	2008 Pro Forma Adjusted
	Electric Plant as Booked			
1	Production	$273,567	$310,249	$342,823
2	Transmission	60,265	77,477	82,287
3	Distribution	152,822	166,887	175,072
4	General	9,625	13,458	13,997
5	Common	21,342	21,141	21,141
6	TBT Investment	0	0	0
7	TOTAL Utility Plant in Service	$517,621	$589,212	$635,320
	Reserve for Depreciation			
8	Production	$199,461	$203,329	$204,647
9	Transmission	24,005	26,826	26,967
10	Distribution	57,635	65,333	65,647
11	General	4,339	5,091	5,136
12	Common	10,942	11,690	11,690
13	TOTAL Reserve for Depreciation	$296,383	$312,270	$314,088
	Net Utility Plant in Service			
14	Production	$74,106	$106,920	$138,176
15	Transmission	36,260	50,651	55,320
16	Distribution	95,187	101,554	109,425
17	General	5,286	8,367	8,861
18	Common	10,400	9,451	9,452
19	TBT Investment	0	0	0
20	Net Utility Plant in Service	$221,238	$276,942	$321,232
21	Utility Plant Held for Future Use	$0	$0	$0
22	Construction Work in Progress	$0	$0	$0
23	Less: Accumulated Deferred Income Taxes	$45,992	$49,023	$55,793
24	Cash Working Capital	$0	$2,279	$1,866
	Other Rate Base Items:			
25	Materials and Supplies	$4,939	$4,944	$4,944
26	Fuel Inventory	1,763	5,879	5,879
27	Non-Plant Assets & Liabilities	(6,171)	(6,518)	(2,637)
28	Prepayments	5,251	4,942	4,942
29	Configuration Management	199	0	85
30	Interest on Customer Deposits	(51)	(63)	(63)
31	Nuclear Outage - Change of Accting	0	987	1,903
32	Customer Advances	0	(15)	(15)
33	Other Working Capital	0	297	297
34	Total Other Rate Base Items	$5,929	$10,453	$15,335
35	Total Average Rate Base	$181,175	$240,651	$282,640