

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-\_\_\_\_  
Exhibit\_\_\_\_

**Overall Revenue Requirements**  
**Rate Base**  
**Income Statement**

December 7, 2007

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1 I. INTRODUCTION AND QUALIFICATIONS

2

3 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

6

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

8 A. I am the Manager of Revenue Analysis for Xcel Energy Services Inc. (“XES”  
9 or the “Service Company”).

10

11 Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

12 A. I have over thirty-two years of employment experience with Northern States  
13 Power Company, a Minnesota corporation (“Xcel Energy” or the  
14 “Company”). My qualifications and experience are summarized in my resume  
15 provided with my testimony as Exhibit\_\_(AEH-1), Schedule 1.

16

17 Q. FOR WHOM ARE YOU TESTIFYING?

18 A. I am testifying on behalf of Xcel Energy, operating in North Dakota.

19

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

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

27

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

3 A. Yes they were.  
4

5 **II. DATA PROVIDED AND SELECTION OF TEST YEAR**  
6

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

9 A. Financial data is provided for the most recent fiscal year, that being calendar  
10 year 2006, and the test year selected, calendar year 2008.  
11

12 Financial data for the most recent fiscal year and the test year are adjusted for  
13 traditional regulatory adjustments (*e.g.* advertising expenses, economic  
14 development, etc.). The test year on which the Notice is based starts with  
15 financial data included in the Company's 2008 projected fiscal year budget,  
16 and includes ratemaking adjustments deemed necessary, along with  
17 refinements and corrections to 2008 budgeted data. These changes to the  
18 base data were made to assure appropriateness for purposes of developing a  
19 test year that provides a normalized level of rate base and expenses to  
20 establish just and reasonable rates. Separate rate base and income statement  
21 bridge schedules that identify test period adjustments are provided with my  
22 testimony as Exhibit\_\_(AEH-1), Schedule 5.  
23

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

26 A. Calendar year 2008 was selected as the test year for this filing using Xcel  
27 Energy's first-year budget data. The test year is based on the most recent

1 available budget information that is deemed appropriate for ratemaking  
2 purposes.

3  
4 Q. DOES THE 2008 PROJECTED TEST YEAR MEET THE COMMISSION'S  
5 REQUIREMENTS?

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

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

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

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

21  
22 I provide a comparison of past budgets to actual costs later in my testimony  
23 in compliance with the first requirement of this statute. The 2008 Company  
24 budget data, as adjusted for the known and measurable changes discussed  
25 below, is a reasonable representation of the costs and rate case expense the  
26 Company will incur to provide electric service in the State of North Dakota,  
27 and complies with NDCC § 49-05-04.1, subd. 2. Thus, the 2008 test year data

1 is reasonable, reliable and made in good faith and is appropriate for setting  
2 rates in this proceeding. In addition, the accounting treatment applied to  
3 anticipated events and transactions in the budget is the same as the  
4 accounting treatment applied in recording the events once they have  
5 occurred.

6  
7 Q. NDCC § 49-05-04.1, Subd. 1(b) REQUIRES A UTILITY TO FILE "HISTORIC  
8 PERIOD" DATA. HOW IS XCEL ENERGY COMPLYING WITH THIS  
9 REQUIREMENT?

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

14  
15 Q. PLEASE EXPLAIN WHY IT WAS NECESSARY TO UPDATE THE 2006 ACTUAL  
16 JURISDICTIONAL INFORMATION PROVIDED TO THE COMMISSION IN MAY  
17 2007?

18 A. In July of 2007, a data error was discovered relative to data included in the  
19 2006 actual 12 coincident peak demand allocators ("demand allocators"). The  
20 error occurred in the South Dakota jurisdictional data recorded during the last  
21 quarter of 2006. The demand allocators are used to allocate fixed production  
22 and transmission investments and expenses. The North Dakota jurisdictional  
23 demand factors used to prepare the May 1 report were 6.0657 percent for  
24 Production investment and expenses and 5.9493 percent for Transmission  
25 investment and expenses. The Company corrected the data and recalculated  
26 the 2006 actual demand allocators for the total operating utility company (the  
27 "Company"). The corrected factors for the North Dakota electric retail

1 jurisdiction are 6.0176 percent for Production investment and expenses and  
2 5.9020 percent for Transmission investment and expenses, a decrease of  
3 0.0481 percent and 0.0473 percent, respectively.  
4

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

7 A. After applying the corrected factors for this minor difference in North  
8 Dakota demand, the overall North Dakota jurisdictional revenue deficiency  
9 fell by \$186,000 to \$5,376,000.  
10

### 11 III. TEST YEAR BUDGET DEVELOPMENT

12

13 Q. DESCRIBE THE TEST YEAR BUDGET PROCESS.

14 A. The budgeting process for the 2008 test year began in early March 2007 with  
15 the issuing of Budget Guidelines and Instructions to the various business  
16 areas for the 2008 budget preparation. The test year budget is assembled  
17 separately by its various components: Sales Forecast (customers and  
18 consumption), Retail and Other Revenues, Cost of Production, Operating and  
19 Maintenance ("O&M") Expenses, Capital Invested, Other Rate Base  
20 Investment and Capital Structure Components. The various budgets are  
21 submitted to the Finance Council for review. All final O&M, labor and  
22 capital expenditure budgets are submitted to the Board of Directors for  
23 review and approval. Management will use the final budget, as approved, to  
24 monitor and manage the Company's operations and financial performance  
25 during 2008.  
26

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

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

7  
8 Each business area is responsible for appropriate Federal Energy Regulatory  
9 Commission ("FERC") designation of its budgeted O&M dollars.  
10 Accounting codes in the J.D. Edwards ("JDE") general ledger accounting  
11 system determine the FERC account to which budgeted costs apply. Each  
12 JDE business unit contains the necessary information to determine the  
13 appropriate FERC account classification. In addition, the business areas are  
14 responsible for including a location code where appropriate. This  
15 information helps facilitate appropriate utility and jurisdictional cost  
16 assignment.

17  
18 Q. YOU MENTIONED THAT YOU MADE ADJUSTMENTS TO THE 2008 BUDGET FOR  
19 CERTAIN TRADITIONAL REGULATORY ADJUSTMENTS. PLEASE DESCRIBE  
20 THESE ADJUSTMENTS.

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

- 24 1) Advertising Expenses
- 25 2) Economic Development Costs
- 26 3) Interest on Customer Deposits
- 27 4) Professional Association and Utility Association Dues

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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

- 1 (termed MISO Network Revenue Adj. on Exhibit \_\_\_\_ (AEH-1) Schedule  
2 3).
- 3 2) King Chemicals Adjustment – The 2008 O&M budget included only the  
4 North Dakota, South Dakota, Wholesale and NSP-Wisconsin portion of  
5 costs for the chemicals needed to run the newly installed pollution  
6 control equipment at the Company’s A. S. King generating plant.  
7 Because the Minnesota Public Utilities Commission (“MPUC”) granted  
8 deferred accounting for the Minnesota portion of these costs in Docket  
9 No. E002/M-06-1315, the Minnesota portion of the total cost was  
10 budgeted to a deferred account rather than to an O&M account. The  
11 process used to allocate the remaining King chemical costs to all of the  
12 Company’s jurisdictions, including Minnesota. Because no costs should  
13 have been allocated to Minnesota, an adjustment was made to correct the  
14 cost assignment.
- 15 3) Tree Trimming Adjustment – The processes used to assign distribution  
16 costs to the appropriate jurisdiction utilizes a code attached to the  
17 budget account to determine the jurisdictional cost assignment. We  
18 discovered a coding error during our data review process that  
19 inadvertently assigned the tree trimming budgeted for the North Dakota  
20 jurisdiction to South Dakota. Therefore, an adjustment was made to  
21 exclude the cost from South Dakota expense and include the cost in  
22 North Dakota jurisdictional distribution expense.
- 23 4) MISO Schedule 16 and 17 Reclassification between FERC accounts –  
24 During the data review process we discovered that MISO Schedule 16  
25 and 17 Day 2 administrative expenses were budgeted to FERC account  
26 565 (Transmission of Electricity by Others), rather than FERC Account  
27 575.7 (Market Administration, Monitoring and Compliance Services).

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

3           5) Remaining Life Adjustment - As a part of the Company's 2007 Annual  
4           Review of Remaining Lives filing with the MPUC, the Company  
5           requested approval of an extended life for the Monticello nuclear  
6           generating plant, as well as changes to several other small generating  
7           facilities. At the time the 2008 capital budget was prepared, there had  
8           not yet been a decision from the MPUC granting approval of the  
9           Company's request. Therefore, the budget was prepared assuming an  
10          effective date of January 1, 2008 for the extended lives of these facilities.  
11          However, on September 21, 2007 the MPUC issued its order approving  
12          the change in remaining lives effective January 1 2007. To correct the  
13          2008 beginning balances to reflect the implementation of the MPUC  
14          order, we reduced the accumulated reserve for depreciation for  
15          Monticello by \$1,490,000 and the other plants by \$45,000 for the North  
16          Dakota jurisdiction. In addition, we increased the accumulated deferred  
17          income taxes for Monticello by \$609,000 and the other plants by  
18          \$18,500 for the North Dakota jurisdiction.

19

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

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

26

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

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

11

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

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

26

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

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

5

6 Q. HAVE THERE BEEN ORGANIZATIONAL AND OTHER CHANGES THAT HAVE  
7 AFFECTED THE JURISDICTIONAL ASSIGNMENTS AND ALLOCATIONS?

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

15

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

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

21

22 **IV. TEST YEAR REVENUE DEFICIENCY**

23

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

26 A. The jurisdictional retail revenue requirement for North Dakota electric utility  
27 operations is \$167,714,000 based on average rate base and projected net

1 operating income for the 2008 test year, the average capital structure, short-  
2 term debt, long-term debt and 11.5 percent cost of equity, based on the return  
3 on equity recommended by Dr. James Vander Weide in his Direct Testimony  
4 filed with this Notice.

5

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

7 A. The amount of the revenue deficiency for the test year is \$20,535,000. A  
8 summary of the revenue deficiency is shown in Exhibit \_\_\_ (AEH-1), Schedule  
9 7 as a comparison of the jurisdictional revenue requirement amount for the  
10 test year with the forecasted revenues for the same period under present rates  
11 which were approved by the Commission in Case No. PU-400-92-399. The  
12 level of North Dakota retail electric rates must be increased by this amount in  
13 order to earn an overall return on rate base of 9.20 percent as developed in  
14 Exhibit \_\_ (AEH-1), Schedule 8, page 5.

15

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

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

21

	<u>Rate</u>	<u>Ratio</u>	<u>Weighted Cost</u>
22 Long Term Debt	6.79%	45.61%	3.10%
23 Short Term Debt	5.74%	2.62%	0.15%
24 Common Equity	11.50%	51.77%	<u>5.95%</u>
25 Weighted Cost			9.20%

26

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

3

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

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

13

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

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

18

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

21   A. Yes. The Company files annual and quarterly 10K and 10Q statements with  
22       the Securities and Exchange Commission ("SEC"). These SEC filings disclose  
23       and reflect the Company's actual capital structure. The Company's actual  
24       capital structure is significant to its financial risk. Investors in the Company's  
25       publicly traded debt securities and the credit rating agencies have relied on the  
26       Company's actual capital structure, as reflected in these SEC filings. As a  
27       result, the use of the combination of: (i) the Company's separate capital

1 structure; and (ii) the Company's separate costs of long-term debt and short-  
2 term debt is supported by the regulatory principle of matching.

3

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

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

9

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

12 A. Yes, under my direction, a cost of service study was prepared.  
13 Exhibit\_\_\_(AEH-1), Schedule 8 contains a copy of the jurisdictional cost of  
14 service study.

15

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

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

1

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

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

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

16

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

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

1 67, 1.5 MW wind turbines over approximately 40 square miles and is expected  
2 to be in service by the end of 2008 at a total cost of approximately \$ 223.8  
3 million.

4  
5 Q. WHAT INCREASE HAS THERE BEEN IN THE COMPANY'S TRANSMISSION PLANT  
6 INVESTMENT?

7 A. As described in Mr. Walter Grivna's Direct Testimony, the Company has  
8 made significant investment in transmission plant in three separate groups:  
9 system performance, generation investments and wind supporting  
10 transmission investments. Exhibit 1 to Mr. Grivna's Direct Testimony breaks  
11 out the amount of investment in each category for the period 2004 through  
12 2008. In total, the Company added approximately \$484.3 million in  
13 transmission investment since the 2005 actual year, resulting in an increase in  
14 rate base of approximately \$21.4 million for the North Dakota jurisdiction.

15  
16 Q. WHAT ARE THE ELEMENTS OF CAPITAL RECOVERY?

17 A. The elements of capital recovery are: (i) depreciation, which is the ratable  
18 return of investment over its estimated service life; (ii) return on investment;  
19 and (iii) related income taxes. Depreciation expense has increased by  
20 \$1,226,000 since 2005. This expense is driven by the increase in utility plant  
21 investment, including significant investment in our generating facilities and  
22 transmission system. The increase in Depreciation expense related to the  
23 increase in utility plant is partially offset by the extended life of our Monticello  
24 nuclear generating plant. Since 2005, utility plant in-service investment  
25 allocated to the North Dakota jurisdiction has increased by over \$98.4  
26 million.

27

- 1 Q. HOW WAS DEPRECIATION EXPENSE AFFECTED BY THE LIFE EXTENSION OF  
2 THE MONTICELLO NUCLEAR GENERATING FACILITY?
- 3 A. In Docket No. E,G002/D-07-251, the MPUC extended the life of the  
4 Monticello nuclear generating by 20 years to 2030. This change in life is  
5 consistent with the October 23, 2006 MPUC Order granting a Certificate of  
6 Need for spent fuel storage needed to operate the plant an additional 20 years  
7 beyond 2010. The extended life of this facility decreased annual Depreciation  
8 expense for the Company by \$25.8 million, or approximately \$1.5 million for  
9 the North Dakota electric jurisdiction.
- 10
- 11 Q. ARE THERE OTHER COST ELEMENTS RELATED TO THE AMOUNT OF UTILITY  
12 PLANT IN-SERVICE INVESTMENT?
- 13 A. Yes. Real estate and personal property taxes are directly related to utility plant  
14 in-service investment. Increases in real estate and personal property taxes  
15 result from additional investment in plant and facilities and from higher  
16 assessment levels by taxing authorities. As a result, the revenue requirement  
17 for real estate and property taxes has increased by \$764,000 since 2005.
- 18
- 19 Q. PLEASE DISCUSS THE COMPONENTS OF YOUR CALCULATION OF "GROSS  
20 MARGIN GROWTH" SHOWN ON EXHIBIT\_\_\_\_(AEH-1), SCHEDULE 9, PAGE 1,  
21 LINE 9.
- 22 A. This line item shows the change in retail operating income from the 2005  
23 actual year to the 2008 test year. The level of kilowatt-hour sales has  
24 increased since 2005, thereby causing an increase in retail operating income,  
25 which has provided a partial offset to some of the effects of increasing costs  
26 of operations. This change is derived from the addition of new customers, as  
27 well as any changes in use per customer.

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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

1 procedures currently in place, it is not expected to dramatically affect the NSP  
2 Companies' share of MISO transmission revenue, assuming that all load  
3 under the MISO Transmission and Energy Markets Tariff ("TEMT") is billed  
4 for transmission service. However, because of an unexpected situation, there  
5 is potential for over \$61 million of revenue reallocation among MISO  
6 transmission owners.

7

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

9 A. When Ameren joined MISO as a Transmission Owner, a Stipulation  
10 agreement was filed between Ameren, the Missouri Commission and MISO,  
11 prohibits MISO from billing Ameren bundled load in Missouri until October  
12 2009. However, if Ameren collects its share of total revenues based on its  
13 revenue requirement, but does not pay for network service for its bundled  
14 load in Missouri, the other owners would be shorted approximately \$61  
15 million per year in revenue.

16

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

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

21

22 Q. UNDER WHAT CONDITIONS WILL THIS SHORTFALL OCCUR?

23 A. If MISO moves to the new revenue distribution procedures, the shortfall will  
24 occur. However, since this shortfall is an unforeseen consequence that was  
25 not intended to occur after the MISO Transition Period ended, almost all  
26 transmission Owners but Ameren are sponsoring a tariff change to solve the  
27 problem by having MISO impute the unbilled revenues before calculating

1 revenue distribution shares. While most transmission owners expect FERC  
2 to approve this change effective February 1, 2008, there is some chance that  
3 the revenue shortfall will happen if FERC fails to approve the tariff change.

4

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

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

11

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

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

17

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

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

23

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

1 A. Revenues for the provision of transmission service included in other electric  
2 operation revenues are related to a majority of the expense included in  
3 transmission of energy by others. Therefore, this transmission expense was  
4 included in the determination of the gross margin rather than O&M expense.  
5

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

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

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

14 A. The main reason for the increase in costs associated with electric generating  
15 facilities is an increase in nuclear operating expenses. The increase in cost  
16 from 2005 to the 2008 budget is approximately \$68.8 million for the  
17 Company and \$3,748,000 for the North Dakota electric retail jurisdiction.  
18 The reasons for this increase are discussed in detail in the testimony of Mr.  
19 Charles Bomberger.  
20

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

24 A. Currently, the Company uses the direct-expense method for the costs  
25 associated with reloading the nuclear reactors with fuel, which are incurred  
26 during refueling outages at our three nuclear plants. Since the number of  
27 refueling outages scheduled in any given year will vary, with two outages

1 occurring in most years, one in other years, and the potential for even three  
2 refueling outages occurring in some years, the expenses associated with these  
3 outages will also swing significantly from year to year. We have filed a  
4 separate request with the Commission to approve a deferral-and-amortization  
5 method under which refueling costs would be deferred and amortized during  
6 the period between refueling outages, as opposed to being expensed in the  
7 year that the costs are incurred. The deferral method would produce nearly  
8 identical expense levels to those requested in the test year (deferral would  
9 reduce the expense by approximately \$173,000).

10

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

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

23

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

26 A. Currently, the Company is requesting recovery of \$2,492,000 in refueling  
27 outage related expenses for the 2008 test year based on the direct expense

1 methodology. This amount reflects two scheduled outages in 2008, both at  
2 the Prairie Island plant, Units 1 & 2. If approved by the Commission, under  
3 the deferral-and-amortization methodology, the Company would record  
4 amortized refueling outage expenses of \$812,000 in 2008, which would not  
5 reflect the ongoing expense level, but rather the start-up amortization amount  
6 at its lowest point in which not all of the plants have been through a refueling  
7 outage. The amortized North Dakota jurisdictional expense amount that  
8 represents a more normal level of expense, reflecting a full cycle of refueling  
9 outages, is \$2,319,000.

10  
11 If the Commission approves our separate application to use the deferral  
12 method, the Company proposes using a normalized fuel outage expense of  
13 \$2,319,000 in the rate case test year, thereby reducing the requested increase  
14 by \$173,000. The Company believes this rate case provides an opportune  
15 time to implement this accounting change in North Dakota, allowing new  
16 rates to be established at more normal levels.

17  
18 Q. HAVE THERE BEEN OTHER REASONS FOR INCREASED COSTS AT THE  
19 COMPANY'S ELECTRIC GENERATING FACILITIES?

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

27

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

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

12

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

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

22

23

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27



1 "Revenue Requirement and Return Summary" for total Company electric  
2 operations and the North Dakota jurisdiction. Specifically, the schedule  
3 shows the calculated earned overall rate of return on rate base, calculated  
4 earned rate of return on common stock equity capital, the revenue deficiency  
5 that needs to be recovered to enable the North Dakota jurisdiction electric  
6 operations to earn the requested return on common equity and finally, the  
7 total revenue requirements and the percent of increase that would result by  
8 increasing retail billing rates by the amount of the revenue deficiency. The  
9 computation of cash working capital, Schedule 8, Page 6, is carried back to  
10 the rate base on Schedule 8, Page 2.

11

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

14 A. Yes. The revenue conversion factor calculation is included in my exhibits at  
15 Exhibit\_\_\_(AEH-1), Schedule 10.

16

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

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

23

24 Q. DESCRIBE THE SCHEDULE IN YOUR EXHIBIT THAT IS RELATED TO THE INCOME  
25 STATEMENT.

26 A. Exhibit\_\_\_ (AEH-1) Schedule 11, Page 1 of 2, is a comparative income  
27 statement for the 2008 test year showing the income effect of present

1 authorized rates and proposed rates. This comparative income statement was  
2 prepared from the results of the jurisdictional cost of service study and  
3 includes the revenue deficiency in the North Dakota jurisdiction electric utility  
4 operations. Schedule 11, Page 2 of 2, shows an electric utility comparative  
5 income statement for the North Dakota jurisdiction and total Company for  
6 the 2008 test year before making test period adjustments. The operating  
7 income statement after making the proposed test period adjustments is also  
8 shown on Page 2 of 2.

## 9 10 VI. UTILITY AND JURISDICTIONAL ALLOCATIONS

11  
12 Q. PLEASE DESCRIBE THE METHODS USED TO ALLOCATE COSTS TO THE  
13 COMPANY'S ELECTRIC UTILITY OPERATIONS.

14 A. The test year includes both costs incurred directly by the Company's electric  
15 operating business and costs directly assigned or allocated by the Service  
16 Company for corporate functions (*e.g.*, accounting, human resources, law,  
17 etc.). The Service Company cost allocation and billing process is subject to  
18 FERC jurisdiction and authorization under a Utility Services Agreement  
19 between Xcel Energy and the Service Company. O&M cost assignments and  
20 allocations were the same as used by the Company in the recent Minnesota  
21 electric rate case filed with the MPUC (MPUC Docket No. E002/GR-05-  
22 1428). Non-O&M costs include such items as book depreciation expense,  
23 deferred income taxes and property taxes. All of the common investments  
24 and their related costs, be it software or other common investments and  
25 expenses, are evaluated as to whether the cost should be direct assigned to  
26 Electric or Gas, or allocated based on appropriate allocators such as:

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

3

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

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

13

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

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

27

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

3 A. The Company's production and transmission system is designed, built, and  
4 operated to provide an integrated source of electricity shared by the  
5 Company's electric customers first between the Company and NSP-Wisconsin  
6 operating companies through the Interchange Agreement as approved by  
7 FERC and discussed later in my testimony. The Company's portion of costs  
8 is then shared among customers in North Dakota, Minnesota and South  
9 Dakota, as well as a group of wholesale customers with rates regulated by  
10 FERC. To determine the level of investment associated with the provision of  
11 electric service to North Dakota retail customers, it is necessary to assign or  
12 allocate a portion of the total production and transmission investment to each  
13 jurisdiction. We used each jurisdiction's respective coincident peak demands  
14 for electricity as the basis for this allocation. It is reasonable to use coincident  
15 peak demands as an allocation basis because these facilities are designed to  
16 meet peak requirements and operate as an integrated system across all  
17 jurisdictions. This is consistent with the methodology accepted in the last  
18 North Dakota electric rate cases, Case No. PU-400-92-399, and reflects the  
19 fact that these facilities have been designed to meet peak requirements.

20

21 Q. HOW WERE THE DISTRIBUTION INVESTMENT AMOUNTS ASSIGNED TO THE  
22 NORTH DAKOTA JURISDICTION?

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

26

1 **VII. RATE BASE COMPONENTS**

2

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

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

8

9 Q. PLEASE EXPLAIN WHAT RATE BASE REPRESENTS.

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

14

15 Q. PLEASE IDENTIFY THE MAJOR COMPONENTS OF THE PROJECTED TEST YEAR  
16 RATE BASE.

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

- 19 • Net Utility Plant  
20 • Short-term Construction Work in Progress  
21 • Accumulated Deferred Income Taxes  
22 • Other Rate Base Items

23

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

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

9

10 **VIII. NET UTILITY PLANT**

11

12 Q. WHAT DOES NET UTILITY PLANT REPRESENT?

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

16

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

19 A. The net utility plant is included in rate base at depreciated original cost  
20 reflecting the simple average of projected net plant balances at the beginning  
21 and end of the test year. Such treatment is consistent with the method  
22 employed in the most recent North Dakota electric rate case, Case No. PU-  
23 400-92-399.

24

25 Q. WHAT HISTORICAL BASE DID XCEL ENERGY RELY ON AS A STARTING POINT TO  
26 DEVELOP THE PROJECTED NET PLANT BALANCES FOR THE BEGINNING OF THE  
27 TEST YEAR?

1 A. The historical base used was Xcel Energy's actual net investment (Plant in  
2 Service less Accumulated Depreciation) on the books and records of the  
3 Company as of May 31, 2007.

4

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

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

11

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

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

19

20 **IX. CONSTRUCTION WORK IN PROGRESS**

21

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

24 A. Yes. The only CWIP that is included in rate base are costs related to projects  
25 of a short-duration that do not accrue Allowance for Funds Used During  
26 Construction ("AFUDC"). Thus, there is no AFUDC offset added to  
27 operating income. The rate base amount reflects a simple average of

1 projected CWIP beginning and ending test year balances. This is consistent  
2 with the method employed in the most recent North Dakota electric rate case  
3 (Case No. PU-400-92-399) and matches the use of an average rate base.  
4

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

7 A. The beginning test year balance for CWIP was the May 31, 2007 historical  
8 balance. The beginning test year CWIP balance was adjusted to reflect  
9 projected construction expenditures, and transfers to Plant in Service during  
10 the 2008 test year to obtain the ending test year CWIP balance. These  
11 projections were developed from the Company's 2008 capital budget.  
12

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

15 A. As shown on Exhibit\_\_\_\_(AEH-1), Schedule 8, Page 2, the average short-term  
16 CWIP included in rate base was \$4,802,000.  
17

## 18 X. ACCUMULATED DEFERRED INCOME TAXES

19  
20 Q. PLEASE DESCRIBE ACCUMULATED DEFERRED INCOME TAXES ("ADIT").

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

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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

1 various non-plant assets and liabilities. The net cash requirements, also  
2 referred to as Cash Working Capital, is shown separately.

3

4 Q. HOW HAVE TEST YEAR MATERIALS AND SUPPLIES AND FUEL INVENTORY  
5 REQUIREMENTS BEEN CALCULATED?

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

11

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

14 A. These balances as shown on Exhibit\_\_\_(AEH-1), Schedule 8, Page 2,  
15 represent the 2008 calendar year estimate of these balances. Any book/tax  
16 timing differences associated with these items has been reflected in the  
17 determination of current and deferred income tax provision and accumulated  
18 deferred tax balances previously discussed. This group is primarily comprised  
19 of liabilities that reduce test year rate base by \$6,928,000.

20

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

23 A. Items of Prepayments and Other Working Capital such as customer advances  
24 and deposits, are based on the actual thirteen-month average balances during  
25 the period ended May 31, 2007, as a proxy for the test year. The unamortized  
26 balances included in this section are based on the amortization schedules as  
27 described later in my testimony on revenue requirements. The net impact of

1 these various items increase test year rate base by \$1,864,000 as shown on  
2 Exhibit\_\_\_(AEH-1), Schedule 8, Page 2.

3

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

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

9

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

13 A. Yes.

14

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

17 A. A lead/lag study is a detailed analysis of the time periods involved in the  
18 utility's receipt and disbursement of funds. The study measures the difference  
19 in days between the date services to a customer are rendered and the revenues  
20 for that service are received, and the date the costs of rendering the services  
21 are incurred until the related disbursements are actually made. A positive net  
22 revenue lag means that, on average, Xcel Energy investors have provided cash  
23 working capital, and are entitled to a return thereon.

24

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

1 A. Yes. A new lead/lag study was prepared in 2004 for gas operations in  
2 conjunction with applications for gas general rate increases that were filed in  
3 North Dakota (Case No. PU-400-04-578) and Minnesota (Docket No.  
4 G002/GR-04-1511). The 2004 lead/lag study was expanded to include  
5 electric operations and the results were incorporated into the cash working  
6 capital calculations included in the 2005 Minnesota electric general rate  
7 increase application (Docket No E002/GR-05-1428). Many components of  
8 the lead/lag study associated with electric operations have been updated once  
9 more to reflect current experience. In cases where less significant items were  
10 not updated, we used revenue lag day or expense lead day values as filed in the  
11 2005 Minnesota electric rate case. The results of the updated lead/lag study  
12 for electric operations were incorporated into the North Dakota jurisdiction  
13 cash working capital calculations as shown on Exhibit (AEH-1), Schedule 8,  
14 Page 2.

15  
16 Q. WHAT IS THE TEST YEAR CASH WORKING CAPITAL AMOUNT?

17 A. The amount included in the average rate base is a positive \$1,136,000. The  
18 components of this amount are summarized in Exhibit\_\_\_(AEH-1), Schedule  
19 8, Page 6.

20  
21 Q. WHAT IS INDICATED BY THE POSITIVE CASH WORKING CAPITAL AMOUNT?

22 A. Positive cash working capital indicates overall revenue collections lag the date  
23 when the associated costs of service are paid. This means that, on average,  
24 cash working capital is being provided by the Company's investors. In the  
25 Company's circumstance, taxing authorities comprise the largest source of  
26 cash working capital as offsets to working capital provided by the Company's  
27 investors. Other sources of offsets may include customers, creditors and

1 employees. When a positive cash working capital exists, or is required, it is  
2 added to rate base to compensate the Company's investors for funds provided  
3 to meet cash working capital requirements.  
4

## 5 XII. ADJUSTMENTS TO RATE BASE

6

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

9 A. We made rate base adjustments to the 2008 budget for the: (i) Pole  
10 Inspection and Replacement Program; and (ii) Cable Replacement Program.  
11

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

14 A. These two adjustments are the result of business decisions that were made  
15 after the 2008 budget was established. The business decisions will result in  
16 increased costs that will occur in 2008 for these two programs, which are very  
17 important to the safe and reliable operation of our system.  
18

19 Q. WHAT IS THE POLE INSPECTION AND REPLACEMENT PROGRAM?

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

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

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

9

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

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

21

22

### XIII. INCOME STATEMENT

23

#### A. Revenues

24

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

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

3

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

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

8

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

12 A. Yes. The adjustment is consistent with the methodology in the last Xcel  
13 Energy North Dakota electric and natural gas rate cases (Case Nos. PU-400-  
14 92-399, PU-06-525).

15

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

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

22

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

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

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

6  
7 **B. Operating and Maintenance Expenses**

8  
9 Q. HOW DOES XCEL ENERGY DEVELOP ITS TEST YEAR PRODUCTION EXPENSE  
10 BUDGET?

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

24  
25 Q. PLEASE DESCRIBE THE INTERCHANGE AGREEMENT WITH NSP-WISCONSIN  
26 THAT YOU REFERENCED EARLIER.

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

10  
11 Q. PLEASE DESCRIBE THE COSTS ALLOCATED BETWEEN THE COMPANY AND  
12 NSP-WISCONSIN UNDER THE INTERCHANGE AGREEMENT.

13 A. Under the Interchange Agreement, the Company and NSP-Wisconsin share  
14 annual system generation (production) and transmission costs. Under the  
15 Interchange Agreement formulas, approximately 15 percent of the costs of  
16 the Company system are allocated to NSP-Wisconsin, and approximately 85  
17 percent of the NSP-Wisconsin system costs are allocated to the Company,  
18 because approximately 85 percent of the load on the integrated system is the  
19 Company load and 15 percent is NSP-Wisconsin load. The exact allocation  
20 percentages are determined by the allocation factors updated and filed at  
21 FERC annually. The Interchange Agreement also provides for an allocation  
22 of revenues received by the Company and NSP-Wisconsin, such as revenues  
23 from off-system wholesale sales. Interchange Agreement costs and revenues  
24 are budgeted by the Company and NSP-Wisconsin annually. Thus, the  
25 Company's budget shows Interchange Revenues -- revenues that reflect the  
26 charges to NSP-Wisconsin for its share of production and transmission assets  
27 and associated expenses. Likewise, Interchange Expense reflects the

1 Company's forecasted payments to NSP-Wisconsin for its proportionate  
2 share of the costs of generation and transmission assets and associated  
3 expenses incurred by NSP-Wisconsin to serve the system needs.  
4

5 **C. Depreciation Expense**  
6

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

9 A. Depreciation Expense for the test year reflects the depreciation rates last  
10 certified by the MPUC and is consistent with the ongoing practice followed  
11 by the Company in North Dakota rate case proceedings.  
12

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

15 A. Yes. I will address the effect of the Job Creation Act of 2004 and the  
16 treatment of lobbying expenses.  
17

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

20 A. This legislation provides for a production tax deduction on the income based  
21 on federal taxable income generated from the production portion of the  
22 Company. In order to reflect this deduction in the determination of the cost  
23 of service, I calculated our total income based on the amount of the revenue  
24 deficiency and allocated the appropriate percent to production as income  
25 (based on a functional separation of overall revenue requirements) using our  
26 proposed capital structure and 11.5 percent return on equity. I estimate that  
27 the value of the tax deduction is a reduction to the revenue requirements of

1 approximately \$97,000. This calculation will need to be revised after the  
2 Commission determines the final revenue requirement and rate of return, as  
3 these decisions will impact the test-year level of production income. The tax  
4 deduction is incorporated into the cost of service income tax determination  
5 and is not shown in the bridge schedule as an adjustment.

6  
7 Q. YOU ALSO MENTIONED LOBBYING. ARE ANY DOLLARS RELATED TO CIVIC OR  
8 POLITICAL ACTIVITIES (LOBBYING), IDENTIFIED IN THE COST OF SERVICE, OR  
9 ADJUSTMENTS?

10 A. No. Beginning in 1999, Northern States Power Company made a conscious  
11 effort to move all lobbying costs to below the line accounting, FERC account  
12 426.4, Expenditures for certain civic, political and related activities. Thus, no  
13 adjustment to the cost of service for lobbying is required, as these below the  
14 line amounts are not used in our development of the cost of service.

15  
16 **XIV. ADJUSTMENTS TO THE INCOME STATEMENT**

17  
18 Q. PLEASE IDENTIFY THE ADJUSTMENTS TO THE INCOME STATEMENT.

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

- 20 A. Interest on Customer Deposits;
- 21 B. Advertising Expenses
- 22 C. Incentive Compensation Adjustment
- 23 D. Economic Development Adjustment
- 24 E. Charitable Contributions
- 25 F. Saver's Switch Adjustment
- 26 G. Pole Inspection and Replacement Program
- 27 H. Cable Testing Program

- 1 I. Rate Case Expense Amortization
- 2 J. Renewable Development Fund Amortization
- 3 K. Private Fuel Storage Amortization
- 4 L. Asset Based Trading Margin Sharing
- 5 M. Non-Asset Based Trading Margin Sharing
- 6 N. MISO Schedule 16 and 17 Expense
- 7 O. Association Dues
- 8 P. Cash Working Capital

9  
10 A brief description of each income statement adjustment is provided below.

11

12 **A. Interest on Customer Deposits**

13

14 Q. HOW ARE CUSTOMER DEPOSITS TREATED IN THIS APPLICATION?

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

19

20 **B. Advertising Expenses**

21

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

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

1 Of the \$359,000 being excluded, the Company has excluded the entire Brand  
2 and Image advertising budget totaling \$232,000. This includes costs  
3 associated with television, print, radio and outdoor advertisement and is used  
4 by the Brand Advertising Department. This adjustment is reflected on  
5 Exhibit \_\_\_\_ (AEH-1), Schedule 3 and Exhibit \_\_\_\_ (AEH-1), Schedule 5, page  
6 2.

7  
8 **C. Incentive Compensation Adjustment**

9  
10 Q. PLEASE SUMMARIZE ADJUSTMENTS MADE TO THE TEST YEAR COST OF SERVICE  
11 TO EXCLUDE COSTS FOR PARTS OF THE COMPANY'S ANNUAL INCENTIVE  
12 COMPENSATION PROGRAMS.

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

24  
25 **D. Economic Development Adjustment**

26  
27 Q. PLEASE DESCRIBE THE ADJUSTMENT FOR ECONOMIC DEVELOPMENT COSTS.

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

6

7 **E. Charitable Contributions**

8

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

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

18

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

27

1           **F.       Saver's Switch Adjustment**

2  
3    Q.   PLEASE DESCRIBE THE ADJUSTMENT FOR SAVER'S SWITCH COSTS.

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

14  
15           **G.       Pole Inspection and Replacement Program**

16  
17    Q.   PLEASE DESCRIBE THE ADJUSTMENT FOR THE POLE INSPECTION AND  
18       REPLACEMENT PROGRAM.

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

23  
24           **H.       Cable Replacement Program**

25  
26    Q.   PLEASE DESCRIBE THE ADJUSTMENT FOR THE CABLE REPLACEMENT  
27       PROGRAM.

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

5  
6 **I. Rate Case Expense Amortization**

7  
8 Q. PLEASE EXPLAIN THE AMORTIZATION OF RATE CASE EXPENSE IN THIS  
9 PROCEEDING.

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

20  
21 **J. Renewable Development Fund**

22  
23 Q. PLEASE EXPLAIN THE AMORTIZATION OF RENEWABLE DEVELOPMENT FUND  
24 EXPENSE IN THIS PROCEEDING.

25 A. The Renewable Development fund ("RDF") amortization represents the  
26 North Dakota allocated portion of RDF grants awarded to Energy  
27 Production projects and budgeted to be paid in 2008. Before the MPUC

1 approves a grant award to an energy production project, a signed purchase  
2 power agreement must be approved. Energy produced from these projects  
3 also benefit North Dakota electric customers. Xcel Energy is not requesting  
4 recovery from North Dakota electric customers of RDF grant payments  
5 related to research and development projects, production incentives and other  
6 projects determined to benefit only Minnesota state customers. This  
7 adjustment is reflected on Exhibit \_\_\_\_ (AEH-1), Schedule 4 and Exhibit \_\_\_\_  
8 (AEH-1), Schedule 5, page 2.

9  
10 **K. Private Fuel Storage Amortization**

11  
12 Q. WHAT IS THE BASIS FOR THE COMPANY'S PROPOSAL TO RECOVER ITS EXPENSE  
13 IN PRIVATE FUEL STORAGE, LLC ("PFS")?

14 A. As explained by Mr. Bomberger in his Direct Testimony, Xcel Energy has  
15 expended approximately \$23 million in PFS in an effort to obtain a license  
16 from the Nuclear Regulatory Commission to develop a private independent  
17 spent fuel storage installation within the Goshute Indian tribal land in Utah.  
18 In Xcel Energy's last Minnesota electric rate case, the MPUC approved a six-  
19 year amortization of these costs beginning in 2006. The 2008 portion of the  
20 six-year amortization of investment for private fuel storage is \$3,279,000 or  
21 \$190,000 for the North Dakota jurisdiction. This adjustment is reflected on  
22 Exhibit \_\_\_\_ (AEH-1), Schedule 4 and Exhibit \_\_\_\_ (AEH-1), Schedule 5, page  
23 2.

1           **L.       Asset Based Trading Margin Sharing**

2  
3   Q.   PLEASE DESCRIBE THE ADJUSTMENT FOR THE SHARING OF ASSET BASED  
4       TRADING MARGINS.

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

12

13           **M.       Non-Asset Based Trading Margin Sharing**

14

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

17   A.   Also discussed in Mr. Krug's testimony is the sharing of 15 percent of the  
18       Company's non-asset based trading margins with North Dakota electric  
19       customers, including margins shared with Public Service Company of  
20       Colorado and Southwestern Public Service Company through the Joint  
21       Operating Agreement. We propose to retain the other 85 percent of these  
22       margins for our shareholders. Additionally, our proposal includes only the  
23       sharing of positive net margins. As was discussed with asset based trading  
24       margins, we propose here to share these margins with customers through the  
25       electric fuel clause recovery mechanism. The Company's last North Dakota  
26       electric rate case (filed in 1992 with a 1993 test year) did not include any non-  
27       asset based trading margins, as we did not actively participate in this type of

1 transaction at that time. This adjustment is reflected on Exhibit \_\_\_\_ (AEH-  
2 1), Schedule 4 and Exhibit \_\_\_\_ (AEH-1), Schedule 5, page 2.

3  
4 **N. MISO Schedule 16 and 17 Expenses**

5  
6 Q. PLEASE DESCRIBE THE ADJUSTMENT FOR MISO SCHEDULE 16 AND 17  
7 EXPENSES.

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

14  
15 When these costs were recovered from customers through the FCA, they  
16 were assigned to customers based on the energy allocator. However, for  
17 purposes of allocating these transmission related costs to the North Dakota  
18 electric jurisdiction for inclusion in base rates, we use the demand allocator.  
19 Because a different allocation method is used, there is a slight difference in  
20 the amount that would have been recovered from customers in revenue  
21 (\$532,000) and the amount of expense for base rate determination (\$522,000).  
22 Since the adjustment is to fuel clause revenues, we have excluded \$532,000, in  
23 fuel clause revenues but included an expense adjustment of \$522,000. This  
24 adjustment is reflected on Exhibit \_\_\_\_ (AEH-1), Schedule 4 and Exhibit \_\_\_\_  
25 (AEH-1), Schedule 5, page 2.

1       **O.       Association Dues**

2

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

5   A.   The Projected Year expense for organizational dues for the North Dakota  
6       electric jurisdiction is \$125,000, of which \$15,000 is for professional dues and  
7       \$110,000 is for dues related directly to the electric utility. All social, civic and  
8       political or chamber of commerce organization dues are booked below-the-  
9       line and are not included in Projected Year expense. Therefore, no  
10      adjustment was necessary.

11

12       **P.       Cash Working Capital**

13

14   Q.   PLEASE DESCRIBE THE CASH WORKING CAPITAL ADJUSTMENT

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

20

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

23   A.   Various test period adjustments that were made in the Income Statement to  
24       various functions of O&M expense have an effect on the amount of cash  
25       working capital that is required to conduct electric operations. For example,  
26       a change in current income tax would affect the amount of cash working

1 capital included in rate base. The results of the cash working capital  
2 computations are included in the Total Rate Base.

3

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

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

16

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

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

21

22

## XV. CONCLUSION

23

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

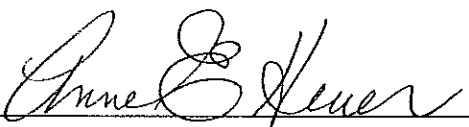
25 A. Yes, it does.

1 STATE OF NORTH DAKOTA  
2 BEFORE THE  
3 PUBLIC SERVICE COMMISSION  
4  
5

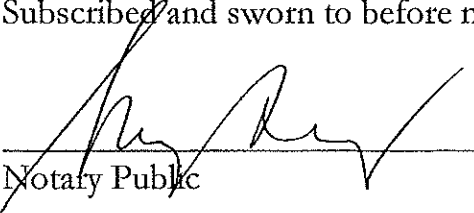
6 In the Matter of the Application of Northern )  
7 States Power Company, a Minnesota Corporation )  
8 For Authority to Increase Rates for Electric Service ) Case No. PU-07-\_\_\_\_  
9 in North Dakota )

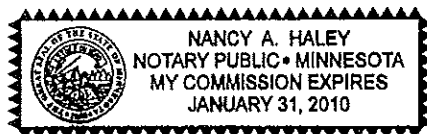
10  
11  
12  
13 **AFFIDAVIT OF**  
14 **Anne E. Heuer**  
15

16  
17 I, the undersigned, being duly sworn, depose and say that the foregoing is  
18 the Direct Testimony of the undersigned, and that such Direct Testimony and the  
19 exhibits or schedules sponsored by me to the best of my knowledge, information  
20 and belief, are true, correct, accurate and complete, and I hereby adopt said  
21 testimony as if given by me in formal hearing, under oath.  
22

23  
24   
25 Anne E. Heuer  
26

27  
28  
29  
30 Subscribed and sworn to before me, this 4 day of December, 2007.  
31

32  
33   
34 Notary Public  
35  
36



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

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### **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%**

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

**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

Case No. PU-07-\_\_\_\_  
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(Dollars in Thousands)

Rate Base Summary

	<u>Total Company Electric</u>			<u>North Dakota Retail Electric</u>			<u>All Other</u>		
	<u>Beginning Balance</u>	<u>Ending Balance</u>	<u>Average Balance</u>	<u>Beginning Balance</u>	<u>Ending Balance</u>	<u>Average Balance</u>	<u>Beginning Balance</u>	<u>Ending Balance</u>	<u>Average Balance</u>
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
<b>11 Total Rate Base</b>	<b>3,341,923</b>	<b>3,455,494</b>	<b>3,398,708</b>	<b>185,866</b>	<b>186,739</b>	<b>186,303</b>	<b>3,156,057</b>	<b>3,268,755</b>	<b>3,212,405</b>

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

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>	
<b><u>Operating Revenues</u></b>				
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	<b>Total Operating Revenues</b>	<b>3,349,532</b>	<b>180,637</b>	<b>3,168,895</b>
<b><u>Expenses</u></b>				
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	<b>Total Operating Expenses</b>	<b>2,382,611</b>	<b>134,375</b>	<b>2,248,237</b>
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	<b>Total Taxes</b>	<b>263,112</b>	<b>12,447</b>	<b>250,664</b>
24	<b>Total Expenses</b>	<b>3,029,070</b>	<b>166,244</b>	<b>2,862,826</b>
25	AFUDC	0	0	0
26	<b>Total Operating Income</b>	<b>320,462</b>	<b>14,393</b>	<b>306,069</b>

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

Case No. PU-07-\_\_\_\_  
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 Schedule 2, Page 4 of 6

(Dollars in Thousands)

Income Tax Summary

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>	
<b><u>Income Before Taxes</u></b>				
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	<b>Total Before Tax Book Income</b>	<b>460,806</b>	<b>20,210</b>	<b>440,596</b>
<b><u>Tax Additions</u></b>				
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	<b>Total Tax Additions</b>	<b>457,723</b>	<b>25,073</b>	<b>432,650</b>
<b><u>Tax Deductions</u></b>				
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	<b>Total Tax Deductions</b>	<b>575,018</b>	<b>30,574</b>	<b>540,166</b>
24	<b>State Taxable Income</b>	<b>343,512</b>	<b>14,710</b>	<b>328,802</b>
25	State Income Tax Rate	9.01%	7.00%	N/A
26	<b>Total State Income Taxes</b>	<b>30,947</b>	<b>1,030</b>	<b>29,918</b>
27	<b>Federal Taxable Income</b>	<b>312,565</b>	<b>13,680</b>	<b>298,885</b>
28	Federal Income Tax Rate	35.00%	35.00%	35.00%
29	<b>Total Federal Income Taxes</b>	<b>109,398</b>	<b>4,788</b>	<b>104,610</b>
30	<b>Total Federal &amp; State Income Taxes</b>	<b>140,345</b>	<b>5,818</b>	<b>134,527</b>

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

Case No. PU-07-\_\_\_\_  
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 Schedule 2, Page 5 of 6

**Revenue Requirement & Return Summary**

(Dollars in Thousands)

	<u>Capital Structure</u>	<u>Rate</u>	<u>Ratio</u>	<u>Weighted Cost</u>	<u>Composite Income Tax Rates</u>	
1	Long Term Debt	6.8300%	47.5765%	3.2400%	State of North Dakota Tax rate	7.00%
2	Short Term Debt	4.6100%	0.8352%	0.0400%	Federal Statutory Tax rate	35.00%
3	Preferred Stock	0.0000%	0.0000%	0.0000%	Federal Effective Tax Rate (1-State Rate * Fed Rate)	32.55%
4	Common Equity	12.0000%	51.5883%	6.1900%	<b>Total North Dakota Composite Tax Rate</b>	<b>39.55%</b>
5	<b>Required Rate of Return</b>			<b>9.4700%</b>	<b>Total Corporate Composite Tax Rate</b>	<b>40.86%</b>

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>
<b>Rate of Return (ROR)</b>			
6	Total Operating Income	320,462	14,393
7	Total Average Rate Base	3,398,708	186,303
8	<b>ROR (Operating Income / Rate Base)</b>	<b>9.43%</b>	<b>7.73%</b>
			<b>9.53%</b>

<b>Return on Equity (ROE)</b>			
9	Total Operating Income	320,462	14,393
10	Debt Interest (Rate Base * Weighted Debt Cost)	(111,478)	(6,111)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0
12	Earnings Available for Common	208,984	8,282
13	Equity Rate Base ( Rate Base * Equity Ratio)	1,753,336	96,111
14	<b>ROE (Earnings for Common / Equity Rate Base)</b>	<b>11.92%</b>	<b>8.62%</b>
			<b>12.11%</b>

<b>Revenue Deficiency</b>			
15	Require Operating Income (Rate Base * Required Return)	321,858	17,643
16	Operating Income	320,462	14,393
17	Operating Income Deficiency	1,396	3,250
18	Revenue Conversion Factor ( 1/(1-Composite Tax Rate) )	1.69079	1.65426
19	<b>Revenue Deficiency (Income Deficiency * Conversion Fac</b>	<b>2,360</b>	<b>5,376</b>
			<b>(3,016)</b>

<b>Total Retail Revenue Requirements</b>			
20	Retail Related Revenues	2,591,785	138,765
21	Revenue Deficiency	2,360	5,376
22	<b>Total Retail Revenue Requirements</b>	<b>2,594,145</b>	<b>144,141</b>
			<b>2,450,004</b>

23	<b>Percentage Increase (Decrease)</b>	<b>0.09%</b>	<b>3.87%</b>
			<b>-0.12%</b>

(Dollars in Thousands)

**Rate Base Detail - Cash Working Capital**

Expenses	Includable Expenses	Lead Days	Total Company Electric		ND Retail Electric		All Other	
			Dollars	Dollar x Days	Dollars	Dollar x Days	Dollars	Dollar x Days
<b>Fuel Expenses</b>								
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
<b>Purchased Power</b>								
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
<b>Labor &amp; Related Costs</b>								
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	146,873	0	2,596,656	0
22	Net Annual Expense Amount		0	0.00	0	0.00	0	0
<b>Revenues</b>								
23	Computer Billing	100.00%	2,591,289	0	138,765	0	2,452,524	0
24	Hand Billed	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	180,637	0	3,168,895	0
45	Net Annual Amount		0	0	0	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	Not 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

	<u>Adjustment Description</u>	<u>Adjustment Target</u>	<u>Total Co.</u>	<u>ND Juris.</u>	<u>Allocation Method</u>
1	Interchange Decommissioning	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	<u>6,774</u>	<u>392</u>	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	<u>(3,895)</u>	<u>(184)</u>	
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 Production	(12,639) 12,639	(731) 731	Demand Demand

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

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

red = updated

	<u>Adjustment Description</u>	<u>Adjustment Target</u>	<u>Total Co.</u>	<u>ND Juris.</u>	<u>Allocation Method</u>
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
	<u>Incentive Compensation</u>				
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		<u>22,007</u>	<u>304</u>	
	<u>Pole Inspection and Replacement Program</u>				
		<u>Rate Base</u>			
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
		<u>Income Statement</u>			
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
	<u>Cable Replacement Program</u>				
		<u>Rate Base</u>			
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
		<u>Income Statement</u>			
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)

Case No. PU-07-\_\_\_\_  
 Exhibit \_\_\_\_ (AEH-1)  
 Schedule 5, Page 2 of 4

Line No.	Description	2008 Base Data	Interest on Customer Deposits 1	Advertising 2	Incentive Pay 3	Economic Development 4	Charitable Contributions 5
<b>Operating Revenues</b>							
1	Retail	\$149,550					
2	CIP Revenue Adjustment	0					
3	Interdepartmental	0					
4	Other Operating	40,064					
5	Gross Earnings Tax	0					
6	<b>Total Operating Revenues</b>	<b>\$189,614</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>
<b>Expenses</b>							
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	<b>Total Operating Expenses</b>	<b>\$148,605</b>	<b>\$2</b>	<b>(\$359)</b>	<b>(\$322)</b>	<b>\$173</b>	<b>\$86</b>
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	<b>Total Taxes</b>	<b>\$10,224</b>	<b>(\$1)</b>	<b>\$141</b>	<b>\$126</b>	<b>(\$68)</b>	<b>(\$34)</b>
24	<b>Total Expenses</b>	<b>\$177,980</b>	<b>\$1</b>	<b>(\$218)</b>	<b>(\$196)</b>	<b>\$105</b>	<b>\$52</b>
25	Allowance for Funds Used During Construction	\$0					
26	<b>Total Operating Income</b>	<b>\$11,634</b>	<b>(\$1)</b>	<b>\$218</b>	<b>\$196</b>	<b>(\$105)</b>	<b>(\$52)</b>

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)

Case No. PU-07-\_\_\_\_  
 Exhibit \_\_\_\_ (AEH-1)  
 Schedule 5, Page 3 of 4

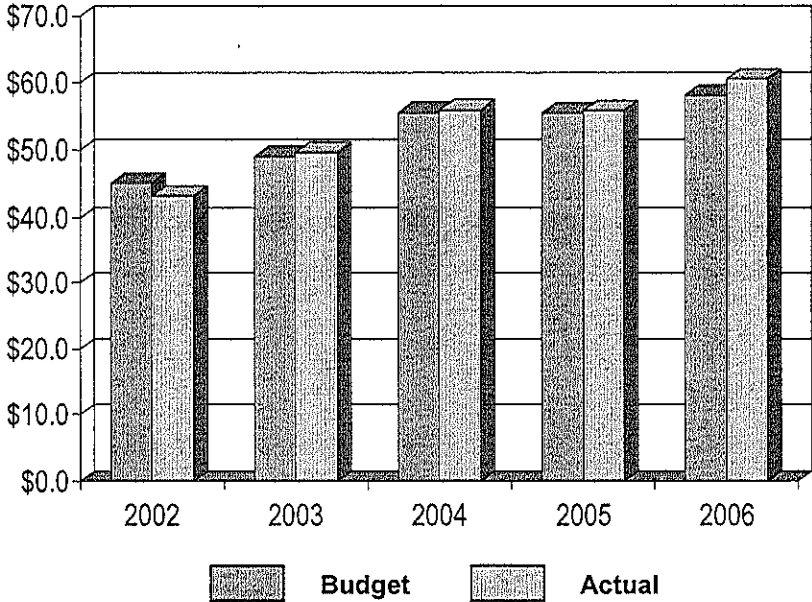
Line No.	Description	Saver Switch 6	Pole Inspection & Replacement Program 7	Cable Replacement Program 8	Rate Case Expense Amortization 9	RDF Amortization 10	Privat Fuel Storage 11
<b>Operating Revenues</b>							
1	Retail						
2	CIP Revenue Adjustment						
3	Interdepartmental						
4	Other Operating						
5	Gross Earnings Tax						
6	<b>Total Operating Revenues</b>	\$0	\$0	\$0	\$0	\$0	\$0
<b>Expenses</b>							
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	<b>Total Operating Expenses</b>	(\$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	<b>Total Taxes</b>	\$15	(\$38)	(\$15)	(\$39)	(\$67)	(\$75)
24	<b>Total Expenses</b>	(\$22)	\$57	\$16	\$61	\$103	\$115
25	Allowance for Funds Used During Construction						
26	<b>Total Operating Income</b>	\$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)

Case No. PU-07-\_\_\_\_  
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 Schedule 5, Page 4 of 4

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) 18
<b>Operating Revenues</b>								
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	<b>Total Operating Revenues</b>	<b>(\$1,800)</b>	<b>(\$318)</b>	<b>(\$39)</b>	<b>(\$221)</b>	<b>(\$532)</b>	<b>\$0</b>	<b>\$186,704</b>
<b>Expenses</b>								
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	<b>Total Operating Expenses</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$148,724</b>
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	<b>Total Taxes</b>	<b>(\$706)</b>	<b>(\$125)</b>	<b>(\$15)</b>	<b>(\$87)</b>	<b>(\$209)</b>	<b>(\$2)</b>	<b>\$9,025</b>
24	<b>Total Expenses</b>	<b>(\$706)</b>	<b>(\$125)</b>	<b>(\$15)</b>	<b>(\$87)</b>	<b>(\$209)</b>	<b>(\$2)</b>	<b>\$176,910</b>
25	Allowance for Funds Used During Construction	\$0		\$0			\$0	\$0
26	<b>Total Operating Income</b>	<b>(\$1,094)</b>	<b>(\$193)</b>	<b>(\$24)</b>	<b>(\$134)</b>	<b>(\$323)</b>	<b>\$2</b>	<b>\$9,794</b>

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

<u>Line</u>	<u>Description</u>	<u>North Dakota Jurisdiction</u>
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%**

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

**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

	<u>Total Company Electric</u>			<u>North Dakota Retail Electric</u>			<u>All Other</u>		
	<u>Beginning Balance</u>	<u>Ending Balance</u>	<u>Average Balance</u>	<u>Beginning Balance</u>	<u>Ending Balance</u>	<u>Average Balance</u>	<u>Beginning Balance</u>	<u>Ending Balance</u>	<u>Average Balance</u>
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	<u>(5,821,431)</u>	<u>(6,216,224)</u>	<u>(6,018,828)</u>	<u>(322,262)</u>	<u>(344,069)</u>	<u>(333,166)</u>	<u>(5,499,169)</u>	<u>(5,872,155)</u>	<u>(5,685,662)</u>
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
<b>11 Total Rate Base</b>	<b>4,436,596</b>	<b>4,996,899</b>	<b>4,716,747</b>	<b>219,107</b>	<b>265,095</b>	<b>242,100</b>	<b>4,217,489</b>	<b>4,731,804</b>	<b>4,474,646</b>

**Income Statement Summary**

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>
<b><u>Operating Revenues</u></b>			
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	<u>0</u>	<u>0</u>	<u>0</u>
6 <b>Total Operating Revenues</b>	<b>3,603,178</b>	<b>186,704</b>	<b>3,416,474</b>
<b><u>Expenses</u></b>			
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	<u>161,492</u>	<u>10,399</u>	<u>151,093</u>
15 <b>Total Operating Expenses</b>	<b>2,560,030</b>	<b>148,264</b>	<b>2,411,766</b>
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	<u>21,401</u>	<u>1,310</u>	<u>20,091</u>
23 <b>Total Taxes</b>	<b>277,274</b>	<b>9,025</b>	<b>268,249</b>
24 <b>Total Expenses</b>	<b>3,230,585</b>	<b>176,910</b>	<b>3,053,675</b>
25 AFUDC	<u>0</u>	<u>0</u>	<u>0</u>
26 <b>Total Operating Income</b>	<b>372,593</b>	<b>9,794</b>	<b>362,799</b>

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-\_\_\_\_  
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 Schedule 8, Page 4 of 6

**Income Tax Summary**

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>
<b><u>Income Before Taxes</u></b>			
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 <b>Total Before Tax Book Income</b>	<b>458,811</b>	<b>10,008</b>	<b>448,803</b>
<b><u>Tax Additions</u></b>			
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 <b>Total Tax Additions</b>	<b>572,080</b>	<b>29,075</b>	<b>543,005</b>
<b><u>Tax Deductions</u></b>			
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 <b>Total Tax Deductions</b>	<b>819,794</b>	<b>38,537</b>	<b>776,474</b>
24 <b>State Taxable Income</b>	<b>211,097</b>	<b>546</b>	<b>210,550</b>
25 State Income Tax Rate	8.99%	6.51%	N/A
26 <b>Total State Income Taxes</b>	<b>18,976</b>	<b>36</b>	<b>18,940</b>
27 <b>Federal Taxable Income</b>	<b>192,121</b>	<b>511</b>	<b>191,610</b>
28 Federal Income Tax Rate	35.00%	35.00%	35.00%
29 <b>Total Federal Income Taxes</b>	<b>67,242</b>	<b>179</b>	<b>67,064</b>
30 <b>Total Federal &amp; State Income Taxes</b>	<b>86,218</b>	<b>214</b>	<b>86,004</b>

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**

	<u>Capital Structure</u>	<u>Rate</u>	<u>Ratio</u>	<u>Weighted Cost</u>	<u>Composite Income Tax Rates</u>	
1	Long Term Debt	6.7900%	45.6100%	3.1000%	State of North Dakota Tax rate	6.50%
2	Short Term Debt	5.7400%	2.6200%	0.1500%	Federal Statutory Tax rate	35.00%
3	Preferred Stock	0.0000%	0.0000%	0.0000%	Federal Effective Tax Rate (1-State Rate * Fed Rate)	32.73%
4	Common Equity	11.5000%	51.7700%	5.9500%	<b>Total North Dakota Composite Tax Rate</b>	<b>39.23%</b>
5	<b>Required Rate of Return</b>			<b>9.2000%</b>	<b>Total Corporate Composite Tax Rate</b>	<b>40.84%</b>

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>
<b><u>Rate of Return (ROR)</u></b>			
6	Total Operating Income	372,593	9,794
7	Total Average Rate Base	<u>4,716,747</u>	<u>242,100</u>
8	<b>ROR (Operating Income / Rate Base)</b>	<b>7.90%</b>	<b>4.05%</b>
<b><u>Return on Equity (ROE)</u></b>			
9	Total Operating Income	372,593	9,794
10	Debt Interest (Rate Base * Weighted Debt Cost)	(153,294)	(7,868)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	<u>0</u>	<u>0</u>
12	Earnings Available for Common	219,299	1,926
13	Equity Rate Base ( Rate Base * Equity Ratio)	<u>2,441,860</u>	<u>125,335</u>
14	<b>ROE (Earnings for Common / Equity Rate Base)</b>	<b>8.98%</b>	<b>1.54%</b>
<b><u>Revenue Deficiency</u></b>			
15	Require Operating Income (Rate Base * Required Return)	433,941	22,273
16	Operating Income	<u>372,593</u>	<u>9,794</u>
17	Operating Income Deficiency	61,348	12,479
18	Revenue Conversion Factor ( 1/(1-Composite Tax Rate) )	<u>1.69041</u>	<u>1.64555</u>
19	<b>Revenue Deficiency (Income Deficiency * Conversion Factor)</b>	<b>103,704</b>	<b>20,535</b>
<b><u>Total Retail Revenue Requirements</u></b>			
20	Retail Related Revenues	2,877,547	147,179
21	Revenue Deficiency	<u>103,704</u>	<u>20,535</u>
22	<b>Total Retail Revenue Requirements</b>	<b>2,981,251</b>	<b>167,714</b>
23	<b><u>Percentage Increase (Decrease)</u></b>	<b>3.60%</b>	<b>13.95%</b>

Rate Base Detail - Cash Working Capital

Expense	Lead Days	Total Company Electric		ND Retail Electric		All Other	
		Dollars	Dollar x Days	Dollars	Dollar x Days	Dollars	Dollar x Days
<b>Fuel Expenses</b>							
1 Coal & Rail Transport	24.78	367,080	9,095,753	21,579	534,739	345,481	8,581,014
2 Gas for Generation	41.90	139,412	5,841,374	8,196	343,414	131,218	5,497,980
3 Oil	14.13	7,092	100,215	417	5,892	8,675	94,324
4 Nuclear & EOL	0.00	80,062	0	4,707	0	75,355	0
5 Nuclear Disposal	78.38	12,473	952,988	721	55,070	11,752	897,618
6		808,100	15,990,030	35,820	938,115	570,480	15,050,915
<b>Purchased Power</b>							
7 Purchases	24.82	989,971	24,373,094	57,980	1,426,977	932,011	22,948,117
8 Interchange	38.21	103,228	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
<b>Labor &amp; Related Costs</b>							
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	2,771,738
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
13 All Other Operating Expenses	42.34	582,448	23,814,050	30,635	1,297,090	531,813	22,516,960
14 Property Tax	353.01	105,494	37,240,437	5,783	2,034,397	99,731	35,206,040
15 Employer's Payroll Taxes	28.83	21,401	574,194	1,310	35,149	20,091	539,045
16 Gross Earnings Tax	55.01	39,086	2,150,121	2,081	114,478	37,005	2,035,845
17 Federal Income Tax	38.50	67,242	2,454,346	179	6,525	67,064	2,447,821
18 State Income Tax	36.50	18,976	692,811	36	1,298	18,940	691,313
19 State Sales Tax Customer Billings	51.88	110,642	5,737,884	0	0	110,642	5,737,884
20 Total Expenses	42.51	2,922,871	124,243,707	157,833	6,521,457	42.57	2,785,238
21 Net Annual Expense Amount			340,394		17,857		322,527
<b>Revenues</b>							
23 Computer Billing	100.00%	45.45	2,879,484	149,550	6,797,048	2,729,934	124,075,500
24 Hand Billed	0.00%	45.45	0	0	0	0	0
25 Retail Revenue Adjustments		45.45	(2,371)	(2,371)	(107,762)	0	0
26 Interdepartmental		0.00	434	0	0	434	0
27 Late Payment		0.00	7,252	245	0	7,007	0
28 Connect and Trouble Charges		45.45	2,217	173	7,863	2,044	92,900
29 CIP Incentive		0.00	0	0	0	0	0
30 Rentals		34.28	4,630	251	8,804	4,379	150,112
31 Interchange Revenues		38.21	388,380	22,648	865,380	385,732	13,974,620
32 Sales for Resale		39.83	255,111	12,380	490,619	242,731	9,619,430
33 Production Associated Revenues		39.83	5,382	375	14,881	8,007	238,057
34 MISO		39.83	38,782	2,125	84,214	34,637	1,372,864
35 Point to Point Firm		39.83	4,680	271	10,740	4,409	174,729
36 Services & Facilities		39.83	8,821	493	19,538	8,128	322,113
37 Ancillary		39.83	6,223	360	14,267	5,883	232,351
38 Distribution Associated Revenues		45.45	1,986	0	0	1,986	90,264
39 Other		45.45	5,367	320	14,544	5,047	229,388
40 JOA - Rev frto PSC		39.83	(1,980)	(118)	(4,597)	(1,864)	(73,870)
41 (blank)		0.00	0	0	0	0	0
42 (blank)		0.00	0	0	0	0	0
43 (blank)		0.00	0	0	0	0	0
44 Total Revenues	44.05	3,803,178	158,713,573	188,704	8,215,318	44.05	3,416,474
46 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			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

<u>Line</u>	<u>Item</u>	<u>Revenue</u> <u>Deficiency (millions)</u>
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 Administrative and General Expense	\$0.063
		<u>\$0.750</u>
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	<u>(\$0.427)</u>
8	Subtotal	\$22.266
9	Less, Gross Margin Growth (Total Revenue Less Cost of Fuel, Purchased Energy and Transmission of Energy by Others)	<u>(\$1.731)</u>
10	Net Revenue Deficiency	\$20.535

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

Case No. PU-07-\_\_\_\_  
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 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)

<u>Line</u>	<u>Functional Class</u>	Increase (Decrease)	<u>Average Annual %</u>
1	Power Production	\$8,694	9.1%
2	Total Transmission	\$2,070	11.7%
3	Transmission of Energy by Others - FERC 565 (1)	<u>(\$1,444)</u>	<u>19.9%</u>
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	<u>\$750</u>	<u>2.6%</u>
9	Total Operating Expenses	\$11,810	7.3%

(1) Included in Gross Margin Growth

Northern States Power Company, a Minnesota Corporation  
Electric Utility - State of North Dakota  
GROSS REVENUE CONVERSION FACTOR

Case No. PU-07-\_\_\_\_\_  
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Definition: The incremental amount of gross revenue required 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	Final	Test Year Ending 12/31/08
		Present Rates (A)	Increase (B)	Final Rates (C) = (B) + (A)
<b><u>Operating Revenues</u></b>				
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	<b>Total Operating Revenues</b>	<b>\$186,704</b>	<b>\$20,535</b>	<b>\$207,239</b>
<b><u>Expenses</u></b>				
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	<b>Total Operating Expenses</b>	<b>\$148,724</b>	<b>\$0</b>	<b>\$148,724</b>
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	<b>Total Taxes</b>	<b>\$9,025</b>	<b>\$8,056</b>	<b>\$17,081</b>
24	<b>Total Expenses</b>	<b>\$176,910</b>	<b>\$8,056</b>	<b>\$184,966</b>
25	AFUDC	\$0	\$0	\$0
26	<b>Total Operating Income</b>	<b>\$9,794</b>	<b>\$12,479</b>	<b>\$22,273</b>

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	Proposed Test Year 2008			Proposed North Dakota Jurisdiction (H) (Col F + G)
		Unadjusted Total Utility (E)	Unadjusted North Dakota Jurisdiction (F)	Adjustments (G)	
<b>Operating Revenues</b>					
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	<b>Total Operating Revenues</b>	<b>\$3,605,727</b>	<b>\$189,614</b>	<b>(\$2,910)</b>	<b>\$186,704</b>
<b>Expenses</b>					
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	<b>Total Operating Expenses</b>	<b>\$2,569,430</b>	<b>\$148,605</b>	<b>\$120</b>	<b>\$148,724</b>
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	<b>Total Taxes</b>	<b>\$285,770</b>	<b>\$10,224</b>	<b>(\$1,199)</b>	<b>\$9,025</b>
24	<b>Total Expenses</b>	<b>\$3,220,959</b>	<b>\$177,980</b>	<b>(\$1,070)</b>	<b>\$176,910</b>
25	Allowance for Funds Used During Constructi	\$0	\$0	0	\$0
26	<b>Total Operating Income</b>	<b>\$384,768</b>	<b>\$11,634</b>	<b>(\$1,840)</b>	<b>\$9,794</b>

<b>Line No.</b>	<b>Description</b>	<b>Allocation Basis</b>
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

Northern States Power Company, a Minnesota Corporation  
 Electric Utility - State of North Dakota  
 Operating Income Jurisdictional Allocation Factors  
 OPERATING INCOME JURISDICTIONAL ALLOCATION FACTORS

Case No. PU-07-\_\_\_\_\_  
 Exhibit\_\_ (AEH-1)  
 Schedule 12, Page 2 of 3

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 transmission 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.

Northern States Power Company, a Minnesota Corporation  
 Electric Utility - State of North Dakota  
 Operating Income Jurisdictional Allocation Factors  
 Calculation of the Two Factor Allocator

Case No. PU-07-\_\_\_\_  
 Exhibit\_\_(AEH-1)  
 Schedule 12, Page 3 of 3

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

O&M Allocator	2006 Actuals	Ratio
O&M excluding A&G		
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%
WHLISL	1.8690%
	100.0000%

ETrans Demand Alloc

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

ECustomerMN/SD/ND

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

2008 Budget A&G Jurisdictional Allocators

ELECTRIC A&G Alloc

2 Factor Allocator	O&M and Plant	MN	ND	SD	WHLISL	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%
<b>Resulting Allocator</b>	<b>100.00%</b>	<b>87.3473%</b>	<b>5.9458%</b>	<b>5.4719%</b>	<b>1.2350%</b>	<b>100.0000%</b>

**Northern States Power Company, a Minnesota Corporation**  
**Electric Utility - State of North Dakota**  
**Rate Base Jurisdictional Allocation Factors**

Case No. PU-07-\_\_\_\_\_  
 Exhibit \_\_\_\_ (AEH-1)  
 Schedule 13, Page 1 of 2

Line No.	Description	Allocation Basis
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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 Production Transmission Other	Demand/Customers/Direct Assigned
4	Common Production Transmission Other	Demand/Customers/Direct Assigned

In addition, the following allocation factors are used to compute North Dakota jurisdictional amounts:

5	TBT Investment	Customers
6	Other Rate Base: Materials & Supplies Non-Plant Assets & Liabilities Prepayments Fuel Inventory	Demand/Customers/Direct Assigned Demand/Customers/Direct Assigned Demand/Customers/Direct Assigned Energy

Northern States Power Company, a Minnesota Corporation  
Electric Utility - State of North Dakota  
Rate Base Jurisdictional Allocation Factors

Case No. PU-07-\_\_\_\_  
Exhibit \_\_\_\_ (AEH-1)  
Schedule 13, Page 2 of 2

Test Year 2008

<u>Line No.</u>	<u>Allocation Factor</u>	<u>Total Utility</u>	<u>North Dakota Jurisdiction</u>	<u>Allocation Factor</u>
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

<u>Line</u> <u>No.</u>	<u>Description</u>	<u>Average Rate Base</u> <u>(A)</u>
	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	<u>\$607,339</u>
	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	<u>\$333,166</u>
	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	<u>\$274,173</u>
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	<u>\$2,706</u>
32	Total Average Rate Base	<u><u>\$242,100</u></u>

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					
Line No.	Description	Total Utility			North Dakota Jurisdiction		
		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