EXHIBIT
PENGAD 800-631-6989
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Direct Testimony and Schedules
Anne E. Heuer

Before the North Dakota Public Service Commission
State of North Dakota

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

For Authority to Increase Rates for Electric Utility
Service in North Dakota

Case No. PU-07-776
Exhibit 20

Overall Revenue Requirements
Rate Base
Income Statement

December 7, 2007

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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").

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have over thirty-two years of employment experience with Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company"). 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 Xcel Energy, operating in North Dakota.

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

A. I will provide testimony supporting the Company's financial data and its Notice of Change in Rates for Electric Service (the "Notice") for the State of North Dakota retail electric jurisdiction. My testimony addresses the North Dakota jurisdiction's retail electric operations' overall retail revenue requirement of $167,714,000 and revenue deficiency of $20,535,000, determined by the cost of service for the 2008 budget test year.

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

A. Yes they were.

II. DATA PROVIDED AND SELECTION OF TEST YEAR

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

A. Financial data is provided for the most recent fiscal year, that being calendar year 2006, and the test year selected, calendar year 2008.

Financial data for the most recent fiscal year and the test year are adjusted for traditional regulatory adjustments (*e.g.* advertising expenses, economic development, etc.). The test year on which the Notice is based starts with financial data included in the Company's 2008 projected fiscal year budget, and includes ratemaking adjustments deemed necessary, along with refinements and corrections to 2008 budgeted data. These changes to the base data were made to assure appropriateness for purposes of developing a test year that provides a normalized level of rate base and expenses to establish just and reasonable rates. Separate rate base and income statement bridge schedules that identify test period adjustments are provided with my testimony as Exhibit__(AEH-1), Schedule 5.

Q. HOW DID THE COMPANY SELECT THE PROPOSED TEST YEAR FOR THIS PROCEEDING?

A. Calendar year 2008 was selected as the test year for this filing using Xcel Energy's first-year budget data. The test year is based on the most recent available budget information that is deemed appropriate for ratemaking purposes.

Q. DOES THE 2008 PROJECTED TEST YEAR MEET THE COMMISSION'S REQUIREMENTS?

A. Yes. The use of a projected test year is consistent with the intent of North Dakota Century Code ("NDCC") § 49-04-04.1, subd. 2, which requires the Company to present:

(a) a comparison of forecast data to historical period data to demonstrate the reliability and accuracy of the utility's forecast including a comparison of the prior years' forecast or budgeted data to actual data for those periods;

(b) a statement that the test year budget data is reasonable, reliable, and made in good faith and all basic assumptions used in making or supporting the forecast are reasonable, evaluated, identified, and justified to allow the Commission to test the appropriateness of the forecast; and

(c) the accounting treatment applied to anticipated events and transactions in the budget is the same as the accounting treatment to be applied in recording the events once they have occurred.

I provide a comparison of past budgets to actual costs later in my testimony in compliance with the first requirement of this statute. The 2008 Company budget data, as adjusted for the known and measurable changes discussed below, is a reasonable representation of the costs and rate case expense the Company will incur to provide electric service in the State of North Dakota, and complies with NDCC § 49-05-04.1, subd. 2. Thus, the 2008 test year data is reasonable, reliable and made in good faith and is appropriate for setting rates in this proceeding. In addition, the accounting treatment applied to anticipated events and transactions in the budget is the same as the accounting treatment applied in recording the events once they have occurred.

Q. NDCC § 49-05-04.1, Subd. 1(b) REQUIRES A UTILITY TO FILE "HISTORIC PERIOD" DATA. HOW IS XCEL ENERGY COMPLYING WITH THIS REQUIREMENT?

A. Schedule 2 to my testimony is the Company's 2006 actual jurisdictional summary data. This information has been updated from the information underlying the financial statements in our May 1, 2007 jurisdictional annual report filed with the Commission.

Q. PLEASE EXPLAIN WHY IT WAS NECESSARY TO UPDATE THE 2006 ACTUAL JURISDICTIONAL INFORMATION PROVIDED TO THE COMMISSION IN MAY 2007?

A. In July of 2007, a data error was discovered relative to data included in the 2006 actual 12 coincident peak demand allocators ("demand allocators"). The error occurred in the South Dakota jurisdictional data recorded during the last quarter of 2006. The demand allocators are used to allocate fixed production and transmission investments and expenses. The North Dakota jurisdictional demand factors used to prepare the May 1 report were 6.0657 percent for Production investment and expenses and 5.9493 percent for Transmission investment and expenses. The Company corrected the data and recalculated the 2006 actual demand allocators for the total operating utility company (the "Company"). The corrected factors for the North Dakota electric retail jurisdiction are 6.0176 percent for Production investment and expenses and 5.9020 percent for Transmission investment and expenses, a decrease of 0.0481 percent and 0.0473 percent, respectively.

Q. WHAT EFFECT DID THIS CHANGE IN DEMAND HAVE ON THE 2006 NORTH DAKOTA ELECTRIC JURISDICTIONAL RESULTS?

A. After applying the corrected factors for this minor difference in North Dakota demand, the overall North Dakota jurisdictional revenue deficiency fell by $186,000 to $5,376,000.

III. TEST YEAR BUDGET DEVELOPMENT

Q. DESCRIBE THE TEST YEAR BUDGET PROCESS.

A. The budgeting process for the 2008 test year began in early March 2007 with the issuing of Budget Guidelines and Instructions to the various business areas for the 2008 budget preparation. The test year budget is assembled separately by its various components: Sales Forecast (customers and consumption), Retail and Other Revenues, Cost of Production, Operating and Maintenance ("O&M") Expenses, Capital Invested, Other Rate Base Investment and Capital Structure Components. The various budgets are submitted to the Finance Council for review. All final O&M, labor and capital expenditure budgets are submitted to the Board of Directors for review and approval. Management will use the final budget, as approved, to monitor and manage the Company's operations and financial performance during 2008.

Q. DESCRIBE HOW COSTS FOR THE NORTH DAKOTA JURISDICTIONAL ELECTRIC OPERATIONS ARE DEVELOPED IN THE BUDGET PROCESS.

A. Costs from the Service Company are typically either directly assigned or allocated to the particular Xcel Energy operating company (here the Company) and then further assigned or allocated to specific utility operations and jurisdiction.

Each business area is responsible for appropriate Federal Energy Regulatory Commission ("FERC") designation of its budgeted O&M dollars. Accounting codes in the J.D. Edwards ("JDE") general ledger accounting system determine the FERC account to which budgeted costs apply. Each JDE business unit contains the necessary information to determine the appropriate FERC account classification. In addition, the business areas are responsible for including a location code where appropriate. This information helps facilitate appropriate utility and jurisdictional cost assignment.

Q. YOU MENTIONED THAT YOU MADE ADJUSTMENTS TO THE 2008 BUDGET FOR CERTAIN TRADITIONAL REGULATORY ADJUSTMENTS. PLEASE DESCRIBE THESE ADJUSTMENTS.

A. I made the following adjustments to the 2008 Budget to comply with the traditional regulatory adjustments made by the Commission. Those adjustments are:

1) Advertising Expenses
2) Economic Development Costs
3) Interest on Customer Deposits
4) Professional Association and Utility Association Dues

Q. DID YOUR ANALYSIS OF THE O&M, LABOR AND CAPITAL BUDGETS REQUIRE THAT ADDITIONAL ADJUSTMENTS BE MADE TO OBTAIN A TEST YEAR BUDGET FOR RATE CASE PRESENTATION?

A. Yes. As part of the preparation of any rate case, an additional level of internal review of budget data is undertaken. The underlying financial operation and capital data was scrutinized for anomalies and errors. During the process of evaluating the data, a few coding errors, inconsistencies, and misclassifications were discovered and appropriate adjustments were made to the test year.

Q. PLEASE LIST THE TYPES OF ADJUSTMENTS MADE AS A RESULT OF THE DATA REVIEW PROCEDURE.

A. The adjustments made to the initial budget data included:

1) Other Operating Revenue Adjustments – Interchange decommissioning revenue related to Northern States Power Company, a Wisconsin corporation ("NSP-Wisconsin") was included as part of the Company's 2008 Budget. However, since the costs related to these revenues are budgeted at the jurisdictional level (NSP-Wisconsin), these revenues are not related to the Company, or the State of North Dakota electric jurisdiction and were, therefore, adjusted to be excluded from other electric operating revenue. In addition to this adjustment, there were two other adjustments to include unbudgeted Midwest Independent System Operator ("MISO") network delivery revenue. Specifically, these two adjustments were for the new MISO Schedule 2 reactive supply and voltage control/generation sources service and the unbundled revenue related to transmission deliveries to Wisconsin municipal customers

(termed MISO Network Revenue Adj. on Exhibit ___(AEH-1) Schedule 3).

2) King Chemicals Adjustment – The 2008 O&M budget included only the North Dakota, South Dakota, Wholesale and NSP-Wisconsin portion of costs for the chemicals needed to run the newly installed pollution control equipment at the Company's A. S. King generating plant. Because the Minnesota Public Utilities Commission ("MPUC") granted deferred accounting for the Minnesota portion of these costs in Docket No. E002/M-06-1315, the Minnesota portion of the total cost was budgeted to a deferred account rather than to an O&M account. The process used to allocate the remaining King chemical costs to all of the Company's jurisdictions, including Minnesota. Because no costs should have been allocated to Minnesota, an adjustment was made to correct the cost assignment.

3) Tree Trimming Adjustment – The processes used to assign distribution costs to the appropriate jurisdiction utilizes a code attached to the budget account to determine the jurisdictional cost assignment. We discovered a coding error during our data review process that inadvertently assigned the tree trimming budgeted for the North Dakota jurisdiction to South Dakota. Therefore, an adjustment was made to exclude the cost from South Dakota expense and include the cost in North Dakota jurisdictional distribution expense.

4) MISO Schedule 16 and 17 Reclassification between FERC accounts – During the data review process we discovered that MISO Schedule 16 and 17 Day 2 administrative expenses were budgeted to FERC account 565 (Transmission of Electricity by Others), rather than FERC Account 575.7 (Market Administration, Monitoring and Compliance Services).

These costs were moved to the appropriate FERC Account for rate case processing.

5) Remaining Life Adjustment - As a part of the Company's 2007 Annual Review of Remaining Lives filing with the MPUC, the Company requested approval of an extended life for the Monticello nuclear generating plant, as well as changes to several other small generating facilities. At the time the 2008 capital budget was prepared, there had not yet been a decision from the MPUC granting approval of the Company's request. Therefore, the budget was prepared assuming an effective date of January 1, 2008 for the extended lives of these facilities. However, on September 21, 2007 the MPUC issued its order approving the change in remaining lives effective January 1 2007. To correct the 2008 beginning balances to reflect the implementation of the MPUC order, we reduced the accumulated reserve for depreciation for Monticello by $1,490,000 and the other plants by $45,000 for the North Dakota jurisdiction. In addition, we increased the accumulated deferred income taxes for Monticello by $609,000 and the other plants by $18,500 for the North Dakota jurisdiction.

Q. DO YOU HAVE A SCHEDULE THAT IDENTIFIES THE TRADITIONAL REGULATORY ADJUSTMENTS AND THE ADJUSTMENTS THAT RESULTED FROM THE REVIEW OF THE PROJECTED YEAR BUDGETED DATA?

A. Yes. Exhibit___(AEH-1), Schedule 3 provides a list of the traditional regulatory adjustments and the associated amounts for the 2008 budget along with the data review adjustments discussed above.

Q. ONCE YOU COMPLETED THESE INITIAL ADJUSTMENTS TO THE BUDGET BASE DATA, DID YOU FURTHER ADJUST THE BASE DATA TO DEVELOP THE TEST YEAR?

A. Yes. I made a number of test period adjustments that affected either the rate base or the income statement. A list of these test period adjustments is shown on Exhibit___(AEH-1), Schedule 4. I will also discuss each adjustment later in my testimony. In addition, I have provided a bridge schedule (Exhibit___(AEH-1), Schedule 5) that shows all adjustments included in Exhibit___(AEH-1), Schedule 3 and Exhibit___(AEH-1), Schedule 4.

Q. PLEASE DESCRIBE WHETHER THE COMPANY'S BUDGETING PROCESS IS CONSISTENT WITH PREVIOUS BUSINESS PRACTICES AND WHETHER THAT PROCESS PROVIDES REASONABLE RESULTS?

A. The budgeting process is consistent with past business practice and has provided accurate forecasts of actual costs and revenues in the past. Except for the immediate post-merger period (2001-2002), over the past six years the budgeting process has produced a reasonable forecast of the expected outcome for electric utility operations. Exhibit___(AEH-1), Schedule 6 is a comparative graph of actual O&M expense results with budget projections for each of the five years, 2002 through 2006. In 2002, these numbers varied somewhat from normal deviations due to processes necessary to fully integrate post-merger information and systems. The 2003 - 2006 information illustrates how the historical correlation between budgeted and actual O&M expenses has been reinstated once the merger process was completed.

Q. IS THE 2008 O&M EXPENSE BUDGET FOR THE ELECTRIC UTILITY OPERATIONS AN ACCURATE AND RELIABLE PROJECTION?

A. Yes. With the adjustments I previously described, it is a reasonable projection on which to base this request for rate relief.

Q. HAVE THERE BEEN ORGANIZATIONAL AND OTHER CHANGES THAT HAVE AFFECTED THE JURISDICTIONAL ASSIGMENTS AND ALLOCATIONS?

A. Yes, there have also been some organizational changes since 2005 that change which JDE accounts will incur electric utility operation costs. The wires and pipes portion of Xcel Energy's Customer and Field Operations ("C&FO") business area, along with Government and Regulatory Affairs, is now consolidated in the Company's Utility Group. Business Systems and the Customer Care group of C&FO is now part of Customer Enterprise Solutions.

Q. WHY HAVE YOU COMPARED THE CURRENT ORGANIZATION TO THE ORGANIZATION AS IT EXISTED IN 2005?

A. 2005 is the last year in which the Company earned its authorized return on equity. Therefore, whenever I discuss in my testimony the changes that may have affected the revenue requirement, I will use 2005 as the base year.

IV. TEST YEAR REVENUE DEFICIENCY

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

A. The jurisdictional retail revenue requirement for North Dakota electric utility operations is $167,714,000 based on average rate base and projected net operating income for the 2008 test year, the average capital structure, short-term debt, long-term debt and 11.5 percent cost of equity, based on the return on equity recommended by Dr. James Vander Weide in his Direct Testimony filed with this Notice.

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

A. The amount of the revenue deficiency for the test year is $20,535,000. A summary of the revenue deficiency is shown in Exhibit___(AEH-1), Schedule 7 as a comparison of the jurisdictional revenue requirement amount for the test year with the forecasted revenues for the same period under present rates which were approved by the Commission in Case No. PU-400-92-399. The level of North Dakota retail electric rates must be increased by this amount in order to earn an overall return on rate base of 9.20 percent as developed in Exhibit __ (AEH-1), Schedule 8, page 5.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CAPITAL STRUCTURE AND WHAT ARE THE VARIOUS COMPONENTS?

A. The capital structure employed in this case represents the Company's 2008 budgeted amounts. The costs and ratios associated with this capital structure are found in Exhibit __ (AEH-1), Schedule 8, page 5, and are as follows:

	Rate	Ratio	Weighted Cost
Long Term Debt	6.79%	45.61%	3.10%
Short Term Debt	5.74%	2.62%	0.15%
Common Equity	11.50%	51.77%	5.95%
Weighted Cost			9.20%

These capital structure ratios and the cost rates are based on the 2008 budget for the Company's capital structure.

Q. IS THE COMPANY A SEPARATE CORPORATION WITH ITS OWN CAPITAL STRUCTURE?

A. Yes. The Company is a legally separate corporation that is a wholly owned subsidiary of Xcel Energy Inc. The Company is not simply a division of a larger corporation. The Company has its own, separate capital structure that consists of common equity, long-term debt and short-term debt. It has no preferred stock in its capital structure. The use of the Company's legally separate capital structure reflects the sources of capital that have been used to finance its electric utility operations.

Q. DOES THE COMPANY ISSUE ITS OWN DEBT TO THE PUBLIC?

A. Yes. The Company currently has approximately $2.7 billion of separately issued and publicly traded long-term debt securities outstanding. The Company also incurs its own short-term debt.

Q. IS THE COMPANY'S SEPARATE CAPITAL STRUCTURE SIGNIFICANT TO ITS COST OF DEBT?

A. Yes. The Company files annual and quarterly 10K and 10Q statements with the Securities and Exchange Commission ("SEC"). These SEC filings disclose and reflect the Company's actual capital structure. The Company's actual capital structure is significant to its financial risk. Investors in the Company's publicly traded debt securities and the credit rating agencies have relied on the Company's actual capital structure, as reflected in these SEC filings. As a result, the use of the combination of: (i) the Company's separate capital structure; and (ii) the Company's separate costs of long-term debt and short-term debt is supported by the regulatory principle of matching.

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

A. The revenue deficiency amount represents a 13.95 percent overall increase in retail revenues from base rates compared to projected retail revenues at present rates.

Q. DID YOU PREPARE A COST OF SERVICE STUDY THAT SUPPORTS THE REVENUE REQUIREMENT AMOUNT AND REVENUE DEFICIENCY FOR THE TEST YEAR?

A. Yes, under my direction, a cost of service study was prepared. Exhibit___(AEH-1), Schedule 8 contains a copy of the jurisdictional cost of service study.

Q. WHAT ARE THE MAJOR CAUSES OF THE COMPANY'S NEED FOR RATE RELIEF?

A. A summary of the cost elements to which the revenue deficiency can be attributed is provided in Exhibit___(AEH-1), Schedule 9. The major cost elements driving the revenue deficiency are related to: 1) the growth in rate base and the capital recovery requirements associated with the additional rate base investments made since the 2005 actual year; and 2) increases in operating and maintenance costs due to higher nuclear operating expenses, purchased demand costs, distribution expense, refined jurisdictional cost assignments, inflation, and wage increases. Another significant element of the revenue deficiency is related to shifting the wholesale margins from being a credit to the base revenue requirement to being a credit to the fuel cost revenue requirement.

Q. WHAT HAVE BEEN THE MAIN REASONS FOR GROWTH IN THE COMPANY'S GENERATION PLANT INVESTMENT?

A. As described in Mr. Kent Larson's Direct Testimony, the Company has made several new plant investments:

- Rehabilitation of the A. S. King Generating Plant at a cost of approximately $480.2 million.
- The repowering of the High Bridge Generating Plant with the installation of a new combined cycle plant, with an approximate cost upon completion of $388.5 million.
- A combined cycle generation facility at the Company's Black Dog plant, placed into service at a cost of $112.8 million.
- Several peaking plants, such as the Blue Lake Units 7 and 8, and Angus C. Anson Unit 4, placed into service in 2005 at a combined cost of $103.5 million.

Q. IS THERE A NEW GENERATION PLANT EXPECTED TO COME ON LINE IN 2008 THAT IS INCLUDED IN THE TEST YEAR RATE BASE?

A. Yes. The Company is investing in the 100 MW Grand Meadow Wind Farm ("Wind Farm") located in Mower County, Minnesota. On June 25, 2007 the Company filed a Certificate of Need application with the MPUC (Docket No. E002/CN-07-873), seeking approval of, and justifying the need for, this project. We expect to receive approval from the MPUC during the last quarter of 2007 or early in 2008. The Company has contracted with enXco Development Corporation to build this 100 MW Wind Farm on a 200 MW site under development by enXco. The Wind Farm is expected to consist of

67, 1.5 MW wind turbines over approximately 40 square miles and is expected to be in service by the end of 2008 at a total cost of approximately $ 223.8 million.

Q. WHAT INCREASE HAS THERE BEEN IN THE COMPANY'S TRANSMISSION PLANT INVESTMENT?

A. As described in Mr. Walter Grivna's Direct Testimony, the Company has made significant investment in transmission plant in three separate groups: system performance, generation investments and wind supporting transmission investments. Exhibit 1 to Mr. Grivna's Direct Testimony breaks out the amount of investment in each category for the period 2004 through 2008. In total, the Company added approximately $484.3 million in transmission investment since the 2005 actual year, resulting in an increase in rate base of approximately $21.4 million for the North Dakota jurisdiction.

Q. WHAT ARE THE ELEMENTS OF CAPITAL RECOVERY?

A. The elements of capital recovery are: (i) depreciation, which is the ratable return of investment over its estimated service life; (ii) return on investment; and (iii) related income taxes. Depreciation expense has increased by $1,226,000 since 2005. This expense is driven by the increase in utility plant investment, including significant investment in our generating facilities and transmission system. The increase in Depreciation expense related to the increase in utility plant is partially offset by the extended life of our Monticello nuclear generating plant. Since 2005, utility plant in-service investment allocated to the North Dakota jurisdiction has increased by over $98.4 million.

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 MPUC extended the life of the Monticello nuclear generating by 20 years to 2030. This change in life is consistent with the October 23, 2006 MPUC Order 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 $1.5 million for the North Dakota electric jurisdiction.

Q. ARE THERE OTHER COST ELEMENTS RELATED TO THE AMOUNT OF UTILITY PLANT IN-SERVICE INVESTMENT?

A. Yes. Real estate and personal property taxes are directly related to utility plant in-service investment. Increases in real estate and personal property taxes result from additional investment in plant and facilities and from higher assessment levels by taxing authorities. As a result, the revenue requirement for real estate and property taxes has increased by $764,000 since 2005.

Q. PLEASE DISCUSS THE COMPONENTS OF YOUR CALCULATION OF "GROSS MARGIN GROWTH" SHOWN ON EXHIBIT___(AEH-1), SCHEDULE 9, PAGE 1, LINE 9.

A. This line item shows the change in retail operating income from the 2005 actual year to the 2008 test year. The level of kilowatt-hour sales has increased since 2005, thereby causing an increase in retail operating income, which has provided a partial offset to some of the effects of increasing costs of operations. This change is derived from the addition of new customers, as well as any changes in use per customer.

Specifically, the retail operating income was calculated by using total revenues excluding the following costs, which are recovered separately: (1) city franchise fees; (2) cost of fuel and purchased energy; and (3) transmission of energy by others. Retail margin growth is partially offset by the sharing of trading margins with North Dakota retail customers. In the 2005 actual year, the Company included trading margins as an offset to North Dakota electric jurisdictional revenue requirements. In the 2008 Test Year, the Company proposes to share a portion of these trading margins with customers through the fuel adjustment clause, which excludes them from the determination of base rates. This issue is discussed further in the testimony of Mr. Alan Krug and later in my testimony under Adjustments to the Income Statement.

Q. ARE THERE ANY CONTINGENCIES THAT COULD AFFECT THE COST OF TRANSMISSION?

A. Yes. There is some uncertainty about the amount of transmission revenue the Company will collect from MISO in 2008, due to changes in revenue distribution that are scheduled to begin February 1, 2008.

Q. WHAT IS THE CHANGE IN REVENUE DISTRIBUTION?

A. Under the provisions of the MISO Transmission Owners Agreement, revenue distribution changes at the end of the Transition Period, beginning February 1, 2008. Previously, MISO transmission revenues were distributed either 100 percent to the host pricing zone, or shared among all transmission owners 50 percent based on gross transmission plant and 50 percent based on power flows. Beginning February 1, 2008, all revenues are to be distributed based on revenue requirement. While this new method is completely different than the procedures currently in place, it is not expected to dramatically affect the NSP Companies' share of MISO transmission revenue, assuming that all load under the MISO Transmission and Energy Markets Tariff ("TEMT") is billed for transmission service. However, because of an unexpected situation, there is potential for over $61 million of revenue reallocation among MISO transmission owners.

Q. WHAT IS THE UNEXPECTED SITUATION TO WHICH YOU REFER?

A. When Ameren joined MISO as a Transmission Owner, a Stipulation agreement was filed between Ameren, the Missouri Commission and MISO, prohibits MISO from billing Ameren bundled load in Missouri until October 2009. However, if Ameren collects its share of total revenues based on its revenue requirement, but does not pay for network service for its bundled load in Missouri, the other owners would be shorted approximately $61 million per year in revenue.

Q. WHAT IS THE EFFECT OF THIS REVENUE SHORTFALL ON THE NSP COMPANIES?

A. Approximately 10 percent of the shortfall, or $6.1 million annually, would be allocated to the Company and NSP-Wisconsin.

Q. UNDER WHAT CONDITIONS WILL THIS SHORTFALL OCCUR?

A. If MISO moves to the new revenue distribution procedures, the shortfall will occur. However, since this shortfall is an unforeseen consequence that was not intended to occur after the MISO Transition Period ended, almost all transmission Owners but Ameren are sponsoring a tariff change to solve the problem by having MISO impute the unbilled revenues before calculating revenue distribution shares. While most transmission owners expect FERC to approve this change effective February 1, 2008, there is some chance that the revenue shortfall will happen if FERC fails to approve the tariff change.

Q. PLEASE DISCUSS THE COST ELEMENTS OF THE REVENUE DEFICIENCY RELATED TO OPERATING EXPENSES.

A. Exhibit___(AEH-1), Schedule 9, Page 2 of 2, shows a summary of the change in operating expenses by functional class over the three-year span between the 2005 and the 2008 test period in this case. The schedule also shows a calculation of the average annual percent of increase over the same period.

Q. ARE THE FUNCTIONAL CLASS CATEGORIES OF OPERATING EXPENSE COMPARABLE BETWEEN THE 2008 TEST YEAR BUDGET AND THOSE CONTAINED IN 2005?

A. Yes. Budget and actual accounts for both periods conform to the FERC Uniform System of Accounts.

Q. DO 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. WHY HAVE YOU EXCLUDED FERC ACCOUNT 565, TRANSMISSION OF ENERGY BY OTHERS, FROM O&M EXPENSE AND INCLUDED IT IN THE DETERMINATION OF GROSS MARGIN GROWTH?

A. Revenues for the provision of transmission service included in other electric operation revenues are related to a majority of the expense included in transmission of energy by others. Therefore, this transmission expense was included in the determination of the gross margin rather than O&M expense.

Q. WHAT IS THE AMOUNT OF CHANGE IN O&M COSTS SINCE 2005?

A. Excluding the cost of fuel and purchased energy, operating expenses have increased in total by $11,810,000 since the 2005. Most of this change reflects higher O&M costs associated with: 1) electric generating facilities; 2) purchased capacity costs; and 3) distribution expense.

Q. WHAT HAVE BEEN THE MAIN REASONS FOR INCREASE IN COSTS ASSOCIATED WITH ELECTRIC GENERATING FACILITIES?

A. The main reason for the increase in costs associated with electric generating facilities is an increase in nuclear operating expenses. The increase in cost from 2005 to the 2008 budget is approximately $68.8 million for the Company and $3,748,000 for the North Dakota electric retail jurisdiction. The reasons for this increase are discussed in detail in the testimony of Mr. Charles Bomberger.

Q. PLEASE SUMMARIZE THE COMPANY'S RECENT REQUEST FOR A CHANGE IN THE PREFERRED ACCOUNTING METHOD FOR COSTS ASSOCIATED WITH ROUTINE NUCLEAR REFUELING OUTAGES.

A. Currently, the Company uses the direct-expense method for the costs associated with reloading the nuclear reactors with fuel, which are incurred during refueling outages at our three nuclear plants. Since the number of refueling outages scheduled in any given year will vary, with two outages occurring in most years, one in other years, and the potential for even three refueling outages occurring in some years, the expenses associated with these outages will also swing significantly from year to year. We have filed a separate request with the Commission to approve a deferral-and-amortization method under which refueling costs would be deferred and amortized during the period between refueling outages, as opposed to being expensed in the year that the costs are incurred. The deferral method would produce nearly identical expense levels to those requested in the test year (deferral would reduce the expense by approximately $173,000).

Q. PLEASE EXPLAIN HOW THE DEFERRAL-AND-AMORTIZATION METHOD PROVIDES A BETTER REFLECTION OF REFUELING COSTS IN A RATE CASE.

A. The goal of ratemaking is to establish rates that reflect cost levels representative of actual costs incurred. Since the costs associated with refueling outages will vary from year to year, it is difficult to reflect a reasonable cost in a test year based on the current direct expense methodology. By applying the deferral-and-amortization method, these costs are smoothed and made more predictable by spreading costs over the period in which the benefit of the refueling outage is provided to customers. Once the first full cycle of refueling outages occurs for all three nuclear units, and costs of all three nuclear units are reflected in the amortization, the costs are more stable, and reflective of ongoing expense levels.

Q. PLEASE EXPLAIN HOW THE COMPANY IS PROPOSING TO REFLECT THE DEFERRAL-AND-AMORTIZATION METHODOLOGY IN THE TEST YEAR?

A. Currently, the Company is requesting recovery of $2,492,000 in refueling outage related expenses for the 2008 test year based on the direct expense methodology. This amount reflects two scheduled outages in 2008, both at the Prairie Island plant, Units 1 & 2. If approved by the Commission, under the deferral-and-amortization methodology, the Company would record amortized refueling outage expenses of $812,000 in 2008, 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 North Dakota jurisdictional expense amount that represents a more normal level of expense, reflecting a full cycle of refueling outages, is $2,319,000.

If the Commission approves our separate application to use the deferral method, the Company proposes using a normalized fuel outage expense of $2,319,000 in the rate case test year, thereby reducing the requested increase by $173,000. The Company believes this rate case provides an opportune time to implement this accounting change in North Dakota, allowing new rates to be established at more normal levels.

Q. HAVE THERE BEEN OTHER REASONS FOR INCREASED COSTS AT THE COMPANY'S ELECTRIC GENERATING FACILITIES?

A. Yes. Costs have increased at several of our electric generating facilities by approximately $23.1 million for the Company and $1,786,000 for the North Dakota jurisdiction. These cost increases are primarily driven by: (1) a number of turbine generator overhauls scheduled to occur in 2008; (2) increases in the cost and amount of chemical sorbent for pollution control equipment at both our King and SHERCO plants; and (3) an increase in employees also at our King and SHERCO plants.

Q. WHAT HAVE BEEN THE MAIN REASONS FOR THE INCREASE IN COSTS ASSOCIATED WITH PURCHASED CAPACITY COSTS?

A. Between 2005 and the 2008 Budget, purchased capacity costs have increased approximately $46.4 million for the Company and $2,496,000 for the North Dakota jurisdiction. The primary reason for the increase in purchased capacity costs is that the Company entered into two new purchased power agreements since 2005. In 2006, the Company entered into an agreement with Calpine to purchase energy from their combined cycle facility in Mankato, Minnesota. The second PPA agreement was with Invenergy effective in 2008 for the purchase of energy from their combustion turbine facility in Cannon Falls, Minnesota.

Q. PLEASE BRIEFLY DISCUSS THE MAIN REASON FOR INCREASE IN DISTRIBUTION EXPENSE.

A. Distribution expense for the North Dakota electric retail jurisdiction has increased by $1,528,000. This increase is largely due to the direct assignment of distribution costs to the Minot area, rather than budgeting costs centrally and allocating a portion to the Minot area. We believe that this cost assignment more accurately reflects the level of service provided to this area. In addition to this increase, the Company's tree trimming costs have increased approximately $200,000.

V. JURISDICTIONAL COST OF SERVICE STUDY

Q. PLEASE DESCRIBE THE COMPONENTS OF THE JURISDICTIONAL COST OF SERVICE STUDY FOR THE TEST YEAR.

A. The complete jurisdictional cost of service is included in my testimony at Exhibit___(AEH-1), Schedule 8. 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 summary of the jurisdictional cost of service consists of Schedule 7, Revenue Deficiency Summary, and Schedule 8. In Schedule 8, the cover page identifies the North Dakota Retail jurisdiction requested return on equity, and shows the earned return on equity under current rates, the revenue deficiency, and the percent of increase that would result if rates were increased to earn the requested return on equity (in this case 11.5 percent). The "Rate Base Summary" for total Company electric operations and the North Dakota jurisdiction is shown on Schedule 8, Page 2. On Schedule 8, Page 3 an "Income Statement Summary" for total Company electric operations and the North Dakota jurisdiction is shown. 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 North Dakota jurisdiction is shown on Schedule 8, 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 8, Page 3. Schedule 8, Page 5 shows the

"Revenue Requirement and Return Summary" for total Company electric operations and the North Dakota jurisdiction. Specifically, the schedule shows the calculated earned overall rate of return on rate base, calculated earned rate of return on common stock equity capital, the revenue deficiency that needs to be recovered to enable the North Dakota jurisdiction electric operations to earn the requested return on common equity and finally, 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 8, Page 6, is carried back to the rate base on Schedule 8, Page 2.

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

A. Yes. The revenue conversion factor calculation is included in my exhibits at Exhibit___(AEH-1), Schedule 10.

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 SCHEDULE IN YOUR EXHIBIT THAT IS RELATED TO THE INCOME STATEMENT.

A. Exhibit___ (AEH-1) Schedule 11, Page 1 of 2, is a comparative income statement for the 2008 test 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 North Dakota jurisdiction electric utility operations. Schedule 11, Page 2 of 2, shows an electric utility comparative income statement for the North Dakota jurisdiction and total Company for the 2008 test year before making test period adjustments. The operating income statement after making the proposed test period adjustments is also shown on Page 2 of 2.

VI. UTILITY AND JURISDICTIONAL ALLOCATIONS

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

A. The test 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 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 MPUC (MPUC Docket No. E002/GR-05-1428). 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 it software or other common investments and expenses, are evaluated as to whether the cost should be direct assigned to Electric or Gas, or allocated based on appropriate allocators such as:

Customers, Customer Bills, Transportation Studies, or the Three Factor allocator (the average of Revenue Ratio, Employee Ratio, and Asset Ratio).

Q. PLEASE DESCRIBE THE METHODS USED TO ALLOCATE COSTS FOR THE COMPANY'S ELECTRIC UTILITY OPERATIONS IN NORTH DAKOTA.

A. O&M cost assignments and allocations are summarized on Exhibit___(AEH-1) Schedule 12. The expense budgets relied upon to develop test year income statement items were generally prepared on a functional basis (*i.e.,* Production, Transmission, Distribution, Customer Accounts, Customer Information, Sales, Administrative and General). These functional amounts are directly assigned to North Dakota jurisdiction electric operations or allocated to the electric operations based on cost causation.

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

A. A summary and description of the allocation factors used to allocate expenses and capital items to the North Dakota jurisdictional electric operations income statement and rate base is contained in Exhibit___(AEH-1) Schedule 13. 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 NSP-Wisconsin operating companies through the Interchange Agreement as approved by FERC and discussed later in my testimony. The Company's portion of costs is then shared among customers in North Dakota, Minnesota and South Dakota, as well as a group of wholesale customers with rates regulated by FERC. To determine the level of investment associated with the provision of electric service to North Dakota retail customers, it is necessary to assign or allocate a portion of the total production and transmission investment to each jurisdiction. We used each jurisdiction's respective coincident peak demands for electricity as the basis for this allocation. 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. This is consistent with the methodology accepted in the last North Dakota electric rate cases, Case No. PU-400-92-399, and reflects the fact that these facilities have been designed to meet peak requirements.

Q. HOW WERE THE DISTRIBUTION INVESTMENT AMOUNTS ASSIGNED TO THE NORTH 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.

VII. RATE BASE COMPONENTS

Q. IS THE 2008 TEST YEAR RATE BASE FOR THE XCEL ENERGY – NORTH DAKOTA JURISDICTION ELECTRIC OPERATIONS REASONABLE FOR PURPOSES OF DETERMINING FINAL RATES IN THIS PROCEEDING?

A. Yes. The test year rate base was developed on sound ratemaking principles in a manner similar to prior Company electric rate cases.

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 PROJECTED TEST YEAR RATE BASE.

A. The test 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
- Short-term Construction Work in Progress
- Accumulated Deferred Income Taxes
- Other Rate Base Items

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

A. Exhibit___(AEH-1), Schedule 14, Page 1 of 2, shows a detailed statement of the Average Rate Base by component for the 2008 Test Year. Schedule 14, Page 2 of 2, is a comparative statement of the 2008 Test Year Average Rate Base for the North Dakota jurisdiction and total company, before and after making proposed test period adjustments. Exhibit___(AEH-1), Schedule 2, page 2 shows the Company's actual 2006 Average Rate Base as provided in the May 1, 2007 jurisdictional annual report to the Commission, revised as described above.

VIII. 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 simple average of projected net plant balances at the beginning and end of the test year. Such treatment is consistent with the method employed in the most recent North Dakota electric rate case, Case No. PU-400-92-399.

Q. WHAT HISTORICAL BASE DID XCEL ENERGY RELY ON AS A STARTING POINT TO DEVELOP THE PROJECTED NET PLANT BALANCES FOR THE BEGINNING OF THE TEST 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 as of May 31, 2007.

Q. ON WHAT BASIS WERE NET PLANT BALANCES PROJECTED FOR THE END OF THE TEST YEAR?

A. The ending net plant balances were determined by applying the data contained in the 2008 capital budget to the above-described beginning test year balances, adjusted for retirements, depreciation, salvage and removal costs projected to occur during the test year.

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

A. The average net utility plant included in the test year rate base is $242,100,000, as shown on Exhibit___(AEH-1), Schedule 8, Page 2. This is comprised of an average plant balance of $607,339,000 as detailed on Exhibit___(AEH-1), Schedule 14, Page 1, minus an average depreciation reserve of $333,166,000, also shown by component on Exhibit___(AEH-1), Schedule 14, Page 1.

IX. CONSTRUCTION WORK IN PROGRESS

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

A. Yes. The only CWIP that is included in rate base are costs related to projects of a short-duration that do not accrue Allowance for Funds Used During Construction ("AFUDC"). Thus, there is no AFUDC offset added to operating income. The rate base amount reflects a simple average of projected CWIP beginning and ending test year balances. This is consistent with the method employed in the most recent North Dakota electric rate case (Case No. PU-400-92-399) and matches the use of an average rate base.

Q. HOW WERE THE TEST YEAR BEGINNING AND ENDING CWIP BALANCES DETERMINED?

A. The beginning test year balance for CWIP was the May 31, 2007 historical balance. The beginning test year CWIP balance was adjusted to reflect projected construction expenditures, and transfers to Plant in Service during the 2008 test year to obtain the ending test year CWIP balance. These projections were developed from the Company's 2008 capital budget.

Q. WHAT WAS THE LEVEL OF SHORT-TERM CWIP INCLUDED IN THE TEST YEAR RATE BASE?

A. As shown on Exhibit___(AEH-1), Schedule 8, Page 2, the average short-term CWIP included in rate base was $4,802,000.

X. 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 TEST YEAR RATE BASE?

A. As shown on Exhibit___(AEH-1), Schedule 8, Page 2, $40,717,000 was deducted. This amount reflects a simple average of the beginning and projected ending test year ADIT balances.

XI. 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 HAVE TEST YEAR MATERIALS AND SUPPLIES AND FUEL INVENTORY REQUIREMENTS BEEN CALCULATED?

A. The Materials and Supplies and Fuel Inventory amounts shown on Exhibit___(AEH-1), Schedule 8, Page 2, are based on the thirteen-month average balances projected during the test year. Materials and Supplies average balance included in the test year rate base equals $5,412,000. The test year average rate base amount for Fuel Inventory is $2,358,000.

Q. HOW HAVE THE TEST YEAR NON-PLANT ASSETS & LIABILITIES BEEN DETERMINED?

A. These balances as shown on Exhibit___(AEH-1), Schedule 8, Page 2, represent the 2008 calendar year estimate of these 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 test year rate base by $6,928,000.

Q. HOW HAVE THE TEST YEAR PREPAYMENTS AND OTHER WORKING CAPITAL ITEMS BEEN DETERMINED?

A. Items of Prepayments and Other Working Capital such as customer advances and deposits, are based on the actual thirteen-month average balances during the period ended May 31, 2007, as a proxy for the test year. The unamortized balances included in this section are based on the amortization schedules as described later in my testimony on revenue requirements. The net impact of these various items increase test year rate base by $1,864,000 as shown on Exhibit___(AEH-1), Schedule 8, Page 2.

Q. HOW HAVE THE TEST YEAR CASH WORKING CAPITAL REQUIREMENTS BEEN DETERMINED?

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

Q. HAVE THE COMPONENTS OF THE TEST YEAR CASH WORKING CAPITAL BEEN CALCULATED CONSISTENT WITH METHODS USED IN THE MOST RECENTLY APPROVED NORTH DAKOTA ELECTRIC RATE CASE (CASE NO. PU-400-92-399)?

A. Yes.

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. A positive net revenue lag means that, on average, Xcel Energy investors have provided cash working capital, and are entitled to a return thereon.

Q. HAS XCEL ENERGY'S LEAD/LAG STUDY BEEN UPDATED SINCE THE LAST NORTH DAKOTA ELECTRIC RATE CASE (CASE NO. PU-400-92-399)?

A. Yes. A new lead/lag study was prepared in 2004 for gas operations in conjunction with applications for gas general rate increases that were filed in North Dakota (Case No. PU-400-04-578) and 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 2005 Minnesota electric general rate increase application (Docket No E002/GR-05-1428). Many components of the lead/lag study associated with electric operations have been updated once more 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 2005 Minnesota electric rate case. The results of the updated lead/lag study for electric operations were incorporated into the North Dakota jurisdiction cash working capital calculations as shown on Exhibit (AEH-1), Schedule 8, Page 2.

Q. WHAT IS THE TEST YEAR CASH WORKING CAPITAL AMOUNT?

A. The amount included in the average rate base is a positive $1,136,000. The components of this amount are summarized in Exhibit___(AEH-1), Schedule 8, Page 6.

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

A. 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. In the Company's circumstance, taxing authorities comprise the largest source of cash working capital as offsets to working capital provided by the Company's investors. Other sources of offsets may include customers, creditors and employees. When a positive cash working capital exists, or is required, it is added to rate base to compensate the Company's investors for funds provided to meet cash working capital requirements.

XII. ADJUSTMENTS TO RATE BASE

Q. PLEASE IDENTIFY THE TEST YEAR ADJUSTMENTS TO THE 2008 BUDGET FOR RATE BASE.

A. We made rate base adjustments to the 2008 budget for the: (i) Pole Inspection and Replacement Program; and (ii) Cable Replacement Program.

Q. WHY HAVE YOU MADE ADJUSTMENTS TO THE TEST YEAR FOR POLE INSPECTION AND REPLACEMENT, AND CABLE REPLACEMENT PROGRAMS?

A. These two adjustments are the result of business decisions that were made after the 2008 budget was established. The business decisions will result in increased costs that will occur in 2008 for these two programs, which are very important to the safe and reliable operation of our system.

Q. WHAT IS THE POLE INSPECTION AND REPLACEMENT PROGRAM?

A. After the 2008 budget was established, the Company examined our pole testing practices to determine if they were consistent with our ongoing goals of ensuring reliable service for our customers and maintaining a safe work environment for our employees. Based on the information gathered, we changed our pole inspection program to establish a 15-year pole inspection and pole replacement plan. This inspection and replacement plan will allow us to replace poles before they fail, reducing outages and enhancing worker and public safety.

Q. PLEASE EXPLAIN FURTHER THE POLE INSPECTION AND REPLACEMENT COSTS YOU HAVE INCLUDED AS AN ADJUSTMENT TO THE TEST YEAR.

A. The pole inspection program examines all poles in our system (approximately 21,200 located in North Dakota) over a 15-year period. If a pole is found to be defective, it will be replaced. Our pilot tests indicate an average 4 percent replacement rate. The adjustment to the test year for this program includes and additional $92,000 of O&M expenses and $184,000 of capital expenditures to replace the poles.

Q. PLEASE EXPLAIN FURTHER THE CABLE REPLACEMENT COSTS YOU HAVE INCLUDED AS AN ADJUSTMENT TO THE TEST YEAR.

A. The Company's current cable replacement program has been in place for many years. The program involves examining various spans of cable to determine whether there is any indication that the cable is vulnerable to sudden failure. A scoring method is used to quantify the level of risk associated with each span of cable tested. Upon review of the scores of recent testing, the Company decided that additional cables needed to be replaced in order to maintain the reliability and safety of our system in North Dakota. These cable replacement costs include $25,000 in O&M expenses, and $500,000 in capital expenditures.

XIII. INCOME STATEMENT

A. Revenues

Q. WAS THE IMPACT OF WEATHER ON PROJECTED SALES FOR THE TEST YEAR CONSIDERED?

A. Yes. Test year retail sales levels assume normal weather. The test year sales volumes are supported by the direct testimony of Ms. Jannell Marks.

Q. DO RETAIL OPERATING REVENUES REFLECT THE PROJECTED LEVEL OF UNBILLED SALES VOLUMES IN THE TEST YEAR?

A. Yes. This adjustment is incorporated into retail sales forecast, the effect of which is to project the level of revenues on a calendar-month basis.

Q. HAS THE COMPANY MADE SIMILAR ADJUSTMENTS IN PRIOR RATE CASES TO RECOGNIZE THE NET CHANGE IN UNBILLED REVENUES DURING THE TEST YEAR?

A. Yes. The adjustment is consistent with the methodology in the last Xcel Energy North Dakota electric and natural gas rate cases (Case Nos. PU-400-92-399, PU-06-525).

Q. WHAT IS THE PURPOSE OF MAKING AN UNBILLED REVENUE CALCULATION IN THE TEST YEAR?

A. The unbilled revenue calculation is used to determine the total revenue requirement for electric operations in the North Dakota jurisdiction. Including unbilled revenues in the determination of revenue requirements reflects a proper matching of revenues with expense on a calendar year basis.

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

A. Yes. The test-year includes items such as revenues from sales to other utilities, transmission-related revenue and specific tariff charges including service activation fees, reconnection fees and others. In areas where the

Company did not budget for the collection of these tariffed charges, a representative level was determined and included as part of the revenues in the cost of service study. One other source of revenues comes from billings to NSP-W under the Interchange Agreement, which I discuss in more detail below.

B. Operating and Maintenance Expenses

Q. HOW DOES XCEL ENERGY DEVELOP ITS TEST YEAR PRODUCTION EXPENSE BUDGET?

A. The main area of expense in the production expense budget is fuel and purchased power. These expenses are developed through a production budget prepared to serve the combined energy and demand requirements of both the Company and NSP-Wisconsin. Our Risk Management Department conducts a PROSYM model run based on the forecasted system sales to derive the forecasted fuel and energy costs. The total system fuel and energy costs are then adjusted to remove the cost of inter-system sales and other non-recoverable fuel items so that a base cost of fuel is derived that only recovers the appropriate North Dakota jurisdictional share of these system fuel costs. The Energy Markets group also forecasts our capacity purchases for contracts that will be in place during the test year and for short-term seasonal capacity purchases for the summer season, as well as transmission expenses forecast to be paid to others.

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 15 percent of the costs of the Company system are allocated to NSP-Wisconsin, and approximately 85 percent of the NSP-Wisconsin system costs are allocated to the Company, because approximately 85 percent of the load on the integrated system is the Company load and 15 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. Interchange Agreement costs and revenues are budgeted by the Company and NSP-Wisconsin annually. Thus, the Company's budget shows Interchange Revenues -- revenues that reflect the charges to NSP-Wisconsin for its share of production and transmission assets and associated expenses. Likewise, Interchange Expense reflects the

Company's forecasted payments to NSP-Wisconsin for its proportionate share of the costs of generation and transmission assets and associated expenses incurred by NSP-Wisconsin to serve the system needs.

C. Depreciation Expense

Q. PLEASE IDENTIFY THE DOCKETS ASSOCIATED WITH THE DEPRECIATION RATES USED IN THIS PROCEEDING.

A. Depreciation Expense for the test year reflects the depreciation rates last certified by the MPUC and is consistent with the ongoing practice followed by the Company in North 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 and the treatment of lobbying expenses.

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

A. This legislation 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 11.5 percent return on equity. I estimate that the value of the tax deduction is a reduction to the revenue requirements of approximately $97,000. 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 not shown in the bridge schedule as an adjustment.

Q. YOU ALSO MENTIONED LOBBYING. ARE ANY DOLLARS RELATED TO CIVIC OR POLITICAL ACTIVITIES (LOBBYING), IDENTIFIED IN THE COST OF SERVICE, OR ADJUSTMENTS?

A. No. Beginning in 1999, Northern States Power Company made a conscious effort to move all lobbying costs to below the line accounting, FERC account 426.4, Expenditures for certain civic, political and related activities. Thus, no adjustment to the cost of service for lobbying is required, as these below the line amounts are not used in our development of the cost of service.

XIV. ADJUSTMENTS TO THE INCOME STATEMENT

Q. PLEASE IDENTIFY THE ADJUSTMENTS TO THE INCOME STATEMENT.

A. We made income statement adjustments for the following items:

A. Interest on Customer Deposits;

B. Advertising Expenses

C. Incentive Compensation Adjustment

D. Economic Development Adjustment

E. Charitable Contributions

F. Saver's Switch Adjustment

G. Pole Inspection and Replacement Program

H. Cable Testing Program

I. Rate Case Expense Amortization

J. Renewable Development Fund Amortization

K. Private Fuel Storage Amortization

L. Asset Based Trading Margin Sharing

M. Non-Asset Based Trading Margin Sharing

N. MISO Schedule 16 and 17 Expense

O. Association Dues

P. Cash Working Capital

A brief description of each income statement adjustment is provided below.

A. Interest on Customer Deposits

Q. HOW ARE CUSTOMER DEPOSITS TREATED IN THIS APPLICATION?

A. Customer deposits are treated as customer supplied capital and thus it is appropriate to pay ratepayers a return on that investment. This interest expense adjustment is reflected on Exhibit ___ (AEH-1), Schedule 3 and Exhibit ___ (AEH-1), Schedule 5, page 2.

B. Advertising Expenses

Q. WHAT IS THE LEVEL OF ADVERTISING EXPENSE INCLUDED IN THE TEST YEAR?

A. The Projected Year advertising expenses for the North Dakota jurisdiction are $510,000, of which $151,000 has been included in the test year. The primary driver of the includable advertising costs is safety at $101,000. The remaining $50,000 is made up of the following categories: $26,000 for General Advertising, and $23,000 for Customer Programs.

Of the $359,000 being excluded, the Company has excluded the entire Brand and Image advertising budget totaling $232,000. This includes costs associated with television, print, radio and outdoor advertisement and is used by the Brand Advertising Department. This adjustment is reflected on Exhibit ___ (AEH-1), Schedule 3 and Exhibit ___ (AEH-1), Schedule 5, page 2.

C. Incentive Compensation Adjustment

Q. PLEASE SUMMARIZE ADJUSTMENTS MADE TO THE TEST YEAR COST OF SERVICE TO EXCLUDE COSTS FOR PARTS OF THE COMPANY'S ANNUAL INCENTIVE COMPENSATION PROGRAMS.

A. Consistent with the Commission's Order in the Company's previous gas rate case, the test year reflects the exclusion of the long-term portion of the officer's incentive compensation, any non-corporate incentive plan costs, and all incentive plan costs above twenty-five percent of base pay. The Company's annual incentive compensation programs were budgeted at the target level for 2008. The Company has also removed all expenses associated with the Company's Supplemental Executive Retirement Plan ("SERP") consistent with prior Commission practice. The determination of the incentive compensation expense is shown on Exhibit___(AEH-1), Schedule 4. This adjustment is reflected on Exhibit ___ (AEH-1), Schedule 4 and Exhibit ___ (AEH-1), Schedule 5, page 2.

D. Economic Development Adjustment

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR ECONOMIC DEVELOPMENT COSTS.

A. Because all economic development costs were recorded as below-the-line donations, an adjustment is necessary to include economic development contributions. This treatment is consistent with prior regulatory treatment in North Dakota. This adjustment is reflected on Exhibit ___ (AEH-1), Schedule 3 and Exhibit ___ (AEH-1), Schedule 5, page 2.

E. Charitable Contributions

Q. HAVE YOU INCLUDED AMOUNTS IN THE TEST YEAR COST OF SERVICE RELATED TO CHARITABLE CONTRIBUTIONS?

A. Yes. The Company is proposing to include fifty percent of charitable contributions attributable to the State of North Dakota in the test year. Contributions made by the Company during 2006 were used as a proxy for the 2008 test year. An analysis was performed on contribution detail to insure that only amounts contributed to charities and institutions that could be associated with the electric service territory in the North Dakota jurisdiction were included in the cost of service.

Charitable contributions have not previously been included in the development of electric base rates in North Dakota. However, we note that the Commission has allowed recovery of fifty percent of these costs in the determination of North Dakota gas rates in our last two gas rate case proceedings. Here, we respectfully request similar treatment for the determination of North Dakota electric base rates. This adjustment is reflected on Exhibit ___ (AEH-1), Schedule 4 and Exhibit ___ (AEH-1), Schedule 5, page 2.

F. Saver's Switch Adjustment

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR SAVER'S SWITCH COSTS.

A. The 2008 Budget included approximately $37,000 of expense related to the Saver's Switch program. As discussed by Mr. Kent Larson, the Company is planning to request the Commission's permission to implement a Demand Side Management ("DSM") program in North Dakota, including a tracking mechanism. As a part of our DSM proposal, we request authorization to include costs related the Saver's Switch program in the alternative DSM cost recover mechanism. Therefore, since these costs would be included in an alternative cost recovery plan, we exclude them from our base rate request. This adjustment is reflected on Exhibit ___ (AEH-1), Schedule 4 and Exhibit ___ (AEH-1), Schedule 5, page 2.

G. Pole Inspection and Replacement Program

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR THE POLE INSPECTION AND REPLACEMENT PROGRAM.

A. A detailed explanation of the pole inspection and replacement program is included under the above-discussed Adjustments to Rate Base. The O&M adjustment related to this program is reflected on Exhibit ___ (AEH-1), Schedule 4 and Exhibit ___ (AEH-1), Schedule 5, pages 1 and 2.

H. Cable Replacement Program

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR THE CABLE REPLACEMENT PROGRAM.

A. A detailed explanation of the cable replacement program is included under the above-discussed Adjustments to Rate Base. The O&M adjustment related to this program is reflected on Exhibit ___ (AEH-1), Schedule 4 and Exhibit ___ (AEH-1), Schedule 5, pages 1 and 2.

I. Rate Case Expense Amortization

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

A. The amortization includes $100,000 of projected direct expenses associated with this Notice of Rate Change docket. Consistent with the settlement of its last North Dakota natural gas rate case (Case No. PU06-525), the Company has used a three-year amortization period for these expenses. An amount based on a three-year amortization of projected costs of $300,000 is proposed for inclusion in the cost of service with no rate base treatment of the unamortized balance. Three years is reasonable because the Company expects to file its next electric rate case in approximately three years. This adjustment is reflected on Exhibit ___ (AEH-1), Schedule 4 and Exhibit ___ (AEH-1), Schedule 5, page 2.

J. Renewable Development Fund

Q. PLEASE EXPLAIN THE AMORTIZATION OF RENEWABLE DEVELOPMENT FUND EXPENSE IN THIS PROCEEDING.

A. The Renewable Development fund ("RDF") amortization represents the North Dakota allocated portion of RDF grants awarded to Energy Production projects and budgeted to be paid in 2008. Before the MPUC approves a grant award to an energy production project, a signed purchase power agreement must be approved. Energy produced from these projects also benefit North Dakota electric customers. Xcel Energy is not requesting recovery from North Dakota electric customers of RDF grant payments related to research and development projects, production incentives and other projects determined to benefit only Minnesota state customers. This adjustment is reflected on Exhibit ___ (AEH-1), Schedule 4 and Exhibit ___ (AEH-1), Schedule 5, page 2.

K. Private Fuel Storage Amortization

Q. WHAT IS THE BASIS FOR THE COMPANY'S PROPOSAL TO RECOVER ITS EXPENSE IN PRIVATE FUEL STORAGE, LLC ("PFS")?

A. As explained by Mr. Bomberger in his Direct Testimony, Xcel Energy has expended approximately $23 million in PFS in an effort to obtain a license from the Nuclear Regulatory Commission to develop a private independent spent fuel storage installation within the Goshute Indian tribal land in Utah. In Xcel Energy's last Minnesota electric rate case, the MPUC approved a six-year amortization of these costs beginning in 2006. The 2008 portion of the six-year amortization of investment for private fuel storage is $3,279,000 or $190,000 for the North Dakota jurisdiction. This adjustment is reflected on Exhibit ___ (AEH-1), Schedule 4 and Exhibit ___ (AEH-1), Schedule 5, page 2.

L. Asset Based Trading Margin Sharing

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR THE SHARING OF ASSET BASED TRADING MARGINS.

A. As discussed in the testimony of Mr. Al Krug, the Company is proposing to share 85 percent of asset based trading and ancillary service margins with North Dakota electric customers, retaining 15 percent for our shareholders. Current rates include these margins in base rates. We propose here to share them with customers through the electric fuel clause recovery mechanism. This adjustment is reflected on Exhibit ___ (AEH-1), Schedule 4 and Exhibit ___ (AEH-1), Schedule 5, page 2.

M. Non-Asset Based Trading Margin Sharing

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR THE SHARING OF NON-ASSET BASED TRADING MARGINS.

A. Also discussed in Mr. Krug's testimony is the sharing of 15 percent of the Company's non-asset based trading margins with North Dakota electric customers, including margins shared with Public Service Company of Colorado and Southwestern Public Service Company through the Joint Operating Agreement. We propose to retain the other 85 percent of these margins for our shareholders. Additionally, our proposal includes only the sharing of positive net margins. As was discussed with asset based trading margins, we propose here to share these margins with customers through the electric fuel clause recovery mechanism. The Company's last North Dakota electric rate case (filed in 1992 with a 1993 test year) did not include any non-asset based trading margins, as we did not actively participate in this type of transaction at that time. This adjustment is reflected on Exhibit ___ (AEH-1), Schedule 4 and Exhibit ___ (AEH-1), Schedule 5, page 2.

N. MISO Schedule 16 and 17 Expenses

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR MISO SCHEDULE 16 AND 17 EXPENSES.

A. The Company is currently operating under an April 6, 2005 Interim Order from the Commission (Case No. PU-05-147), authorizing recovery of MISO Schedules 16 and 17 administrative expenses through the electric fuel clause adjustment mechanism. For the reasons explained in Mr. Stephen Beuning's Direct Testimony, the Company proposes to exclude recovery of these costs from fuel clause recovery and instead build these costs into base rates.

When these costs were recovered from customers through the FCA, they were assigned to customers based on the energy allocator. However, for purposes of allocating these transmission related costs to the North Dakota electric jurisdiction for inclusion in base rates, we use the demand allocator. Because a different allocation method is used, there is a slight difference in the amount that would have been recovered from customers in revenue ($532,000) and the amount of expense for base rate determination ($522,000). Since the adjustment is to fuel clause revenues, we have excluded $532,000, in fuel clause revenues but included an expense adjustment of $522,000. This adjustment is reflected on Exhibit ___ (AEH-1), Schedule 4 and Exhibit ___ (AEH-1), Schedule 5, page 2.

O. Association Dues

Q. PLEASE DESCRIBE THE ORGANIZATIONAL DUES INCLUDED IN TEST YEAR EXPENSE.

A. The Projected Year expense for organizational dues for the North Dakota electric jurisdiction is $125,000, of which $15,000 is for professional dues and $110,000 is for dues related directly to the electric utility. All social, civic and political or chamber of commerce organization dues are booked below-the-line and are not included in Projected Year expense. Therefore, no adjustment was necessary.

P. Cash Working Capital

Q. PLEASE DESCRIBE THE CASH WORKING CAPITAL ADJUSTMENT

A. The adjustment entitled "Cash Working Capital," as shown in Ex. __ (AEH-1) Schedule 5, Schedule of Income Statement Adjustments, represents the calculated change in the provision for current income taxes that was caused by the adjustment to the amount of Cash Working Capital included in the Total Rate Base.

Q. WHY IS IT NECESSARY TO ADJUST THE AMOUNT OF CASH WORKING CAPITAL INCLUDED IN TOTAL RATE BASE?

A. Various test period adjustments that were made in the Income Statement to various functions of O&M expense have an effect on the amount of cash working capital that is required to conduct electric operations. For example, a change in current income tax would affect the amount of cash working capital included in rate base. The results of the cash working capital computations are included in the Total Rate Base.

Q. WHY WAS THERE A REDUCTION IN THE CURRENT INCOME TAX EXPENSE AS A RESULT OF THE CHANGE IN THE AMOUNT OF CASH WORKING CAPITAL INCLUDED IN TOTAL RATE BASE?

A. Exhibit ___ (AEH-1), Schedule 5 includes a reduction in income tax expense of $2,000 as a result of the change in Cash Working Capital. This results because the amount of the interest expense deduction used in the calculation of current income taxes is determined by the interest synchronization method. Simply stated, interest for income tax purposes is calculated by multiplying the average rate base by the weighted cost of debt. Thus, because there is a change in the amount of average rate base, due to the amount of required Cash Working Capital changing, the amount of the interest deduction calculated for income tax purposes also changed.

Q. HOW ARE THE COSTS OF LOBBYING ACTIVITIES TREATED IN THIS APPLICATION?

A. Lobbying costs are recorded as non-operating expenses below-the-line and are not included in the cost of service.

XV. CONCLUSION

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

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application of Northern States Power Company, a Minnesota Corporation For Authority to Increase Rates for Electric Service in North Dakota	))))	Case No. PU-07-___

AFFIDAVIT OF
Anne E. Heuer

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Anne E. Heuer

Anne E. Heuer

Subscribed and sworn to before me, this 4 day of December, 2007.

____
Notary Public

NANCY A. HALEY
NOTARY PUBLIC • MINNESOTA
MY COMMISSION EXPIRES
JANUARY 31, 2010

Northern States Power Company, a Minnesota Corporation
Electric Utility – State of North 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 – Xcel Energy Services Inc.
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

ROE = 8.62%
Deficiency = $5,376
% Increase = 3.87%
Required ROE = 12.00%

Northern States Power Company, a Minnesota Corporation
Electric Utility - North Dakota Retail Jurisdiction
Cost of Service Study
2006 Actuals

With Retail Revenues

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Jurisdictional Cost of Service Study
2006 Actual
(Dollars in Thousands)

Case No. PU-07-____
Exhibit ___ (AEH-1)
Schedule 2, Page 2 of 6

Rate Base Summary

		Total Company Electric			North 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	9,378,598	9,631,969	9,505,284	528,856	537,889	533,373	8,849,742	9,094,080	8,971,911
2	Depreciation Reserve	(5,414,290)	(5,590,793)	(5,502,542)	(309,991)	(320,218)	(315,105)	(5,104,299)	(5,270,575)	(5,187,437)
3	Net Utility Plant	3,964,308	4,041,176	4,002,742	218,865	217,671	218,268	3,745,443	3,823,505	3,784,474
4	C.W.I.P.	42,791	91,769	67,280	2,103	4,666	3,385	40,688	87,103	63,895
5	Accumulated Deferred Taxes	(699,154)	(707,120)	(703,137)	(37,050)	(37,278)	(37,164)	(662,104)	(669,842)	(665,973)
	Other Rate Base:									
6	Cash Working Capital	0	0	0	0	0	0	0	0	0
7	Materials & Supplies	92,531	92,531	92,531	5,602	5,602	5,602	86,929	86,929	86,929
8	Fuel Inventory	35,202	35,202	35,202	2,052	2,052	2,052	33,150	33,150	33,150
9	Non-Plant Assets & Liab	(112,054)	(116,363)	(114,209)	(6,820)	(7,088)	(6,954)	(105,234)	(109,275)	(107,255)
10	Prepaids & Other	18,299	18,299	18,299	1,114	1,114	1,114	17,185	17,185	17,185
11	**Total Rate Base**	**3,341,923**	**3,455,494**	**3,398,708**	**185,866**	**186,739**	**186,303**	**3,156,057**	**3,268,755**	**3,212,405**

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Jurisdictional Cost of Service Study
2006 Actual
(Dollars in Thousands)

Case No. PU-07-____
Exhibit ___ (AEH-1)
Schedule 2, Page 3 of 6

Income Statement Summary

		Total Company Electric	ND Retail Electric	All Other
	Operating Revenues			
1	Retail	2,591,289	138,765	2,452,524
2	CIP Adjustment to Program Costs	0	0	0
3	Interdepartmental	496	0	496
4	Other Operating	757,747	41,872	715,875
5	Gross Earnings Tax	0	0	0
6	**Total Operating Revenues**	**3,349,532**	**180,637**	**3,168,895**
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	1,268,001	73,905	1,194,096
8	Power Production	615,843	33,652	582,191
9	Transmission	111,279	6,568	104,711
10	Distribution	99,304	4,792	94,512
11	Customer Accounting	63,782	4,677	59,104
12	Customer Service & Information	58,768	271	58,496
13	Sales, Econ Dvlp & Other	162	4	158
14	Administrative & General	165,473	10,505	154,968
15	Total Operating Expenses	2,382,611	134,375	2,248,237
16	Depreciation	349,394	18,913	330,481
17	Amortization	33,953	509	33,444
	Taxes:			
18	Property	100,783	5,580	95,203
19	Gross Earnings	0	0	0
20	Deferred Income Tax & ITC	3,433	(51)	3,484
21	State & Federal Income (see Page 3)	140,345	5,818	134,527
22	Payroll & Other	18,551	1,101	17,450
23	Total Taxes	263,112	12,447	250,664
24	**Total Expenses**	**3,029,070**	**166,244**	**2,862,826**
25	AFUDC	0	0	0
26	**Total Operating Income**	**320,462**	**14,393**	**306,069**

(Dollars in Thousands)

Income Tax Summary

		Total Company Electric	ND Retail Electric	All Other
	Income Before Taxes			
1	Total Operating Revenues	3,349,532	180,637	3,168,895
2	less: Total Operating Expenses	(2,382,611)	(134,375)	(2,248,237)
3	Book Depreciation & Amortization	(383,347)	(19,422)	(363,925)
4	Taxes (Other Than Current Income)	(122,767)	(6,630)	(116,137)
5	**Total Before Tax Book Income**	**460,806**	**20,210**	**440,596**
	Tax Additions			
6	Book Depreciation	349,394	18,913	330,481
7	Nuclear Fuel Book Burn	50,742	3,053	47,689
8	Nuclear Fuel Disposal	12,659	762	11,897
9	Book Depreciation Cleared To Operating	0	0	0
10	Deferred Income Taxes & ITC	3,433	(51)	3,484
11	Book Amortizations	0	0	0
12	Connection Fees	0	0	0
13	Avoided Tax Interest	40,967	2,364	38,603
14	Tax Capitalized Leases	0	0	0
15	Meals & Entertainment	528	32	496
16	TBT Net Expense	0	0	0
17	**Total Tax Additions**	**457,723**	**25,073**	**432,650**
	Tax Deductions			
18	Tax Depreciation & Removal Expense	486,491	25,905	460,586
19	Debt Interest Expense	111,478	6,111	105,367
20	Manufacture Production Deduction	4,562	284	4,278
21	Other Tax/Book Timing Differences	(27,513)	(1,726)	(25,787)
22	Net Preferred Stock Deduction	0	0	0
23	**Total Tax Deductions**	**575,018**	**30,574**	**540,166**
24	**State Taxable Income**	**343,512**	**14,710**	**328,802**
25	State Income Tax Rate	9.01%	7.00%	N/A
26	**Total State Income Taxes**	**30,947**	**1,030**	**29,918**
27	**Federal Taxable Income**	**312,565**	**13,680**	**298,885**
28	Federal Income Tax Rate	35.00%	35.00%	35.00%
29	**Total Federal Income Taxes**	**109,398**	**4,788**	**104,610**
30	**Total Federal & State Income Taxes**	140,345	5,818	134,527

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Jurisdictional Cost of Service Study
2006 Actual

Case No. PU-07-____
Exhibit ___ (AEH-1)
Schedule 2, Page 5 of 6

Revenue Requirement & Return Summary

(Dollars in Thousands)

	Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt	6.8300%	47.5765%	3.2400%
2	Short Term Debt	4.6100%	0.8352%	0.0400%
3	Preferred Stock	0.0000%	0.0000%	0.0000%
4	Common Equity	12.0000%	51.5883%	6.1900%
5	**Required Rate of Return**			**9.4700%**

Composite Income Tax Rates		
State of North Dakota Tax rate		7.00%
Federal Statutory Tax rate	35.00%	
Federal Effective Tax Rate (1-State Rate * Fed Rate)		32.55%
Total North Dakota Composite Tax Rate		**39.55%**
Total Corporate Composite Tax Rate		**40.86%**

		Total Company Electric	ND Retail Electric	All Other
	Rate of Return (ROR)			
6	Total Operating Income	320,462	14,393	306,069
7	Total Average Rate Base	3,398,708	186,303	3,212,405
8	**ROR (Operating Income / Rate Base)**	**9.43%**	**7.73%**	**9.53%**
	Return on Equity (ROE)			
9	Total Operating Income	320,462	14,393	306,069
10	Debt Interest (Rate Base * Weighted Debt Cost)	(111,478)	(6,111)	(105,367)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	208,984	8,282	200,702
13	Equity Rate Base (Rate Base * Equity Ratio)	1,753,336	96,111	1,657,225
14	**ROE (Earnings for Common / Equity Rate Base)**	**11.92%**	**8.62%**	**12.11%**
	Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Return)	321,858	17,643	304,215
16	Operating Income	320,462	14,393	306,069
17	Operating Income Deficiency	1,396	3,250	(1,854)
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.69079	1.65426	N/A
19	**Revenue Deficiency (Income Deficiency * Conversion Fac**	**2,360**	**5,376**	**(3,016)**
	Total Retail Revenue Requirements			
20	Retail Related Revenues	2,591,785	138,765	2,453,020
21	Revenue Deficiency	2,360	5,376	(3,016)
22	**Total Retail Revenue Requirements**	**2,594,145**	**144,141**	**2,450,004**
23	**Percentage Increase (Decrease)**	**0.09%**	**3.87%**	**-0.12%**

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Jurisdictional Cost of Service Study
2006 Actual
(Dollars in Thousands)

Case No. PU-07-____
Exhibit ___ (AEH-1)
Schedule 2, Page 6 of 6

Rate Base Detail - Cash Working Capital

			Total Company Electric			ND 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	0.00	199,253	0		11,613	0		187,640	0
2	Gas for Generation	0.00	57,941	0		3,377	0		54,564	0
3	Oil	0.00	4,956	0		289	0		4,667	0
4	Nuclear & EOL	0.00	63,401	0		3,695	0		59,705	0
5	Nuclear Disposal	0.00	12,422	0		0	0		12,422	0
6			337,973	0		18,975	0		318,998	0
	Purchased Power									
7	Purchases	0.00	1,104,162	0		51,559	0		1,052,603	0
8	Interchange	0.00	99,403	0		5,892	0		93,511	0
			1,203,564	0		57,450	0		1,146,114	0
	Labor & Related Costs									
9	Regular Payroll	0.00	224,673	0		12,904	0		211,769	0
10	Incentive Compensation	0.00	23,794	0		1,441	0		22,354	0
11	Pension & Benefits	0.00	42,343	0		2,587	0		39,757	0
12	Subtotal Labor & Related		290,811	0		16,932	0		273,879	0
14	All Other Operating Expenses	0.00	550,264	0		41,018	0		509,246	0
15	Property Tax	0.00	100,783	0		5,580	0		95,203	0
16	Employer's Payroll Taxes	0.00	18,551	0		1,101	0		17,450	0
17	Gross Earnings Tax	0.00	0	0		0	0		0	0
18	Federal Income Tax	0.00	109,398	0		4,788	0		104,610	0
19	State Income Tax	0.00	30,947	0		1,030	0		29,918	0
20	State Sales Tax Customer Billings	0.00	101,239	0		0	0		101,239	0
21	Total Expenses	0.00	2,743,529	0	0.00	146,873	0	0.00	2,596,656	0
22	**Net Annual Expense Amount**			0			0			0
	Revenues	Lag Days	Dollars	Dollar x Days		Dollars	Dollar x Days		Dollars	Dollar x Days
23	Computer Billing 100.00%	0.00	2,591,289	0		138,765	0		2,452,524	0
24	Hand Billed 0.00%	0.00	0	0		0	0		0	0
25	Retail Revenue Adjustments	0.00	0	0		0	0		0	0
26	Interdepartmental	0.00	496	0		0	0		496	0
27	Late Payment	0.00	8,135	0		309	0		7,826	0
28	Connect and Trouble Charges	0.00	2,733	0		244	0		2,489	0
29	CIP Incentive	0.00	0	0		0	0		0	0
30	Rentals	0.00	5,056	0		193	0		4,863	0
31	Interchange Revenues	0.00	311,530	0		18,419	0		293,111	0
32	Sales for Resale	0.00	356,556	0		18,250	0		338,306	0
33	Production Associated Revenues	0.00	3,657	0		213	0		3,444	0
34	MISO	0.00	32,704	0		1,930	0		30,774	0
35	Point to Point Firm	0.00	23,438	0		1,383	0		22,055	0
36	Services & Facilities	0.00	9,225	0		541	0		8,684	0
37	Ancillary	0.00	5,580	0		329	0		5,251	0
38	Distribution Associated Revenues	0.00	321	0		85	0		236	0
39	Other	0.00	1,365	0		125	0		1,240	0
40	JOA - Rev fr/to PSC	0.00	(2,553)	0		(149)	0		(2,404)	0
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	0.00	3,349,532	0	0.00	180,637	0	0.00	3,168,895	0
45	Net Annual Amount			0			0			0
46	Expense / Revenue Factor			0.819078294			0.813083006			
47	**Allocated Revenue Amount**			0			0			
48	**Net Cash Working Capital**	Page 1 - Line 6		0			0			0
42	**Net Cash Working Capital**	Page 1 - Line 6		0			0			0

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
SUMMARY OF TRADITIONAL REGULATORY & DATA REVIEW ADJUSTMENTS
($000's)

Case No. PU-07-____
Exhibit ___ (AEH-1)
Schedule 3, Page 1 of 1

	Adjustment Description	Adjustment Target	Total Co.	ND Juris.	Allocation Method
1	Interchange Decommisioning	Other Revenue	(9,759)	(564)	Demand
2	MISO Network Revenue Adj	Other Revenues	1,876	108	Demand
3	MISO Sch 2 Revenue Adj	Other Revenues	6,774	392	Demand
4	Total Revenue		(1,109)	(64)	
5	Advertising Expenses	Administrative & General	(4,271)	(359)	Direct/Customer
6	Economic Development Costs	Administrative & General	342	173	Direct/Customer
7	Interest on Customer Deposits	Administrative & General	34	2	Customer
8	Total Administrative & General	Administrative & General	(3,895)	(184)	
9	King Chemicals Adjustment	Production	-	517	Demand
10	Tree Trimming Correction from SD to ND	Distribution	-	1,224	Direct
11	MISO Day 2 Sched 16 & 17 move from FERC 565 to FERC 575.7	Transmission	(12,639)	(731)	Demand
		Production	12,639	731	Demand

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
SUMMARY OF TEST PERIOD ADJUSTMENTS
($000's)
red = updated

Case No. PU-07-____
Exhibit ___ (AEH-1)
Schedule 4, Page 1 of 1

	Adjustment Description	Adjustment Target	Total Co.	ND Juris.	Allocation Method
1	Asset Based Trading-Ratepayer sharing	Retail Revenues	(1,800)	(1,800)	Direct
2	Asset Based Trading-Shareholder sharing	Other Revenues	(318)	(318)	Direct
3	Non-Asset Based Trading-Ratepayer sharing	Retail Revenues	(39)	(39)	Direct
4	Non-Asset Based Trading-Shareholder sharing	Other Revenues	(221)	(221)	Direct
5	MISO Sch 16 & 17 Revenue Margin Adj	Retail Revenues	(532)	(532)	Direct
6	Total Revenues	Revenues	(2,910)	(2,910)	
7	Charitable Contributions	Administrative & General	1,737	86	Direct/Customer
	Incentive Compensation				
8	Amounts in Excess of 25%	Administrative & General	(766)	(45)	Customer/Labor
9	Other Bonuses/Incentives	Administrative & General	(740)	(43)	Customer/Labor
10	Long Term Incentive Plans	Administrative & General	(4,385)	(234)	Customer/Labor
11	Net Incentive Comp Adjustment	Administrative & General	(5,891)	(322)	
12	Total Administrative & General		(4,154)	(236)	
13	Saver Switch	Customer Info	(37)	(37)	Direct
14	Pole Inspection and Replacement Program	Distribution	92	92	Direct
15	Cable Replacements	Distribution	25	25	Direct
16	Private Fuel Storage	Amortization	3,279	190	Demand
17	ND Rate Case Expense Amortization	Amortization	100	100	Direct
18	RDF Amortization	Amortization	22,702	170	Direct
19	Total Expenses		22,007	304	
	Pole Inspection and Replacement Program	Rate Base			
20		BOY CWIP	-	-	Direct
21		EOY CWIP	-	-	Direct
22		BOY Plant In Service		-	Direct
23		EOY Plant In Service	184	184	Direct
24		BOY Depreciation Reserve	-	-	Direct
25		EOY Depreciation Reserve	3	3	Direct
26		BOY Accumulated Deferred T	-	-	Direct
27		EOY Accumulated Deferred T	2	2	Direct
		Income Statement			
28		Book Depreciation Expense	3	3	Direct
29		Deferred Tax Expense	2	2	Direct
30		AFUDC	-	-	Direct
31		Tax Depreciation (Schedule M	7	7	Direct
32		Tax Addition	-	-	Direct
	Cable Replacement Program	Rate Base			
33		BOY CWIP	-	-	Direct
34		EOY CWIP	-	-	Direct
35		BOY Plant In Service		-	Direct
36		EOY Plant In Service	500	500	Direct
37		BOY Depreciation Reserve	-	-	Direct
38		EOY Depreciation Reserve	6	6	Direct
39		BOY Accumulated Deferred T	-	-	Direct
40		EOY Accumulated Deferred T	5	5	Direct
		Income Statement			
41		Book Depreciation Expense	6	6	Direct
42		Deferred Tax Expense	5	5	Direct
43		AFUDC	-	-	Direct
44		Tax Depreciation (Schedule M	19	19	Direct
45		Tax Addition	-	-	Direct

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Rate Base Schedules
Rate Base Adjustment Schedules
2008 Unadjusted Test Year versus 2008 Adjusted Test Year
($000's)

Case No. PU-07-____
Exhibit ___ (AEH-1)
Schedule 5, Page 1 of 4

Line No.	Description	Unadjusted (F)	Pole Inspection & Replacement Program (G)	Cable Replacement Program (H)	Income Statement (I)	Adjusted
	Electric Plant as Booked					
1	Production	$356,704				$356,704
2	Transmission	$87,557				$87,557
3	Distribution	$123,860	$92	$250		$124,202
4	General	$14,538				$14,538
5	Common	$24,338				$24,338
6	TBT Investment	$0				$0
7	TOTAL Utility Plant in Service	$606,997	$92	$250		$607,339
	Reserve for Depreciation					
8	Production	$234,339				$234,339
9	Transmission	$29,941				$29,941
10	Distribution	$48,234	$2	$3		$48,239
11	General	$6,955				$6,955
12	Common	$13,692				$13,692
13	TOTAL Reserve for Depreciation	$333,161	$2	$3		$333,166
	Net Utility Plant in Service					
14	Production	$122,365				$122,365
15	Transmission	$57,616				$57,616
16	Distribution	$75,626	$91	$247		$75,964
17	General	$7,583				$7,583
18	Common	$10,646				$10,646
19	TBT Investment	$0				$0
20	Net Utility Plant in Service	$273,836	$91	$247		$274,173
21	Utility Plant Held for Future Use	$0				$0
22	Construction Work in Progress	$4,802				$4,802
23	Less: Accumulated Deferred Income Taxes	$40,713	$1	$3		$40,717
24	Cash Working Capital	$951			$185	$1,136
	Other Rate Base Items:					
25	Materials and Supplies	$5,412				$5,412
26	Fuel Inventory	$2,358				$2,358
27	Non-Plant Assets & Liabilities	($6,928)				($6,928)
28	Prepayments	$1,127				$1,127
29	Customer Advances	($60)				($60)
30	Other Working Capital	$797				$797
31	Total Other Rate Base Items	$2,706	$0	$0	$0	$2,706
32	Total Average Rate Base	$241,582	$90	$245	$185	$242,100

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
OPERATING INCOME STATEMENT SCHEDULES
OPERATING INCOME STATEMENT ADJUSTMENT SCHEDULES
2008 Unadjusted Test Year versus 2008 Adjusted Test Year
($000's)

Line No.	Description	2008 Base Data	Interest on Customer Deposits 1	Advertising 2	Incentive Pay 3	Economic Development 4	Charitable Contributions 5
	Operating Revenues						
1	Retail	$149,550					
2	CIP Revenue Adjustment	0					
3	Interdepartmental	0					
4	Other Operating	40,064					
5	Gross Earnings Tax	0					
6	**Total Operating Revenues**	$189,614	$0	$0	$0	$0	$0
	Expenses						
	Operating Expenses:						
7	Fuel & Purchased Energy	$79,015					
8	Power Production	40,491					
9	Transmission	7,992					
10	Distribution	5,538					
11	Customer Accounting	4,343					
12	Customer Service & Information	406					
13	Sales, Econ Dvlp & Other	2					
14	Administrative & General	10,819	2	(359)	(322)	173	86
15	Amortization	0					
16	Total Operating Expenses	$148,605	$2	($359)	($322)	$173	$86
17	Depreciation	$19,151					
	Taxes:						
18	Property	$5,763					
19	Gross Earnings	0					
20	Deferred Income Tax & ITC	1,731					
21	Federal & State Income Tax	1,420	(1)	141	126	(68)	(34)
22	Payroll & Other	1,310					
23	Total Taxes	$10,224	($1)	$141	$126	($68)	($34)
24	**Total Expenses**	$177,980	$1	($218)	($196)	$105	$52
25	Allowance for Funds Used During Construction	$0					
26	**Total Operating Income**	$11,634	($1)	$218	$196	($105)	($52)

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
OPERATING INCOME STATEMENT SCHEDULES
OPERATING INCOME STATEMENT ADJUSTMENT SCHEDULES
2008 Unadjusted Test Year versus 2008 Adjusted Test Year
($000's)

Line No.	Description	Saver Switch 6	Pole Inspection & Replacement Program 7	Cable Replacement Program 8	Rate Case Expense Amortization 9	RDF Amortization 10	Privat Fuel Storage 11
	Operating Revenues						
1	Retail						
2	CIP Revenue Adjustment						
3	Interdepartmental						
4	Other Operating						
5	Gross Earnings Tax						
6	**Total Operating Revenues**	$0	$0	$0	$0	$0	$0
	Expenses						
	Operating Expenses:						
7	Fuel & Purchased Energy						
8	Power Production						
9	Transmission						
10	Distribution		92	25			
11	Customer Accounting						
12	Customer Service & Information	(37)					
13	Sales, Econ Dvlp & Other						
14	Administrative & General						
15	Amortization				100	170	190
16	Total Operating Expenses	($37)	$92	$25	$100	$170	$190
17	Depreciation		$3	$6			
	Taxes:						
18	Property						
19	Gross Earnings						
20	Deferred Income Tax & ITC		2	5			
21	Federal & State Income Tax	15	(40)	(20)	(39)	(67)	(75)
22	Payroll & Other						
23	Total Taxes	$15	($38)	($15)	($39)	($67)	($75)
24	**Total Expenses**	($22)	$57	$16	$61	$103	$115
25	Allowance for Funds Used During Construction						
26	**Total Operating Income**	$22	($57)	($16)	($61)	($103)	($115)

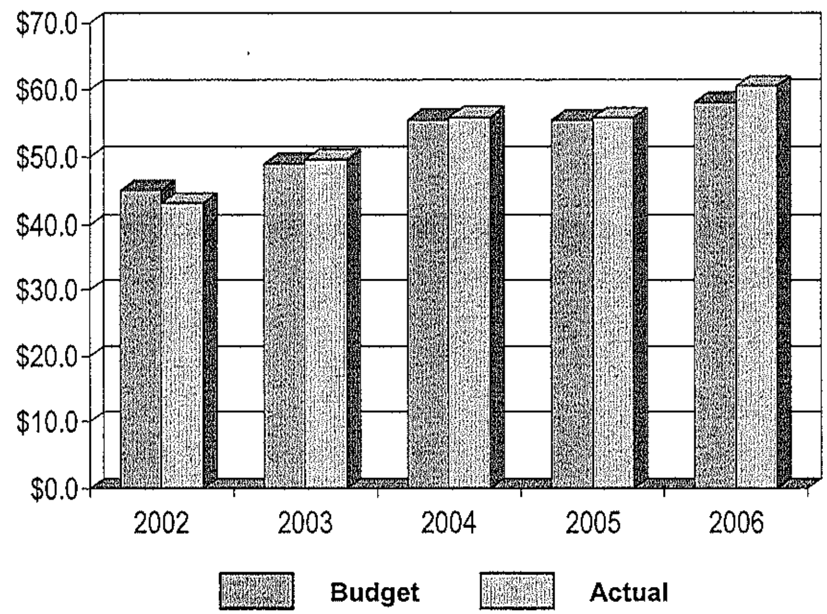
Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
OPERATING INCOME STATEMENT SCHEDULES
OPERATING INCOME STATEMENT ADJUSTMENT SCHEDULES
2008 Unadjusted Test Year versus 2008 Adjusted Test Year
($000's)

Line No.	Description	Asset Based Trading-Ratepayer sharing 12	Asset Based Trading-Shareholder sharing 13	Non-Asset Based Trading-Ratepayer sharing 14	Non-Asset Based Trading-Shareholder sharing 15	MISO Sch 16 & 17 Margin Adj 16	CWC 17	2008 Adjusted(1)
	Operating Revenues							
1	Retail	(1,800)		(39)		($532)		$147,179
2	CIP Revenue Adjustment							$0
3	Interdepartmental							$0
4	Other Operating		(318)		(221)			$39,525
5	Gross Earnings Tax							$0
6	**Total Operating Revenues**	($1,800)	($318)	($39)	($221)	($532)	$0	$186,704
	Expenses							
	Operating Expenses:							
7	Fuel & Purchased Energy							$79,015
8	Power Production							$40,491
9	Transmission							$7,992
10	Distribution							$5,655
11	Customer Accounting							$4,343
12	Customer Service & Information							$369
13	Sales, Econ Dvlp & Other							$2
14	Administrative & General							$10,399
15	Amortization							$460
16	Total Operating Expenses	$0	$0	$0	$0	$0	$0	$148,724
17	Depreciation							$19,160
	Taxes:							
18	Property							$5,763
19	Gross Earnings							$0
20	Deferred Income Tax & ITC							$1,738
21	Federal & State Income Tax	(706)	(125)	(15)	(87)	(209)	(2)	$214
22	Payroll & Other							$1,310
23	Total Taxes	($706)	($125)	($15)	($87)	($209)	($2)	$9,025
24	**Total Expenses**	($706)	($125)	($15)	($87)	($209)	($2)	$176,910
25	Allowance for Funds Used During Construction	$0		$0			$0	$0
26	**Total Operating Income**	($1,094)	($193)	($24)	($134)	($323)	$2	$9,794

Northern States Power Company, a Minnesota Corporation
Electric Utility – State of North Dakota
Comparison of O&M Actuals to Budget

Case No. PU-07-____
Exhibit___(AEH-1), Schedule 6
Page 1 of 1

Xcel Energy Electric (N.D. Jurisdiction)



Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Revenue Deficiency Summary
($000's)

Case No. PU-07-____
Exhibit___(AEH-1)
Schedule 7, Page 1 of 1

Line	Description	North Dakota Jurisdiction
1	Average Rate Base	$242,100
2	Operating Income (Before AFUDC)	$9,794
3	Allowance for Funds Used During Construction	$0
4	Total Available for Return (Line 2 + Line 3 + Rounding)	$9,794
5	Overall Rate of Return (Line 4 / Line 1)	4.05%
6	Required Rate of Return	9.20%
7	Operating Income Requirement (Line 1 x Line 6)	$22,273
8	Income Deficiency (Line 7 - Line 6)	$12,479
9	Gross Revenue Conversion Factor	1.64555
10	Revenue Deficiency (Line 8 x Line 9)	$20,535
11	Retail Related Revenue Under Present Rates	$147,179
13	Percentage Increase Needed in Overall Revenue (Line 10 / Line 11)	13.95%

ROE = 1.54%

Deficiency = $20,535

% Increase = 13.95%

Required ROE = 11.50%

Northern States Power Company, a Minnesota Corporation
Electric Utility - North Dakota Retail Jurisdiction
Cost of Service Study
2008 Test Year

Summary Reports

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Cost of Service Study
2008 Budget
(Dollars in Thousands)

Case No. PU-07-____
Exhibit ____(AEH-1)
Schedule 8, Page 2 of 6

Rate Base Summary

		Total Company Electric			North 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	10,486,491	11,699,172	11,092,832	572,054	642,623	607,339	9,914,437	11,056,549	10,485,493
2	Depreciation Reserve	(5,821,431)	(6,216,224)	(6,018,828)	(322,262)	(344,069)	(333,166)	(5,499,169)	(5,872,155)	(5,685,662)
3	Net Utility Plant	4,665,060	5,482,948	5,074,004	249,792	298,554	274,173	4,415,268	5,184,394	4,799,831
4	C.W.I.P.	471,316	244,824	358,070	5,117	4,487	4,802	466,199	240,338	353,268
5	Accumulated Deferred Taxes	(759,615)	(788,332)	(773,974)	(39,716)	(41,717)	(40,717)	(719,899)	(746,615)	(733,257)
	Other Rate Base:									
6	Cash Working Capital	12,339	12,339	12,339	1,136	1,136	1,136	11,202	11,202	11,202
7	Materials & Supplies	92,681	92,681	92,681	5,412	5,412	5,412	87,269	87,269	87,269
8	Fuel Inventory	40,111	40,111	40,111	2,358	2,358	2,358	37,753	37,753	37,753
9	Non-Plant Assets & Liab	(115,650)	(118,027)	(116,839)	(6,856)	(6,999)	(6,928)	(108,794)	(111,028)	(109,911)
10	Prepaids & Other	30,355	30,355	30,355	1,864	1,864	1,864	28,491	28,491	28,491
11	**Total Rate Base**	**4,436,596**	**4,996,899**	**4,716,747**	**219,107**	**265,095**	**242,100**	**4,217,489**	**4,731,804**	**4,474,646**

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Cost of Service Study
2008 Budget
(Dollars in Thousands)

Case No. PU-07-____
Exhibit ____(AEH-1)
Schedule 8, Page 3 of 6

Income Statement Summary

		Total Company Electric	ND Retail Electric	All Other
	Operating Revenues			
1	Retail	2,877,113	147,179	2,729,934
2	CIP Adjustment to Program Costs	0	0	0
3	Interdepartmental	434	0	434
4	Other Operating	725,631	39,525	686,106
5	Gross Earnings Tax	0	0	0
6	**Total Operating Revenues**	**3,603,178**	**186,704**	**3,416,474**
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	1,344,010	79,015	1,264,995
8	Power Production	686,183	40,491	645,692
9	Transmission	138,216	7,992	130,224
10	Distribution	110,071	5,655	104,416
11	Customer Accounting	59,420	4,343	55,077
12	Customer Service & Information	60,501	369	60,133
13	Sales, Econ Dvlp & Other	138	2	136
14	Administrative & General	161,492	10,399	151,093
15	Total Operating Expenses	2,560,030	148,264	2,411,766
16	Depreciation	365,768	19,160	346,608
17	Amortization	27,513	460	27,053
	Taxes:			
18	Property	105,494	5,763	99,731
19	Gross Earnings	0	0	0
20	Deferred Income Tax & ITC	64,161	1,738	62,423
21	State & Federal Income (see Page 3)	86,218	214	86,004
22	Payroll & Other	21,401	1,310	20,091
23	Total Taxes	277,274	9,025	268,249
24	**Total Expenses**	**3,230,585**	**176,910**	**3,053,675**
25	AFUDC	0	0	0
26	**Total Operating Income**	**372,593**	**9,794**	**362,799**

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Cost of Service Study
2008 Budget
(Dollars in Thousands)

Case No. PU-07-____
Exhibit ____(AEH-1)
Schedule 8, Page 4 of 6

Income Tax Summary

		Total Company Electric	ND Retail Electric	All Other
	Income Before Taxes			
1	Total Operating Revenues	3,603,178	186,704	3,416,474
2	less: Total Operating Expenses	(2,560,030)	(148,264)	(2,411,766)
3	Book Depreciation & Amortization	(393,281)	(19,620)	(373,661)
4	Taxes (Other Than Current Income)	(191,056)	(8,811)	(182,245)
5	**Total Before Tax Book Income**	**458,811**	**10,008**	**448,803**
	Tax Additions			
6	Book Depreciation	365,768	19,160	346,608
7	Nuclear Fuel Book Burn	69,384	4,012	65,372
8	Nuclear Fuel Disposal	12,473	721	11,752
9	Book Depreciation Cleared To Operating	0	0	0
10	Deferred Income Taxes & ITC	64,161	1,738	62,423
11	Book Amortizations	0	0	0
12	Connection Fees	0	0	0
13	Avoided Tax Interest	59,766	3,412	56,354
14	Tax Capitalized Leases	0	0	0
15	Meals & Entertainment	528	32	496
16	TBT Net Expense	0	0	0
17	**Total Tax Additions**	**572,080**	**29,075**	**543,005**
	Tax Deductions			
18	Tax Depreciation & Removal Expense	665,489	30,605	634,884
19	Debt Interest Expense	153,294	7,868	145,426
20	Man Prod Ded / Prod Tax Credit	5,093	310	4,783
21	Other Tax/Book Timing Differences	(4,082)	(246)	(3,836)
22	Net Preferred Stock Deduction	0	0	0
23	**Total Tax Deductions**	**819,794**	**38,537**	**776,474**
24	**State Taxable Income**	**211,097**	**546**	**210,550**
25	State Income Tax Rate	8.99%	6.51%	N/A
26	**Total State Income Taxes**	**18,976**	**36**	**18,940**
27	**Federal Taxable Income**	**192,121**	**511**	**191,610**
28	Federal Income Tax Rate	35.00%	35.00%	35.00%
29	**Total Federal Income Taxes**	**67,242**	**179**	**67,064**
30	**Total Federal & State Income Taxes**	86,218	214	86,004

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Cost of Service Study
2008 Budget
(Dollars in Thousands)

Case No. PU-07-____
Exhibit ____(AEH-1)
Schedule 8, Page 5 of 6

Revenue Requirement & Return Summary

	Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt	6.7900%	45.6100%	3.1000%
2	Short Term Debt	5.7400%	2.6200%	0.1500%
3	Preferred Stock	0.0000%	0.0000%	0.0000%
4	Common Equity	11.5000%	51.7700%	5.9500%
5	**Required Rate of Return**			**9.2000%**

Composite Income Tax Rates		
State of North Dakota Tax rate		6.50%
Federal Statutory Tax rate	35.00%	
Federal Effective Tax Rate (1-State Rate * Fed Rate)		32.73%
Total North Dakota Composite Tax Rate		**39.23%**
Total Corporate Composite Tax Rate		**40.84%**

		Total Company Electric	ND Retail Electric	All Other
	Rate of Return (ROR)			
6	Total Operating Income	372,593	9,794	362,799
7	Total Average Rate Base	4,716,747	242,100	4,474,646
8	**ROR (Operating Income / Rate Base)**	**7.90%**	**4.05%**	**8.11%**
	Return on Equity (ROE)			
9	Total Operating Income	372,593	9,794	362,799
10	Debt Interest (Rate Base * Weighted Debt Cost)	(153,294)	(7,868)	(145,426)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	219,299	1,926	217,373
13	Equity Rate Base (Rate Base * Equity Ratio)	2,441,860	125,335	2,316,524
14	**ROE (Earnings for Common / Equity Rate Base)**	**8.98%**	**1.54%**	**9.38%**
	Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Return)	433,941	22,273	411,667
16	Operating Income	372,593	9,794	362,799
17	Operating Income Deficiency	61,348	12,479	48,869
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.69041	1.64555	N/A
19	**Revenue Deficiency (Income Deficiency * Conversion Factor)**	**103,704**	**20,535**	**83,169**
	Total Retail Revenue Requirements			
20	Retail Related Revenues	2,877,547	147,179	2,730,368
21	Revenue Deficiency	103,704	20,535	83,169
22	**Total Retail Revenue Requirements**	**2,981,251**	**167,714**	**2,813,537**
23	**Percentage Increase (Decrease)**	**3.60%**	**13.95%**	**3.05%**

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Cost of Service Study
2008 Budget
(Dollars in Thousands)

Case No. PU-07-____
Exhibit ____(AEH-1)
Schedule 8, Page 6 of 6

Rate Base Detail - Cash Working Capital

				Total Company Electric			ND 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		24.78	367,060	9,095,753		21,579	534,739		345,481	8,561,014
2	Gas for Generation		41.90	139,412	5,841,374		8,196	343,414		131,216	5,497,960
3	Oil		14.13	7,092	100,215		417	5,892		6,675	94,324
4	Nuclear & EOL		0.00	80,062	0		4,707	0		75,355	0
5	Nuclear Disposal		76.38	12,473	952,688		721	55,070		11,752	897,618
6				606,100	15,990,030		35,620	939,115		570,480	15,050,915
	Purchased Power										
7	Purchases		24.62	989,971	24,373,094		57,960	1,426,977		932,011	22,946,117
8	Interchange		38.21	103,226	3,944,260		5,991	228,902		97,235	3,715,358
				1,093,197	28,317,353		63,951	1,655,879		1,029,246	26,661,475
	Labor & Related Costs										
9	Regular Payroll		12.82	244,810	3,138,461		14,763	189,258		230,047	2,949,204
10	Incentive Compensation		255.13	11,547	2,945,981		683	174,224		10,864	2,771,736
11	Pension & Benefits		28.34	41,928	1,188,248		2,613	74,046		39,316	1,114,202
12	Subtotal Labor & Related			298,285	7,272,670		18,058	437,528		280,227	6,835,142
14	All Other Operating Expenses		42.34	562,448	23,814,050		30,635	1,297,090		531,813	22,516,960
15	Property Tax		353.01	105,494	37,240,437		5,763	2,034,397		99,731	35,206,040
16	Employer's Payroll Taxes		26.83	21,401	574,194		1,310	35,149		20,091	539,045
17	Gross Earnings Tax		55.01	39,086	2,150,121		2,081	114,476		37,005	2,035,645
18	Federal Income Tax		36.50	67,242	2,454,346		179	6,525		67,064	2,447,821
19	State Income Tax		36.50	18,976	692,611		36	1,298		18,940	691,313
20	State Sales Tax Customer Billings		51.86	110,642	5,737,894		0	0		110,642	5,737,894
21	Total Expenses		42.51	2,922,871	124,243,707	41.37	157,633	6,521,457	42.57	2,765,238	117,722,250
22	**Net Annual Expense Amount**				340,394			17,867			322,527
	Revenues		**Lag Days**	**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**
23	Computer Billing	100.00%	45.45	2,679,484	130,872,548		149,550	6,797,048		2,729,934	124,075,500
24	Hand Billed	0.00%	45.45	0	0		0	0		0	0
25	Retail Revenue Adjustments		45.45	(2,371)	(107,762)		(2,371)	(107,762)		0	0
26	Interdepartmental		0.00	434	0		0	0		434	0
27	Late Payment		0.00	7,252	0		245	0		7,007	0
28	Connect and Trouble Charges		45.45	2,217	100,763		173	7,863		2,044	92,900
29	CIP Incentive		0.00	0	0		0	0		0	0
30	Rentals		34.28	4,630	158,716		251	8,604		4,379	150,112
31	Interchange Revenues		38.21	388,380	14,840,000		22,648	865,380		365,732	13,974,620
32	Sales for Resale		39.63	255,111	10,110,049		12,380	490,619		242,731	9,619,430
33	Production Associated Revenues		39.63	6,382	252,919		375	14,861		6,007	238,057
34	MISO		39.63	36,762	1,456,878		2,125	84,214		34,637	1,372,664
35	Point to Point Firm		39.63	4,680	185,468		271	10,740		4,409	174,729
36	Services & Facilities		39.63	8,621	341,650		493	19,538		8,128	322,113
37	Ancillary		39.63	6,223	246,617		360	14,267		5,863	232,351
38	Distribution Associated Revenues		45.45	1,986	90,264		0	0		1,986	90,264
39	Other		45.45	5,367	243,930		320	14,544		5,047	229,386
40	JOA - Rev fr/to PSC		39.63	(1,980)	(78,467)		(116)	(4,597)		(1,864)	(73,870)
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		44.05	3,603,178	158,713,573	44.00	186,704	8,215,318	44.05	3,416,474	150,498,255
45	Net Annual Amount				434,832			22,508			412,324
46	Expense / Revenue Factor				0.811192608			0.844292943			
47	**Allocated Revenue Amount**				352,732			19,003			
48	**Net Cash Working Capital**		Page 1 - Line 6		12,339			1,136			11,202

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Summary of Primary Elements of Revenue Deficiency
2008 Test Year vs. the 2005 Regulatory Report of Electric Utility Operations Utilizing The PLUS PLAN

Case No. PU-07-____
Exhibit ___ (AEH-1)
Schedule 9, Page 1 of 2

Line	Item	Revenue Deficiency (millions)
1	Capital Recovery for additional rate base investment (includes return requirement, change in cost of capital and depreciation)	$9.885
	Operating Expenses:	
2	Power Production	$8.694
	Transmission	$0.626
	Distribution	$1.528
3	Customer Accounts	$0.149
4	Customer Services, Sales and	$0.063
	Administrative and General Expense	$0.750
5	Total Operating Expenses	$11.810
6	Taxes Other than Income Taxes - Payroll, Real Estate and Personal Property	$0.998
7	Other - Rate Case Costs - Amortization	($0.427)
8	Subtotal	$22.266
9	Less, Gross Margin Growth (Total Revenue Less Cost of Fuel, Purchased Energy and Transmission of Energy by Others)	($1.731)
10	Net Revenue Deficiency	$20.535

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota

Case No. PU-07-____
Exhibit ___ (AEH-1)
Schedule 9, Page 2 of 2

Summary of Test Year O & M Expense Changes
Since the 2005 Regulatory Report of Electric Utility Operations Utilizing The PLUS PLAN
Shown by Functional Grouping Excluding Fuel and Purchased Energy, Gross Dollar Change and Item
(dollars in thousands)

Line	Functional Class	Increase (Decrease)	Average Annual %
1	Power Production	$8,694	9.1%
2	Total Transmission	$2,070	11.7%
3	Transmission of Energy by Others - FERC 565 (1)	($1,444)	19.9%
4	Net Transmission	$626	6.0%
5	Distribution	$1,528	12.3%
6	Customer Accounting	$149	1.2%
7	Customer Services and Sales Expenses	$63	6.8%
8	Administrative and General Expenses	$750	2.6%
9	Total Operating Expenses	$11,810	7.3%

(1) Included in Gross Margin Growth

Definition: The incremental amount of gross revenue rquired to generate an additional dollar of operating income. Gross earnings fees included.

Let: GR = Gross Revenue Conversion Factor
T= Federal and North Dakota Income Tax

Formula for Gross Revenue Conversion Factor

$$GR = \frac{1}{1 - T}$$

Gross Revenue Conversion Factor:

$$GR = \frac{1}{1 - 0.3923}$$

$$GR = 1.645549$$

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Operating Income with Present and Proposed Rates
(000's)

Case No. PU-07-____
Exhibit ___ (AEH-1)
Schedule 11, Page 1 of 2

Line No.	Description	Test Year Ending 12/31/08 Present Rates (A)	Final Increase (B)	Test Year Ending 12/31/08 Final Rates (C) = (B) + (A)
	Operating Revenues			
1	Retail	$147,179	$20,535	$167,714
2	CIP Adjustment to Program Costs	0		0
3	Interdepartmental	0		0
4	Other Operating	39,525		39,525
5	Gross Earnings Tax	0		0
6	**Total Operating Revenues**	$186,704	$20,535	$207,239
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	$79,015		$79,015
8	Power Production	40,491		40,491
9	Transmission	7,992		7,992
10	Distribution	5,655		5,655
11	Customer Accounting	4,343		4,343
12	Customer Service & Information	369		369
13	Administrative & General	10,399		10,399
14	Amortizations	460		$460
15	Sales, Econ Dvlp & Other	2		2
16	Total Operating Expenses	$148,724	$0	$148,724
17	Depreciation	$19,160	$0	$19,160
	Taxes:			
18	Property	$5,763		$5,763
19	Gross Earnings	0		0
20	Deferred Income Tax & ITC	1,738		1,738
21	Federal & State Income Tax	214	8,056	8,270
22	Payroll & Other	1,310		1,310
23	Total Taxes	$9,025	$8,056	$17,081
24	**Total Expenses**	$176,910	$8,056	$184,966
25	AFUDC	$0	$0	$0
26	**Total Operating Income**	$9,794	$12,479	$22,273

Note: Revenues reflect calendar month sales.

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Statement of Operating Income
(000's)

Case No. PU-07-____
Exhibit ___ (AEH-1)
Schedule 11, Page 2 of 2

Line No.	Description	Unadjusted Total Utility (E)	Proposed Test Year 2008 Unadjusted North Dakota Jurisdiction (F)	Adjustments (G)	Proposed North Dakota Jurisdiction (H) (Col F + G)
	Operating Revenues				
1	Retail	$2,879,484	$149,550	($2,371)	$147,179
2	CIP Adjustment to Program Costs	$0	$0	0	0
3	Interdepartmental	$434	$0	0	0
4	Other Operating	$725,809	$40,064	(539)	39,525
5	Gross Earnings Tax	$0	$0	0	0
6	**Total Operating Revenues**	$3,605,727	$189,614	($2,910)	$186,704
	Expenses				
	Operating Expenses:				
7	Fuel & Purchased Energy	$1,344,010	$79,015	$0	$79,015
8	Power Production	686,183	40,491	0	40,491
9	Transmission	138,216	7,992	0	7,992
10	Distribution	109,953	5,538	117	5,655
11	Customer Accounting	59,420	4,343	0	4,343
12	Customer Service & Information	60,539	406	(37)	369
13	Administrative & General	169,540	10,819	(420)	10,399
14	Amortizations	1,432	0	$460	460
15	Sales, Econ Dvlp & Other	138	2	0	2
16	Total Operating Expenses	$2,569,430	$148,605	$120	$148,724
17	Depreciation	$365,759	$19,151	$9	$19,160
	Taxes:				
18	Property	$105,494	$5,763	$0	$5,763
19	Gross Earnings	0	0	0	0
20	Deferred Income Tax & ITC	64,154	1,731	7	1,738
21	Federal & State Income Tax	94,721	1,420	(1,206)	214
22	Payroll & Other	21,401	1,310	0	1,310
23	Total Taxes	$285,770	$10,224	($1,199)	$9,025
24	**Total Expenses**	$3,220,959	$177,980	($1,070)	$176,910
25	Allowance for Funds Used During Constructi	$0	$0	0	$0
26	**Total Operating Income**	$384,768	$11,634	($1,840)	$9,794

Line No.	Description	Allocation Basis
	The allocation factors on this page were used to determine North Dakota jurisdictional amounts for all of the years presented in these schedules.	
1	Production	Demand/Energy
2	Transmission	Demand
3	Distribution	Customers/Direct Assigned
4	Customer Accounting	Customers/Direct Assigned
5	Customer Service & Information	Customers/Direct Assigned
6	Sales, Econ Dvlp & Other	Customers/Direct Assigned
7	Administrative & General	Customers/Two Factor/Demand/Direct Assigned

		Test Year 2008		
Line No.	Allocation Factor	Total Utility	North Dakota Jurisdiction	Allocation Factor
1	Demand	73,048,139	4,223,660	5.7820%
2	Energy	37,726,342	2,217,924	5.8790%
3	Customers	1,377,264	85,722	6.2241%
4	Two-Factor			5.9458%

(1) Demand
(2) Energy
(3) Average number of Customers
(4) Two-Facot Allocator (A&G Only) See page 3
Expressed as an equally weighted factor based on electric plant in service and electric O&M expense (excluding A&G). These costs are then allocated to jurisdiction based on the O&M default for that Regulatory Business Unit.
The production and tranmission portions are allocated to jurisdiction using a 12 CP demand allocator, and the customer portion is allocated using 12- month end-of-year average electric customers.

Alloctors for Common and General Plant
for 2008 Budget
Based on 2006 Actual Data

O&M Allocator

O&M excluding A&G	2006 Actuals	Ratio
Production	$ 380,439,769	60.72%
Transmission	$ 26,661,082	4.26%
Distribution/Customer	$ 219,456,001	35.03%
	$ 626,556,852	100.00%

Plant in Service used to allocate Electric General Plant
Source - 2006 FERC Form 1
Pages 204-207

	2006 Year End Balance	Ratio
Production	$ 4,182,632,295	52.06%
Transmission	$ 1,212,672,560	15.09%
Distribution	$ 2,639,294,906	32.85%
	$ 8,034,599,761	100.00%

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

Production	56.3884%
Transmission	9.6742%
Distribution	33.9374%
	100.0000%

06 Budget Allocators

EProd Demand Alloc

MN	86.9819%
ND	5.8028%
SD	5.3463%
WHLSL	1.8690%
	100.0000%

ETrans Demand Alloc

MN	86.9819%
ND	5.8028%
SD	5.3463%
WHLSL	1.8690%
	100.0000%

ECustomerMN/SD/ND

MN	88.0585%
ND	6.2241%
SD	5.7164%
WHLSL	0.0010%
	100.0000%

2008 Budget A&G Jurisdicational Allocators

ELECTRIC A&G Alloc

2 Factor Allocator	O&M and Plant	MN	ND	SD	WHLSL	Check
Production	56.3884%	49.0477%	3.2721%	3.0147%	1.0539%	56.3884%
Transmission	9.6742%	8.4148%	0.5614%	0.5172%	0.1808%	9.6742%
Distribution/Customers	33.9374%	29.8848%	2.1123%	1.9400%	0.0003%	33.9374%
Resulting Allocator	**100.00%**	**87.3473%**	**5.9458%**	**5.4719%**	**1.2350%**	**100.0000%**

Line No.	Description	Allocation Basis
	The allocation factors on this page were used to determine North Dakota jurisdictional rate base amounts for all of the years presented in these schedules.	
	The following allocation factors are used to compute North Dakota jurisdictional amounts for Plant-in-Service, Accumulated Depreciation, Accumulated Deferred Income Tax and Construction Work in Progress:	
1	Production	Demand/Energy
2	Transmission	Demand
3	General	Demand/Customers/Direct Assigned
	Production	
	Transmission	
	Other	
4	Common	Demand/Customers/Direct Assigned
	Production	
	Transmission	
	Other	
	In addition, the following allocation factors are used to compute North Dakota jurisdictional amounts:	
5	TBT Investment	Customers
6	Other Rate Base:	
	Materials & Supplies	Demand/Customers/Direct Assigned
	Non-Plant Assets & Liabilities	Demand/Customers/Direct Assigned
	Prepayments	Demand/Customers/Direct Assigned
	Fuel Inventory	Energy

		Test Year 2008		
Line No.	Allocation Factor	Total Utility	North Dakota Jurisdiction	Allocation Factor
1	Demand	73,048,139	4,223,660	5.7820%
2	Energy	37,726,342	2,217,924	5.8790%
3	Customers	1,377,264	85,722	6.2241%

(1) Demand
(2) Energy
(3) Average number of Customers

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Average Rate Base
($000's)

Case No. PU-07-____
Exhibit ___ (AEH-1)
Schedule 14, Page 1 of 2

Line No.	Description	Average Rate Base (A)
	Electric Plant as Booked	
1	Production	$356,704
2	Transmission	87,557
3	Distribution	124,202
4	General	14,538
5	Common	24,338
6	TBT Investment	0
7	TOTAL Utility Plant in Service	$607,339
	Reserve for Depreciation	
8	Production	$234,339
9	Transmission	29,941
10	Distribution	48,239
11	General	6,955
12	Common	13,692
13	TOTAL Reserve for Depreciation	$333,166
	Net Utility Plant in Service	
14	Production	$122,365
15	Transmission	57,616
16	Distribution	75,964
17	General	7,583
18	Common	10,646
19	TBT Investment	0
20	Net Utility Plant in Service	$274,173
21	Utility Plant Held for Future Use	$0
22	Construction Work in Progress	$4,802
23	Less: Accumulated Deferred Income Taxes	$40,717
24	Cash Working Capital	$1,136
	Other Rate Base Items:	
25	Materials and Supplies	$5,412
26	Fuel Inventory	2,358
27	Non-Plant Assets & Liabilities	(6,928)
28	Prepayments	1,127
29	Customer Advances	(60)
30	Other Working Capital	797
31	Total Other Rate Base Items	$2,706
32	Total Average Rate Base	$242,100

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Comparison of Detail Rate Base
($000's)

Case No. PU-07-____
Exhibit ___ (AEH-1)
Schedule 14, Page 2 of 2

		Proposed Test Year 2007					
		Total Utility			North 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	$6,122,168	$0	$6,122,168	$356,704	$0	$356,704
2	Transmission	1,512,383	0	1,512,383	87,557	0	87,557
3	Distribution	2,809,833	342	2,810,175	123,860	342	124,202
4	General	243,395	0	243,395	14,538	0	14,538
5	Common	404,711	0	404,711	24,338	0	24,338
6	TBT Investment	0	0	0	0	0	0
7	TOTAL Utility Plant in Service	$11,092,490	$342	$11,092,832	$606,997	$342	$607,339
	Reserve for Depreciation						
8	Production	$4,056,697	$0	$4,056,697	$234,339	$0	$234,339
9	Transmission	519,244	0	519,244	29,941	0	29,941
10	Distribution	1,098,999	5	1,099,004	48,234	5	48,239
11	General	116,687	0	116,687	6,955	0	6,955
12	Common	227,197	0	227,197	13,692	0	13,692
13	TOTAL Reserve for Depreciation	$6,018,823	$5	$6,018,828	$333,161	$5	$333,166
	Net Utility Plant in Service						
14	Production	$2,065,472	$0	$2,065,472	$122,365	$0	$122,365
15	Transmission	993,139	0	993,139	57,616	0	57,616
16	Distribution	1,710,835	337	1,711,172	75,626	338	75,964
17	General	126,708	0	126,708	7,583	0	7,583
18	Common	177,514	0	177,514	10,646	0	10,646
19	TBT Investment	0	0	0	0	0	0
20	Net Utility Plant in Service	$5,073,667	$337	$5,074,004	$273,836	$338	$274,173
21	Utility Plant Held for Future Use	$0	$0	$0	$0	$0	$0
22	Construction Work in Progress	$358,070	$0	$358,070	$4,802	$0	$4,802
23	Less: Accumulated Deferred Income	$773,970	$4	$773,974	$40,713	$4	$40,717
24	Cash Working Capital	$8,642	$3,697	$12,339	$951	$185	$1,136
	Other Rate Base Items:						
25	Materials and Supplies	$92,681	$0	$92,681	$5,412	$0	$5,412
26	Fuel Inventory	40,111	0	40,111	2,358	0	2,358
27	Non-Plant Assets & Liabilities	(116,839)	0	(116,839)	(6,928)	0	(6,928)
28	Prepayments	18,264	0	18,264	1,127	0	1,127
29	Customer Advances	(146)	0	(146)	(60)	0	(60)
30	Other Working Capital	12,237	0	12,237	797	0	797
31	Total Other Rate Base Items	$46,308	$0	$46,308	$2,706	$0	$2,706
32	Total Average Rate Base	$4,712,717	$4,030	$4,716,747	$241,582	$519	$242,100