

Rebuttal Testimony and Schedules  
Anne E. Heuer

Before the North Dakota Public Service Commission  
State of North Dakota

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

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

Case No. PU-07-776  
Exhibit 21

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

June 13, 2008

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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 CAPACITY?

8 A. I am the Manager of Revenue Analysis for Xcel Energy Services Inc.

9  
10 Q. HAVE YOU PREVIOUSLY FILED DIRECT TESTIMONY AND SCHEDULES IN THIS  
11 PROCEEDING?

12 A. Yes. I have previously provided Direct Testimony and Schedules on behalf of  
13 Northern States Power Company, a Minnesota corporation (“Xcel Energy” or  
14 the “Company”), operating in North Dakota.

15  
16 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY AND SCHEDULES?

17 A. The purpose of my Rebuttal Testimony and Schedules is to:

- 18 • Respond to several issues raised by Charles W. King and Michael J. Majoros,  
19 Jr. on behalf of the Advocacy Staff (the “Staff”) of the North Dakota Public  
20 Service Commission (the “Commission”), including (Pole Inspection and  
21 Replacement Program, Asset Based and Non-Asset Based Trading Margins,  
22 MISO Schedule 16 and 17 Costs, Nuclear Refueling Outage Costs, Private  
23 Nuclear Fuel Storage, Renewable Development Fund Expenses, Charitable  
24 Contributions, Incentive Compensation, and Income Taxes);
- 25 • Correct an inadvertent error to the allocation of chemical costs used during  
26 the pollution control process at the Allen S. King Generating Plant;



1 A. Mr. Majoros recommends accounting for the costs of these programs in a way  
2 that does not reflect the purposes for which the costs are incurred, in that the  
3 expenses (and capitalized costs) of pole and cable *replacement* (i.e. installation) be  
4 charged to the reserve for *removal*. He did not challenge the reasonableness of  
5 either these programs or the test-year level of costs, but his accounting proposal  
6 would have a significant effect on the revenue requirements associated with these  
7 programs.

8  
9 Q. WHAT IS YOUR UNDERSTANDING OF THE EFFECT OF THAT PROPOSAL?

10 A. Mr. Majoros' proposal would record the costs of investments in new facilities,  
11 such as power line poles and new distribution cable, as depreciation reserve, a  
12 cost category that reflects the costs of eventually removing a facility from service  
13 at the end of its useful life. The net impact on the revenue requirement due to  
14 this accounting change is approximately \$160,000.

15  
16 Q. WHAT IS THE COMPANY'S POSITION REGARDING THIS RECOMMENDATION?

17 A. I believe that Mr. Majoros' recommendation is inconsistent with sound  
18 accounting practices and does not accurately reflect the differences between  
19 removal and replacement of our equipment.

20  
21 Q. WHY IS THIS RECOMMENDATION INCONSISTENT WITH SOUND ACCOUNTING  
22 PRACTICES?

23 A. This recommendation is inconsistent with the Federal Energy Regulatory  
24 Commission ("FERC") Uniform System of Accounts, which prescribe the  
25 recording of investments and expenses in accounts that reflect each cost's nature  
26 and type. Sections of the FERC Uniform System of Accounts read as follows:

27

1           **101 Electric plant in service**

2           A. This account *shall include the original cost* of electric plant, included in  
3           accounts 301 to 399, prescribed herein, owned and used by the utility in  
4           the electric utility operations, and *having an expectation of life in service of more*  
5           *than one year from the date of installation*, including such property owned by  
6           the utility but held by nominees.

7  
8           **108 Accumulated provision for depreciation of electric utility plant**

9           B. *At the time of retirement of depreciable electric utility plant, the account shall be*  
10           *charged with the book cost of the property retired and the cost of removal* and shall  
11           be credited with the salvage value and any other amounts recovered,  
12           such as insurance. ....

13           E. *The utility is restricted in its use of the accumulated provision for depreciation to the*  
14           *purposes set forth above.* (Emphasis added).

15  
16           The costs associated with new poles and cable, such as the costs reflected in our  
17           Pole and Cable Replacement Programs, are for new equipment that will provide  
18           service to our customers over its useful life. As such, the FERC Uniform System  
19           of Accounts would require that such investments be recorded in the appropriate  
20           property account, and depreciated over their expected useful lives, rather than  
21           reflected in the depreciation reserve. Costs appropriate for including in  
22           depreciation reserve are the costs of actually removing a facility from service, not  
23           the costs of the replacement equipment itself.

24  
25           Q. YOU STATED THAT THIS RECOMMENDATION ALSO DOES NOT ACCURATELY  
26           REFLECT THE DIFFERENCES BETWEEN REMOVAL AND REPLACEMENT OF  
27           EQUIPMENT. PLEASE ELABORATE.

28           A. Yes. Accounting treatment always stems from the type of costs incurred. In this  
29           case, *removal* of poles and cable addresses the costs and function of removing the  
30           *current* poles and cables that have been used for prior delivery of energy. Such  
31           costs would be appropriately accounted for in depreciation reserve. The Pole  
32           and Cable Replacement programs, however, address the separate function of

1 actually *replacing* the removed poles and cables with new equipment. Without  
2 replacement, there would be no poles and cable *for future delivery* of energy to  
3 customers.

4  
5 Q. WHAT, THEN, IS YOUR RECOMMENDATION REGARDING MR. MAJOROS'  
6 PROPOSAL REGARDING THE POLE AND CABLE REPLACEMENT PROGRAMS?

7 A. I recommend that the Commission not accept his recommendation and instead  
8 continue to use the accounting as prescribed in the FERC Uniform System of  
9 Accounts to record the costs of these programs. Our proposed adjustments, as  
10 shown in Exhibit \_\_\_\_ (AEH-1) Schedule 5, page 3 of 4, reflect the appropriate  
11 adjustments to account for the addition of costs related to these two programs.

12  
13 **B. Asset Based and Non-Asset Based Trading Margins**

14  
15 Q. PLEASE SUMMARIZE MR. MAJOROS' RECOMMENDATIONS REGARDING  
16 WHOLESALE MARGINS, AS CLARIFIED BY STAFF.

17 A. Mr. Majoros recommends that 100 percent of the margins derived from asset-  
18 based and non asset-based sales be returned to ratepayers through the fuel clause  
19 adjustment mechanism ("FCA").

20  
21 Q. PLEASE COMMENT ON MR. MAJOROS' RECOMMENDATION REGARDING MARGINS  
22 DERIVED FROM ASSET-BASED AND NON ASSET-BASED SALES.

23 A. In his Direct Testimony in this proceeding, Company witness Allen Krug  
24 proposed shareholder retention of 15 percent the margins derived from asset  
25 based sales and 85 percent of the margins from non asset-based sales. He made  
26 these recommendations to more closely align the interests of shareholders and  
27 ratepayers as we participate in the wholesale market. Mr. Krug, in his Rebuttal

1 Testimony, addresses the concerns raised by Mr. Majoros and continues to  
2 support the Company's original position on this issue.

3  
4 Q. ARE ANY ADJUSTMENTS NEEDED TO REFLECT MR. KRUG'S REBUTTAL POSITION?

5 A. No additional adjustments are required to reflect Mr. Krug's Rebuttal position  
6 because the Company's initial proposal had removed these items from base rate  
7 consideration to be used as a reduction to fuel expense through the FCA.

8  
9 Q. MR. MAJOROS INDICATES THAT THE COMPANY'S ADJUSTMENTS TO FCA  
10 REVENUES TO IMPLEMENT THE SHARING OF TRADING MARGINS ARE NOT  
11 NECESSARY. DO YOU AGREE?

12 A. No. Those adjustments are necessary to return the test-year level of trading  
13 margins to customers through the FCA, even if the Commission accepts Mr.  
14 Majoros' position regarding the margins that should be provided to ratepayers.  
15 If these adjustments are not made, margins will be returned twice, once through  
16 the FCA and again as a component of base rates.

17  
18 Q. DO YOU BELIEVE THAT THE COMPANY'S PROPOSAL IS CONSISTENT WITH THE  
19 STAFF'S INTENT TO NOT CONSIDER THESE MARGINS IN SETTING BASE RATES?

20 A. Yes. We sought clarification on the Staff's recommended treatment of trading  
21 margins through discovery, and understand that it is Staff's intent to flow trading  
22 margins back to customers through the FCA, as we proposed. Thus, my  
23 schedules reflect the test-year level of trading margins removed from other  
24 revenues used to reduce the base rate deficiency. This transfer results in a  
25 \$2,378,000 higher base rate revenue deficiency than recommended by Mr.  
26 Majoros.

27

1 **C. MISO Schedule 16 and 17 Costs**

2  
3 Q. WHAT DID MR. MAJOROS RECOMMEND WITH RESPECT TO MISO SCHEDULE 16  
4 AND 17 COSTS?

5 A. Mr. Majoros recommends that these costs not be moved into base rates, as we  
6 proposed. As such, he decreased the base rate revenue requirement by \$532,000.  
7

8 Q. WHAT IS THE COMPANY'S POSITION REGARDING THIS RECOMMENDATION?

9 A. We believe that either base rates or the FCA can provide a reasonable means of  
10 recovering these costs. Thus, the Company accepts Mr. Majoros'  
11 recommendation. To fully reflect the impacts of this recommendation, however,  
12 FCA revenues need to increase by an equivalent amount as the base rate  
13 decrease. Exhibit \_\_\_(AEH-2) Schedule 5, page 2 of 2 reflects this adjustment.  
14

15 Q. HOW DOES THIS CHANGE IN POSITION IMPACT CUSTOMERS?

16 A. Rather than having a fixed amount built into base rates, FCA treatment will  
17 insure that actual costs incurred by the Company will be charged customers.  
18

19 **D. Nuclear Refueling Outage Costs**

20  
21 Q. WHAT DOES MR. MAJOROS RECOMMEND WITH RESPECT TO THE LEVEL OF  
22 NUCLEAR REFUELING OUTAGE EXPENSES TO BE INCLUDED IN THE TEST YEAR?

23 A. Mr. Majoros recommends that the Company's nuclear fuel outage expenses be  
24 reduced from \$2,492,407 to \$811,935. Mr. Majoros characterizes this as the  
25 actual 2008 expense level stemming from the Commission's approval of our  
26 request for accounting treatment of these costs (in its Order Changing  
27 Accounting Treatment in Case No. PU-07-774), but it is really the first year,

1 *partial* amortization level, which does not reflect either the direct costs or the  
2 amortized costs of all three nuclear units.

3  
4 Q. DO YOU AGREE WITH HIS RECOMMENDATION?

5 A. No. I do not agree with this recommendation because I do not believe that the  
6 \$811,935 first-year amortization expense under the newly approved accounting  
7 method for these costs offers a representative cost level, which should be used  
8 for the purpose of setting rates. Actual “direct” costs incurred in the test year  
9 are budgeted to be approximately \$2.5 million (for the North Dakota  
10 jurisdiction), while we project the ongoing annual amortization cost level will  
11 reach approximately \$2.3 million (when all three nuclear units undergo outages  
12 whose costs are recorded under the new method). Since one of the objectives  
13 of setting rates based on a test year is to establish a reasonable and normal cost  
14 level for reflection in rates, using only the first-year of the amortization of  
15 \$811,935 would significantly understate the true representative annual level of  
16 these outage costs because this amortization level does not reflect the costs of all  
17 three nuclear units.

18  
19 Q. PLEASE GIVE SOME BACKGROUND ON THE HISTORY OF THE COMPANY’S  
20 REQUEST TO CHANGE ACCOUNTING.

21 A. On December 7, 2007, the Company petitioned the Commission for  
22 authorization to change the accounting method for costs associated with routine  
23 nuclear refueling outages from the direct expense method to the deferral-and-  
24 amortization method in Case No. PU-07-774. On February 13, 2008, the  
25 Commission approved the Company’s change of accounting request in its Order  
26 Changing Accounting Treatment.

27

1 Q. DID THE COMMISSION'S ORDER CHANGING ACCOUNTING TREATMENT REQUIRE  
2 THE USE OF THE FIRST-YEAR AMORTIZATION COST LEVEL IN THIS CASE?

3 A. No. That Order specified that the issue of the appropriate cost level to be used  
4 in this rate case would be determined in this proceeding, and was not addressed  
5 by the decision to approve the accounting method change.

6  
7 Q. WHY DOES THE COMPANY BELIEVE THIS CHANGE OF ACCOUNTING WAS  
8 APPROPRIATE?

9 A. We believe that the deferral-and-amortization method of accounting for nuclear  
10 refueling costs is superior to the direct-expense method and should be adopted  
11 for use in ratemaking in North Dakota and offers benefits for all stakeholders.  
12 Key reasons in support of the deferral-and-amortization method include:

13

- 14 • It levels the costs over time, facilitating the appropriate reflection of  
15 normalized cost levels;
- 16 • It appropriately spreads the costs over the period that customers receive  
17 the benefits of the expenses; and
- 18 • It better matches revenues with expenses.

19

20 As discussed in detail in our petition in Case No. PU-07-774, the direct-expense  
21 method formerly used to account for nuclear refueling outage costs reflects the  
22 costs as expense on the Company's books and records in the month incurred.  
23 Generally speaking, it is unusual to have periodic costs of this magnitude (over  
24 \$20 million) incurred in a single month. In addition, further exacerbating this  
25 situation, the number of refueling outages occurring in a year fluctuates. By  
26 contrast, the deferral-and-amortization method will smooth these swings by

1 spreading costs over the period in which the benefit occurs (the period between  
2 refueling outages for each unit).

3  
4 Q. DOES THE COMPANY HAVE AN ALTERNATIVE RECOMMENDATION?

5 A. Yes. The Company recommends that a normal amortized expense level be used,  
6 which reflects the future annual level of refueling outage costs for all three  
7 nuclear units, as they would be treated under the deferral-and-amortization  
8 method. The result is an annual amortized expense of \$2,319,262 (included in  
9 the Company's Nuclear Refueling Outage Accounting Petition), which is  
10 \$173,145 less than the test year expense of \$2,492,407.

11  
12 Q. WHY IS THIS THE APPROPRIATE LEVEL TO INCLUDE IN THE TEST YEAR?

13 A. We believe the proposed amortization level of \$2,319,262<sup>1</sup>, is the appropriate  
14 level to be used for setting future rates in this case because it reflects the normal,  
15 annualized level of our amortization expenses. In setting test year expense levels,  
16 it is important to set costs consistent with the future time period final rates will  
17 be in effect.

18  
19 Q. WOULD THE FIRST YEAR AMORTIZATION LEVEL MEET THIS STANDARD?

20 A. No. As discussed in detail in our petition in Case No. PU-07-774, the first year  
21 \$811,935 amortization level would not reflect the ongoing amortization expense  
22 levels, but rather the amortization amount at its lowest, start-up level, which does  
23 not include costs for all three nuclear units. With the change of accounting, the  
24 first year's amortization expense (2008) reflects only a partial year (9 months)  
25 level for the amortization associated with Prairie Island Unit 1, a partial year (3

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<sup>1</sup> Please see the Company's December 5, 2007 petition in Docket No. PU-07-774, page 11, line 1. Supporting calculations can be found in the Company's petition seeking Trade Secret Protection dated December 5, 2007, Schedule E, *Amortization of Reload O&M Costs*.

1 months) level for the amortization associated with Prairie Island Unit 2, and no  
2 amortization expense for the Monticello plant.

3  
4 Q. HOW DOES THIS COMPARE TO NORMAL LEVELS OF EXPENSES?

5 A. As rates are set for 2009 and beyond, all three nuclear units will be recording  
6 amortization expenses on a much more stable basis, which is the intended  
7 purpose for adopting the amortization accounting method. As such, it is  
8 appropriate to set rates based on a level which includes a normal amount for all  
9 three units, rather than a level that only includes a partial, first year amortization  
10 level.

11  
12 Q. WHAT IS THE EFFECT ON THE COMPANY'S REVENUE REQUIREMENT?

13 A. The Company is proposing to reduce our filed revenue requirement by \$173,145  
14 to reflect the annualized amortization expense referenced above.

15  
16 Q. ARE THERE OTHER REASONABLE APPROACHES TO DETERMINING A NORMAL AND  
17 REPRESENTATIVE LEVEL OF AMORTIZED COSTS FOR NUCLEAR FUEL OUTAGES?

18 A. Yes. There are other ways to develop a level of normal amortized costs for  
19 nuclear fuel outages that would be reasonable and representative of ongoing cost  
20 levels. The Company is open to further refinement and discussion of those  
21 costs.

22  
23 **E. Private Nuclear Fuel Storage**

24  
25 Q. WHAT DOES MR. MAJOROS RECOMMEND WITH RESPECT TO PRIVATE NUCLEAR  
26 FUEL STORAGE EXPENSES?

1 A. Mr. Majoros recommends that the Company's private nuclear fuel outage  
2 expenses be reduced by \$190,000 because "the [Commission] has not approved  
3 the project"<sup>2</sup> and because of his understanding that "the project is stalled."<sup>3</sup>  
4

5 Q. DOES HE OFFER ANY EVIDENCE THAT THE COSTS WERE INACCURATELY  
6 DETERMINED OR IMPRUDENTLY INCURRED?

7 A. No.  
8

9 Q. DO YOU AGREE WITH HIS RECOMMENDATION?

10 A. No. Whether the project is stalled or not has no bearing on whether the costs  
11 are legitimate and prudently incurred. The operation of nuclear generating  
12 facilities provides substantial cost advantages to customers, including customers  
13 in North Dakota. Operating nuclear generating facilities leads to costs, including  
14 the costs of long-term storage of spent nuclear fuel.  
15

16 Q. WERE THE COMPANY'S EFFORTS TO IMPLEMENT PRIVATE NUCLEAR FUEL  
17 STORAGE APPROPRIATE?

18 A. Yes. The Company's efforts to take initiative to find a solution to that problem  
19 were appropriate. As Mr. Charles Bomberger explained in his Direct Testimony,  
20 temporary storage of spent fuel on site at Prairie Island was limited, and the  
21 Company implemented a strategy to pursue permanent storage. The Company  
22 took a proactive approach to preserve the advantages provided by low cost  
23 nuclear generation. While those efforts have not been completed, there is no  
24 basis to conclude that any inappropriate or imprudent costs have been incurred  
25 by the Company to resolve this extremely complex and important issue. As a

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<sup>2</sup> Majoros Direct Testimony at 23.

<sup>3</sup> Id.

1 result, the recovery of those costs should not rest on having obtained advance  
2 approval to incur those costs, particularly when such a requirement would be  
3 imposed on an “after the fact” basis.

4  
5 **F. Renewable Development Fund Expenses**

6  
7 Q. WHAT DOES MR. MAJOROS RECOMMEND WITH RESPECT TO RENEWABLE  
8 DEVELOPMENT FUND EXPENSES?

9 A. Mr. Majoros recommends that the Company’s Renewable Development Fund  
10 (“RDF”) expenses in the amount of \$265,000 be disallowed because: “The RDF  
11 is a Minnesota program and expenditure. It should not be charged to North  
12 Dakota customers.”<sup>4</sup>

13  
14 Q. DO YOU AGREE WITH HIS RECOMMENDATION?

15 A. No. In order to continue to operate the Prairie Island Nuclear Generating  
16 Facility, which required on-site interim nuclear fuel storage, the Company was  
17 required to provide funding of an RDF. The total annual funding of the RDF in  
18 relation to casks located at our Prairie Island Nuclear Plant is \$16 million. The  
19 operation of the nuclear plants provides substantial cost savings to all of our  
20 customers, including customers in North Dakota, but saving substantial costs  
21 may also require the Company to incur some costs, in this case the RDF.  
22 Legislation passed in 2007 will also require the Company to provide funding of  
23 \$350,000 per cask located at our Monticello Nuclear Plant<sup>5</sup>. We expect to be  
24 required to fund \$3.5 million related to Monticello casks in 2008.

25  

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<sup>4</sup> Majoros Direct Testimony at 23.

<sup>5</sup> The RDF funding requirements are included in Minn. Stat. 116C.779, subd.1, (b).

- 1 Q. WHAT WOULD BE THE EFFECT IF THE COMPANY REFUSED TO PROVIDE THE  
2 RDF?
- 3 A. If the Company refused to provide that funding, the operation of the nuclear  
4 generating facilities would be impossible, and the Company would be required to  
5 replace approximately 1,670 MW of capacity, of which the North Dakota share is  
6 82 MW. It seems obvious that the difference between the ongoing costs of  
7 nuclear generation and the replacement costs would greatly exceed the \$265,000  
8 of RDF costs.  
9
- 10 Q. DOES THE REVENUE REQUIREMENT INCLUDE ALL RDF EXPENSES?
- 11 A. No. The test year includes \$265,000 in RDF expenses, representing the North  
12 Dakota allocated share of the energy production (“EP”) grant payments and a  
13 portion of the RDF administrative costs (prorated based on target funding for  
14 energy production grants versus research and development (“R&D”) grants in  
15 the 3<sup>rd</sup> RDF Funding Cycle Request for Proposal). The test year does not  
16 include expenditures related to R&D and Renewable Energy Production  
17 Incentives, which are born directly by Minnesota electric retail customers.  
18
- 19 Q. HAVE FUNDED PARTICIPANTS IN THE RDF BEEN RESTRICTED TO MINNESOTA  
20 ENTITIES?
- 21 A. No. In fact, nine grants from the RDF have been awarded to North Dakota  
22 based projects out of 70 grants awarded. These nine projects consist on eight  
23 R&D grants totaling \$6.7 million and one EP grant award of \$2 million, which  
24 the prospective recipient has since chosen to decline. North Dakota based R&D  
25 grants comprise approximately 20 percent of the total R&D grants awarded.  
26 Please note, as I stated earlier, that R&D project expenditures are born entirely  
27 by Minnesota electric customers, even though the State of North Dakota derives

1 the economic benefit of these projects. Please see Exhibit\_\_\_ (AEH-2) Schedule  
2 1 for additional detail on grant awards to North Dakota based projects.

3  
4 **G. Charitable Contributions**

5  
6 Q. WHAT DID MR. MAJOROS RECOMMEND WITH RESPECT TO CHARITABLE  
7 CONTRIBUTIONS?

8 A. Mr. Majoros recommended that the Company's proposal be rejected, suggesting  
9 that the Commission's allowance of recovery of a portion of these contributions  
10 "may have slipped through in previous gas cases."<sup>6</sup>

11  
12 Q. WHAT IS THE COMPANY'S POSITION REGARDING THIS RECOMMENDATION?

13 A. The Company continues to recommend allowing recovery of a portion of these  
14 costs as a sound approach that the Commission should apply in this case.

15  
16 Q. WHAT IS THE AMOUNT OF RECOVERY THAT THE COMPANY IS SEEKING IN THIS  
17 CASE?

18 A. The Company is seeking recovery of \$86,000 in charitable contributions in our  
19 2008 test year. This amount is 50 percent of the total amount the Company  
20 contributes to charities and institutions associated with the electric service  
21 territory in the North Dakota jurisdiction.

22  
23 Q. WHO HAVE RECEIVED FUNDING BY THE COMPANY?

24 A. As stated above, Xcel Energy contributes to various charities and institutions  
25 associated with the electric service territory in the North Dakota jurisdiction. I  
26 have included as Exhibit\_\_\_(AEH-2) Schedule 2 the list of organizations to  

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<sup>6</sup> Majoros Direct Testimony at 22-23

1 which the Company contributed during 2006, the basis for our 2008 test year  
2 adjustment.

3  
4 **H. Incentive Compensation**

5  
6 Q. WHAT DID MR. MAJOROS RECOMMEND REGARDING INCENTIVE COMPENSATION?

7 A. He recommended that the Company's incentive compensation adjustment be  
8 reduced "to reflect the 15 percent of base pay limit established in NSP's last  
9 Minnesota Order."<sup>7</sup>

10  
11 Q. DO YOU AGREE WITH HIS RECOMMENDATION?

12 A. No. In the Company's last general electric rate case in Minnesota, the Minnesota  
13 Public Utilities Commission ("MPUC") adopted a limit based on 25 percent of  
14 base pay,<sup>8</sup> not the 15 percent assumed by Mr. Majoros. The Company has  
15 proposed the same 25 percent limit be applied in this proceeding as was adopted  
16 by the MPUC. A limit based on 25 percent of base pay is appropriate for all of  
17 the reasons explained by Mr. Marvin McDaniel in his Direct Testimony. This is  
18 also consistent with the treatment accepted in the NDPSC settlement agreement  
19 in the Company's most recent North Dakota Gas Case No. PU-06-525.

20  
21 Q. IS MR. MAJOROS' COMPUTATION OF THE EFFECT OF CHANGING FROM A 25  
22 PERCENT LIMIT TO A 15 PERCENT LIMIT CORRECT?

23 A. No. Based on our calculations, if the Company were to adjust the case to limit  
24 incentive compensation recovery to 15 percent of base pay, an additional

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<sup>7</sup> Majoros Direct Testimony at 24.

<sup>8</sup> Docket No. E002/GR-05-1428 Order Dated September 1, 2006 at page 18 states in part "The Commission concurs with, accepts and adopts the ALJ's recommendation on this issue, which was to cap individual incentive payments at 25% of an employee's base salary...".

1 expense reduction of \$34,000 would be necessary, not the additional reduction of  
2 \$142,000 suggested by Mr. Majoros. I have included the calculation used to  
3 derive the \$34,000 reduction as Exhibit\_\_\_(AEH-2) Schedule 3.  
4

5 **I. Income Taxes**  
6

7 Q. DID MR. MAJOROS RECOMMEND ANY ADJUSTMENT TO THE METHOD USED BY  
8 THE COMPANY TO CALCULATE ITS INCOME TAX EXPENSE?

9 A. No. Mr. Majoros did not recommend any adjustment to the method used by the  
10 Company to calculate its income tax expense, but he did recommend that the  
11 Commission “consider placing NSP on alert” that the Commission may consider  
12 “the consolidated tax issue in the next rate case.”<sup>9</sup>  
13

14 Q. WHAT IS THE COMPANY’S RECOMMENDATION?

15 A. Mr. Majoros has provided no basis for the Commission to consider any change  
16 in its long-standing practice of using the stand-alone method to determine  
17 income taxes, which is part of the fundamental regulatory policy of maintaining  
18 separation of regulated and unregulated expenses. Thus, there is no basis to  
19 increase the number of issues and complexity of a future rate case.  
20

21 **J. Allen S. King Chemical Cost Adjustment**  
22

23 Q. WHAT ADJUSTMENT ARE YOU PROPOSING RELATED TO THE ALLEN S. KING  
24 CHEMICAL COSTS?

25 A. In the process of reviewing our original submission, it was discovered that the  
26 allocation of Allen S. King chemical costs to our North Dakota jurisdiction

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<sup>9</sup> Majoros Direct Testimony at 8

1 inadvertently included an amount that should have been assigned to the  
2 Minnesota jurisdiction. I have made an adjustment that reduces North Dakota  
3 expense by \$321,594 to reflect the reallocation of these costs. My calculation is  
4 set forth on Exhibit (AEH-2)\_\_\_Schedule 9.

### 6 III. QUANTIFICATION OF STAFF POSITION

#### 8 A. Refuse Derived Fuel Generation

10 Q. WHAT DOES MR. KING RECOMMEND WITH RESPECT TO REFUSE DERIVED FUEL  
11 EXPENSES?

12 A. Mr. King recommends that the Company's investment in refuse-derived energy  
13 is responsive to Minnesota mandates, should be charged to Minnesota ratepayers  
14 and, therefore, should be disallowed.

16 Q. WHAT IS THE COMPANY'S POSITION WITH REGARDS TO HIS RECOMMENDATION?

17 A. The Company opposes Mr. King's recommendations for the reasons explained  
18 by Ms. Engelking.

20 Q. IF THE COMMISSION ADOPTED MR. KING'S RECOMMENDATION, IS MR.  
21 MAJOROS' CALCULATION OF THE EFFECTS OF THAT RECOMMENDATION  
22 CORRECT?

23 A. No. Although the source of Mr. Majoros' calculation is the Company's response  
24 to Information Request No. 3-4 in which we quantify the revenue requirements  
25 for the refuse-derived (garbage) fuel resources that are included in the 2008 test  
26 year, this calculation does not include the cost of either replacement energy or  
27 capacity lost because this generation source would not be available to meet

1 customer demand for electricity. Even if the Commission accepted Mr. King's  
2 recommendation, the revenue requirement should include the cost of  
3 replacement energy and lost capacity.

4  
5 **B. Depreciation**

6  
7 Q. WHAT DOES MR. KING RECOMMEND WITH RESPECT TO DEPRECIATION  
8 EXPENSES?

9 A. Mr. King recommends that the North Dakota depreciation expense be reduced  
10 from \$19,345,000 to \$15,292,000 or by \$4,053,000. Mr. King's schedules,  
11 however, calculate a new North Dakota accrual of \$15,230,000 or a reduction of  
12 \$4,115,000.

13  
14 Q. WHAT IS THE COMPANY'S POSITION WITH REGARDS TO HIS RECOMMENDATION?

15 A. The Company opposes Mr. King's recommendation for the reasons explained by  
16 Mr. Jeffrey Robinson.

17  
18 Q. IF THE COMMISSION ADOPTED MR. KING'S RECOMMENDATION, IS MR.  
19 MAJOROS' CALCULATION OF THE EFFECTS OF THAT RECOMMENDATION  
20 CORRECT?

21 A. No. Mr. Majoros' calculation does not consider the deferred income tax effect  
22 of a reduction in book depreciation as well as the effect of accumulated deferred  
23 income taxes associated with a reduction in the accumulated reserve for  
24 depreciation.

25  
26 Q. HAVE YOU MADE A CALCULATION THAT CORRECTS SOME OF THESE OMISSIONS?

1 A. Yes. Mr. Majoros adjusts the average accumulated reserve for depreciation by  
2 \$2,058,000 (\$4,115,000 divided by 2), but does not recognize the resulting  
3 increase in the average accumulated deferred income taxes of \$807,000  
4 (\$1,614,000 divided by 2). The net result is an overall decrease in rate base of  
5 \$1,251,000 rather than the \$2,058,000 suggested by Mr. Majoros. With respect to  
6 the income statement, Mr. Majoros' adjustments show a decrease in depreciation  
7 expense of \$4,115,000 and an increase in Federal and State income tax of  
8 \$1,614,000, resulting in a decrease in total expense of \$2,501,000. My  
9 calculation shows that rather than there being an increase in State and Federal  
10 income tax expense, there is actually an increase in deferred income tax expense  
11 of \$1,614,000 resulting when depreciation expense is decreased by \$4,115,000,  
12 and a decrease in State and Federal income tax expense of \$16,000 resulting from  
13 the decrease in rate base. This change results in a Total Expense decrease of  
14 \$2,517,000, rather than the decrease of \$2,501,000 suggested by Mr. Majoros.

15

16 **C. Allen S. King Generating Plant**

17

18 Q. WHAT DOES MR. KING RECOMMEND WITH RESPECT TO THE ALLEN S. KING  
19 GENERATING FACILITY?

20 A. Mr. King recommends that the costs of the rehabilitation be deducted from the  
21 Company's revenue requirement.

22

23 Q. WHAT IS THE COMPANY'S POSITION WITH REGARDS TO HIS RECOMMENDATION?

24 A. The Company opposes Mr. King's recommendation for the reasons explained by  
25 Ms. Engelking.

26

1 Q. IF THE COMMISSION ADOPTED MR. KING'S RECOMMENDATION, IS MR. KING'S  
2 CALCULATION OF THE EFFECTS OF THAT RECOMMENDATION CORRECT?

3 A. No. There are a number of computational and numerical corrections needed in  
4 Mr. King's calculation, including:

- 5 • Estimating the amount of plant investment the Company has included in its  
6 2008 test year based on the Company's May 3, 2002 estimate for this project  
7 escalated to 2008 using the Handy-Whitman Index (\$674 million), rather than  
8 using the amount directly included in the test year (\$477 million);
- 9 • Estimating the amount of net plant investment for this single project included  
10 in the test year based on a reserve ratio. It is inappropriate to apply a reserve  
11 ratio for the entire plant to the new plant investment as suggested by Mr.  
12 King, assuming that the entire plant will include accumulated depreciation not  
13 related to the new investment. In addition, Mr. King's reserve ratio is  
14 calculated from information related to the Allen S. King Plant included in the  
15 Company's response to NDPSC IR 2-144 and shown on Exhibit\_\_\_(CWK-  
16 7) Schedule 2, page 1 of 1. Derivation of this ratio was based on two  
17 numerical transpositions from this schedule, specifically, plant in service  
18 (column c) and the reserve balance (column e) for the Allen S. King Plant;
- 19 • Not considering accumulated deferred income taxes in the calculation of rate  
20 base or recognizing deferred tax expense and State and Federal income tax  
21 expense as separate items on the income statement;
- 22 • Estimating the amount of depreciation expense included in the test year  
23 based on the estimated plant investment described above; and
- 24 • Using the North Dakota jurisdictional demand allocator excluding the impact  
25 of the Interchange Agreement billings to NSP-Wisconsin. Mr. King should  
26 have used a composite demand allocator of 4.88 percent rather than the 5.34  
27 percent he used in the calculation of his adjustment.

1 Q. HAVE YOU MADE A CALCULATION THAT CORRECTS FOR THE ISSUES RAISED  
2 ABOVE?

3 A. Yes. My calculation, as shown on Exhibit\_\_\_(AEH-2), Schedule 4, page 1 of 2,  
4 shows that the revenue requirement included in the test year associated with the  
5 rehabilitation of the Allen S. King Plant is \$3,363,000.  
6

7 **D. High Bridge Generating Plant**  
8

9 Q. WHAT DOES MR. KING RECOMMEND WITH RESPECT TO THE HIGH BRIDGE  
10 GENERATING FACILITY?

11 A. Mr. King recommends that, “Since the plant is apparently needed, its costs  
12 should be allowed, but at the level suggested in the alternative plan set forth in  
13 Exhibit\_\_\_(CWK-2).”<sup>10</sup>  
14

15 Q. WHAT IS THE COMPANY’S POSITION WITH REGARDS TO HIS RECOMMENDATION?

16 A. The Company opposes Mr. King’s recommendations for the reasons explained  
17 by Ms. Engelking.  
18

19 Q. IF THE COMMISSION ADOPTED MR. KING’S RECOMMENDATION, IS MR. KING’S  
20 CALCULATION OF THE EFFECTS OF THAT RECOMMENDATION CORRECT?

21 A. No. There are a number of issues with the approach Mr. King took in his  
22 calculations, including:

- 23 • Estimating the capital cost included in the 2008 test year for the High Bridge  
24 Plant by escalating the capital cost included in the MERP Proposal (\$515  
25 million--\$394 multiplied by the escalator 1.3085 calculated using the Handy-

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<sup>10</sup> King Direct Testimony at 8.

- 1 Whitman Index) rather than using the actual test year amount (\$369.5  
2 million);
- 3 • Making an error in copying the capital cost of the High Bridge Alternative  
4 Plan (\$71 million rather than the \$77 million Mr. King includes in  
5 Exhibit\_\_\_(CWK-4));
  - 6 • Failing to recognize that the amount of plant in service included in the test  
7 year as the average of beginning of year and end of year, not the ending  
8 balance;
  - 9 • Not considering a reduction in plant in service by the average reserve for  
10 depreciation balance as well as accumulated deferred income taxes;
  - 11 • Using the North Dakota jurisdictional demand allocator unadjusted for  
12 billings to NSP-Wisconsin through the Interchange Agreement (5.34 percent)  
13 versus adjusting the demand allocator to consider the effect of Interchange  
14 Agreement billings to NSP-Wisconsin (4.88 percent);
  - 15 • Using a full year of depreciation expense rather than recognizing only 7 and  
16 one half months of expense based on the May 2008 High Bridge in-service  
17 date;
  - 18 • Not recognizing deferred tax expense as well as State and Federal Income  
19 Taxes in the determination of Total Operating Income; and
  - 20 • Not recognizing the cost of replacement energy and capacity lost because the  
21 Alternate Proposal did not included the increase in capacity and energy  
22 included in the selected MERP proposal.

23  
24 Q. HAVE YOU MADE A CALCULATION THAT CORRECTS SOME OF THE ISSUES STATED  
25 ABOVE?

1 A. Yes. My calculation, as shown on Exhibit\_\_\_(AEH-2), Schedule 4, page 2 of 2  
2 shows that, using Mr. King’s assumptions, the difference between the selected  
3 High Bridge proposal and an estimate of the alternate proposal is \$1,102,000.  
4

5 **E. Grand Meadow Wind Farm and Wind-Related Transmission**  
6

7 Q. WHAT DOES MR. KING RECOMMEND WITH RESPECT TO THE GRAND MEADOW  
8 WIND FACILITY AND WIND-RELATED TRANSMISSION FACILITIES?

9 A. Mr. King states that he is “told that capacity factors and the resulting cost of  
10 energy on a kWh basis in North Dakota is about 25 percent lower than those of  
11 Minnesota wind farms.”<sup>11</sup> Therefore, he recommends that 25 percent of the  
12 revenue requirements for the Grand Meadow Wind Farm as well as wind-related  
13 transmission investments included in the 2008 test year be disallowed.  
14

15 Q. WHAT IS THE COMPANY’S POSITION WITH REGARDS TO HIS RECOMMENDATION?

16 A. The Company opposes Mr. King’s recommendation for the reasons explained by  
17 Ms. Engelking.  
18

19 Q. IF THE COMMISSION ADOPTED MR. KING’S RECOMMENDATION, IS MR. KING’S  
20 CALCULATION OF THE EFFECTS OF THAT RECOMMENDATION CORRECT?

21 A. No. Although the source of Mr. King’s calculation is the Company’s response to  
22 Information Request No. 3-4 in which we quantify the revenue requirements for  
23 the Grand Meadow Wind Farm and wind-related transmission investments  
24 included in the 2008 test year, this calculation does not include the cost of  
25 replacement energy lost because the Grand Meadow Wind Farm is adjusted to  
26 generate 25 percent less energy to meet customer energy requirements.

---

<sup>11</sup> King Direct Testimony at 13.

1 **F. Minnesota Mercury Emission Reduction Act Costs**

2

3 Q. WHAT DOES MR. KING RECOMMEND WITH RESPECT TO THE MINNESOTA  
4 MERCURY EMISSION REDUCTION ACT (“MMRA”) COSTS?

5 A. Mr. King recommends that the costs of compliance with the MMRA be  
6 deducted from the Company’s revenue requirement.

7

8 Q. WHAT IS THE COMPANY’S POSITION WITH REGARDS TO HIS RECOMMENDATION?

9 A. The Company opposes Mr. King’s recommendation for the reasons explained by  
10 Ms. Engelking.

11

12 Q. IF THE COMMISSION ADOPTED MR. KING’S RECOMMENDATION, IS MR. KING’S  
13 CALCULATION OF THE EFFECTS OF THAT RECOMMENDATION CORRECT?

14 A. Yes. The source of Mr. King’s calculation is the Company’s response to  
15 Information Request No. 3-4 in which we quantify the revenue requirements for  
16 compliance with the MMRA included in the 2008 test year

17

18 **G. Effect on Return on Equity (“ROE”)**

19

20 Q. HAVE YOU ESTIMATED THE CUMULATIVE EFFECT OF THE RECOMMENDATIONS  
21 OF MR. KING AND MR. MAJOROS ON THE COMPANY’S ROE IN NORTH  
22 DAKOTA?

23 A. Yes, Exhibit\_\_\_\_(AEH-2), Schedule 8, reflects the recalculation of the vast  
24 majority of these changes. While time has not allowed me to make a precise  
25 calculation of the cumulative effect of the recommendations made by Mr. King  
26 and Mr. Majoros, my estimate is that these calculations will lead to a reduction of  
27 approximately \$13.3 million in the Company’s proposed revenue requirement.

1 That reduction in revenue will reduce the Company's earnings by approximately  
2 \$8.1 million. The effect of an \$8.1 million reduction in earnings is to reduce the  
3 effective ROE from the 10.75 percent that has been stipulated by the Staff and  
4 the Company to 4.33 percent, a level that is clearly detrimental to the continued  
5 health of the Company's utility operations in North Dakota. Mr. Kent Larson  
6 will further discuss this issue.

7  
8 Q. HAVE YOU ESTIMATED THE ONGOING EFFECT OF THE RECOMMENDATIONS BY  
9 MR. KING AND MR. MAJOROS REGARDING COMPANY INVESTMENTS?

10 A. Yes. In addition to an immediate impact in this case, the disallowances of major  
11 investments recommended by Mr. King and Mr. Majoros related to the  
12 Company's Allen S. King and High Bridge generating plants could be expected  
13 to have ongoing impacts over the lives of the disallowed investments, unless  
14 reversed by the Commission in a future case. Absent such a reversal, I have  
15 estimated that the ongoing effect would be to reduce effective earnings from the  
16 Company's North Dakota electric business by approximately \$3 million each year  
17 over the next 30 years, which is equivalent to an over 22 percent reduction in the  
18 required return to shareholders. Such an ongoing reduction of earnings would  
19 compound the detrimental effect on the financial health and viability of the  
20 Company's North Dakota electric utility operations. Mr. Kent Larson will  
21 further discuss this issue.

22  
23 **H. Cumulative Effect of Company's Adjustments**

24  
25 Q. WHAT IS THE CUMULATIVE EFFECT OF THE ADJUSTMENTS AGREED TO BY THE  
26 COMPANY?

1 A. The cumulative effect of the adjustments agreed to are included on  
2 Exhibit\_\_\_(AEH-2), Schedule 6. Based on these adjustments the Company's  
3 proposed revenue deficiency is \$17,946,000. This is supported by a revised cost  
4 of service provided in Exhibit\_\_\_(AEH-2), Schedule 7. A bridge schedule  
5 reflecting the various proposed Rebuttal adjustments has also been included as  
6 Exhibit\_\_\_(AEH-2), Schedule 5.

7

8 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

9 A. Yes it does.

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STATE OF NORTH DAKOTA  
BEFORE THE  
PUBLIC SERVICE COMMISSION

In the Matter of the Application of Northern )  
States Power Company, a Minnesota Corporation )  
For Authority to Increase Rates for Electric Service )  
in North Dakota )

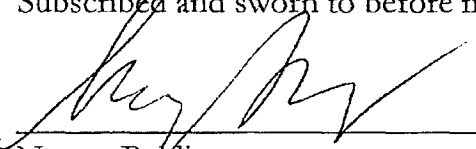
Case No. PU-07-776

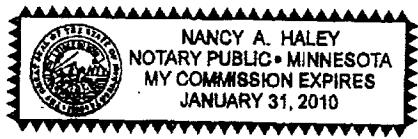
**AFFIDAVIT OF  
Anne E. Heuer**

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

  
\_\_\_\_\_  
Anne E. Heuer

Subscribed and sworn to before me, this 13 day of June, 2008.

  
\_\_\_\_\_  
Notary Public



## Use of RDF Funding in North Dakota

### Energy Production Projects (EP)

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

### Research/Development Projects (RD)

Cycle	Total Projects	North Dakota Projects	% ND Projects	Total Awarded	North Dakota Awards	% ND RD Awards
1	11	3	27%	\$6,247,566	\$1,754,620	28%
2	18	1	6%	\$12,804,466	\$999,995	8%
3	17	4	24%	\$14,397,817	\$3,969,277	28%
<b>Total RD</b>	<b>46</b>	<b>8</b>	<b>17%</b>	<b>\$33,449,849</b>	<b>\$6,723,892</b>	<b>20%</b>
<b>Grand Total</b>	<b>70</b>	<b>9</b>	<b>13%</b>	<b>\$74,866,987</b>	<b>\$8,723,892</b>	<b>12%</b>

### Project Detail

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

(\*) Includes \$10 M Awarded to Excelsior Energy by the MPUC

(\*\*) American Crystal Sugar Company was awarded \$2 M. Since the award, ACSC has chosen to decline the RDF grant to pursue other uses of the planned methane production at the plant.

(\*\*\*) Project includes two Fargo based engineering consultants for American Crystal Sugar Corporation, Moorhead, MN, which is the project host for the demonstration.

(\*\*\*\*) Project includes 6 months of testing at Federal Machine, West Fargo, ND.

## RDF AWARDS

### North Dakota Project Descriptions

#### Cycle 1

***Research/Development Projects:***

**University of North Dakota**, Grand Forks, ND, Impacts of Biomass Cofiring on the Operation of a Next-Generation Power System, \$444,478.

**University of North Dakota**, Grand Forks, ND, Biomass Impacts of SCR Performance, \$60,000.

**University of North Dakota**, Grand Forks, ND, Development and Testing of an Solid Oxide Fuel Cell Gasification System, \$1,250,142.

#### Cycle 2

***Research/Development Projects:***

**University of Florida and American Crystal Sugar East Grand Forks, Minn.**, to research the conversion of biomass into energy and compost through sequential batch anaerobic composting, \$999,995. This project was sponsored by the Prairie Island Indian Community.

#### Cycle 3

***Energy Production Projects:***

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

***Research/Development Projects:***

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

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

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

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

**Northern States Power Company, a Minnesota Corporation**  
**Charitable Contributions / Donations**

Case No. PU-07-776  
 Exhibit \_\_\_\_ (AEH-2)  
 Schedule 2, Page 1 of 8

<b>ELECTRIC</b>	<b>ND</b> <b>2005 Actual</b>	<b>ND</b> <b>2006 Actual</b>	<b>ND</b> <b>2007 Actual</b>	<b>ND</b> <b>2008 Budget</b>
<b>Corporate Contributions</b>				
Community Grants	\$ 24,536	\$ 29,606	\$29,343	
Previous Commitments				
<b>Total Corporate Contributions</b>	<b>\$ 24,536</b>	<b>\$ 29,606</b>	<b>\$29,343</b>	<b>\$37,036</b>
<b>Focus Area Grants</b>				
General Ledget Total				
Arts & Culture	\$ 34,004	\$ 25,178	\$ 25,139	
Community Deveopment	\$ 34,646	\$ 33,432	\$31,808	
Education	\$ 31,671	\$ 4,812	\$ 27,788	
<b>Total Focus Area Grants</b>	<b>\$ 100,320</b>	<b>\$ 63,423</b>	<b>\$ 84,734</b>	<b>\$ 90,531</b>
<b>Matching Gifts Program</b>				
Environmental	\$ 3,334	\$ -	\$ 13,528	
Misc. Foundation				
Volunteer Energy		\$ 2,986	\$ 1,000	
United Way	\$ 20,546	\$ 21,188	\$ 22,530	
Dollars for Doing	\$ 1,167	\$ 970	\$ 1,002	
Not for Profit 501c3	\$ 2,250	\$ 4,333	\$ 2,410	
Higher Education	\$ 6,739	\$ 31,840	\$ 3,003	
<b>Total Matching Grants</b>	<b>\$ 34,036</b>	<b>\$ 61,317</b>	<b>\$ 43,473</b>	<b>\$ 38,119</b>
<b>Total Electric</b>	<b>\$ 158,892</b>	<b>\$ 154,346</b>	<b>\$ 157,550</b>	<b>\$ 165,686</b>
<b>Donations Non-Corp</b>	<b>\$ 30,197</b>	<b>\$ 52,930</b>	<b>\$ 83,079</b>	<b>\$ 6,409</b>
<b>50% Electric Inclusion</b>	<b>\$ 94,545</b>	<b>\$ 103,638</b>	<b>\$120,315</b>	<b>\$86,048</b>

CORPORATE CONTRIBUTIONS	City	State	Total ND Amount	ND Electric
<b>Community Grants</b>				
Fellowship of Christian Athletes	Bismarck	ND	500 ↑	331 Contribution to sponsor Fall Festival 2006
Buffalo Historical Society, Inc.	Buffalo	ND	100 ↑	66 Contribution
North Dakota Community Foundation	Casselton	ND	250 ↑	166 Contribution to Casselton Community Endowment Fund
American National Red Cross	Fargo	ND	1,000 ↑	662 Contribution to local operating Contribution to Cullen Children's Foundation in conjunction with the Celebrity Weekend.
Cullen Childrens Foundation	Fargo	ND	1,000 ↑	662 July 21-22, 2006
Fargo Public Library	Fargo	ND	2,000 ↑	1,324 Contribution to Library
Fargo Theatre Management Corp	Fargo	ND	1,000 ↑	662 Contribution
FirstLink	Fargo	ND	500 ↑	331 Contribution to Holiday Clearing Bureau
FM Rotary Foundation	Fargo	ND	1,000 ↑	662 Contribution to the building of an Easy-Access Playground in Lindenwood Park
Hospice of the Red River Valley	Fargo	ND	1,670 ↑	1,106 Contribution
Lutheran Social Services of North Dakota	Fargo	ND	230 ↑	152 Sponsor Daily Bread Chefs' Gala
Make-A-Wish Foundation of North Dakota	Fargo	ND	600 ↑	397 Sponsor Make-A-Wish Gala on Sept 8
North Dakota 4-H foundation, Inc.	Fargo	ND	250 ↑	166 contribution
North Dakota Caring Foundation Inc.	Fargo	ND	1,000 ↑	662 Contribution to Caring for Children
North Dakota JCI Foundation	Fargo	ND	100 ↑	66 Sponsor Jaycees "Community Halloween"
Rape & Abuse Crisis Center	Fargo	ND	1,000 ↑	662 Contribution to Operations
Red River Zoological Society	Fargo	ND	250 ↑	166 Share-the-care contribution to the zoo
Sisters of the Presentation of the Blessed Virgin Mary	Fargo	ND	1,000 ↑	662 Contribution
Altru Health Foundation	Grand Forks	ND	5,000 ↑	3,310 To support Altru Health Foundation.
Community Foundation of Grand Forks, East Grand Forks and Region	Grand Forks	ND	1,500 ↑	993 To support the Women's Fund and the Patchwork of Possibilities project, which will help promote self-sufficiency for girls & women & the disadvantaged.
North Dakota Special Olympics Inc.	Grand Forks	ND	1,000 ↑	662 Silver Sponsorship for State Summer Games
University of North Dakota Foundation	Grand Forks	ND	5,000 ↑	3,310 To support UND's scholarship program, focused in the math & sciences areas.
MSU Foundation	Mayville	ND	500 ↑	331 To support Mayville State University scholarship fund
American National Red Cross d/b/a American Red Cross Mid-Dakota Chapter	Minot	ND	500 E	500 Funding to provide educational classes and also provide emergency/disaster assistance for the Minot area.
Carnegie Association	Minot	ND	300 E	300 To support varied educational and artistic opportunities for all ages and all abilities
Companions for Children	Minot	ND	500 E	500 Funding to provide mentors to children from single parent homes.
Domestic Violence Prevention Foundation	Minot	ND	500 E	500 Funding to provide shelter and assistance to those in an abusive/crisis situation
Minot Park Foundation	Minot	ND	5,000 E	5,000 Funding for Medal of Honor Memorial that will recognize all ND Medal of Honor recipients Support for Children's Concert for 1200+ regional grade school children will be able to attend an orchestra concert free of charge.
Minot Symphony Association Inc	Minot	ND	1,000 E	1,000 attend an orchestra concert free of charge.
Minot Vocational Adjustment Workshop	Minot	ND	350 E	350 Funding to assist mentally challenged individuals become self-sufficient
Minot Young Mens Christian Association	Minot	ND	2,000 E	2,000 Funding for youth programing for less fortunate youth otherwise unable to participate Funding to support the Wild West Rodeo for Special Kids. Kids with limitations have the opportunity to participate in a rodeo who would otherwise never have that opportunity.
Minot Young Mens Christian Association	Minot	ND	500 E	500 Funding to support the Wild West Rodeo for Special Kids. Kids with limitations have the opportunity to participate in a rodeo who would otherwise never have that opportunity.
Minot Young Mens Christian Association	Minot	ND	500 E	500 opportunity to participate in a rodeo who would otherwise never have that opportunity.
Salvation Army	Minot	ND	350 E	350 Funding for homeless and providing shelter, food and clothing for less fortunate
Blessed Giannas Home Inc.	Minto	ND	400 ↑	265 Contribution to operations
Citizens Scholarship Foundation of America	West Fargo	ND	500 ↑	331 Sponsor scholarship
			<b>38,850</b>	<b>29,606</b>

CORPORATE CONTRIBUTIONS	City	State	Total ND Amount	ND Electric
<b>FOCUS AREA GRANTS</b>				
<u>Arts &amp; Culture</u>				
Fargo-Moorhead Opera Company	Fargo	ND	1,000	662
Future Builders in support of Trollwood Performing Arts School	Fargo	ND	5,000	3,310
Northern Prairie Performing Arts	Fargo	ND	2,000	1,324
Park District of the City of Fargo	Fargo	ND	3,000	1,986
Plains Art Museum	Fargo	ND	5,000	3,310
Red River Human Services Foundation	Fargo	ND	1,000	662
Friends of First Night Greater Grand Forks	Grand Forks	ND	1,000	662
Grand Cities Children's Choir	Grand Forks	ND	1,000	662
Minot Area Council of the Arts Inc.	Minot	ND	1,200	1,200
Minot Art Association	Minot	ND	1,200	1,200
Minot Community Foundation	Minot	ND	5,000	5,000
Norsk Høstfest Association	Minot	ND	5,200	5,200
			<u>31,600</u>	<u>25,178</u>

CORPORATE CONTRIBUTIONS	City	State	Total ND Amount	ND Electric
<b><u>Community Development</u></b>				
Fargo-Moorhead Family YMCA	Fargo	ND	4,300 ↑	2,847
Southeastern North Dakota Community Action Agency	Fargo	ND	13,200 ↑	8,739
Community Violence Intervention Center	Grand Forks	ND	5,000 ↑	3,310
Red River Valley Community Action	Grand Forks	ND	7,000 ↑	4,634
Red River Valley Habitat for Humanity	Grand Forks	ND	1,000 ↑	662
Energy Share of North Dakota	Jamestown	ND	20,000 ↑	13,240
			<u>50,500</u>	<u>33,432</u>
<b><u>Education</u></b>				
NORTH DAKOTA STATE UNIVERSITY ALUMNI ASSOCIATION	FARGO	ND	35 ↑	23
NORTH DAKOTA STATE UNIVERSITY DEVELOPMENT FOUNDATION	FARGO	ND	3,560 ↑	2,357
UNIVERSITY OF NORTH DAKOTA	GRAND FORKS	ND	35 ↑	23
UNIVERSITY OF NORTH DAKOTA FOUNDATION	GRAND FORKS	ND	3,186 ↑	2,109
MINOT STATE UNIVERSITY DEVELOPMENT FOUNDATION	MINOT	ND	300 E	300
			<u>7,116</u>	<u>4,812</u>

Northern States Power Company, a Minnesota Corporation  
 State of North Dakota  
 Year Ended 12/31/2006

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CORPORATE CONTRIBUTIONS	City	State	Total ND Amount	ND Electric
<b>Matching Gifts Program</b>				
<u>Volunteer Energy</u>				
American Cancer Society - Fargo ND	Fargo	ND	1,000 ↑	662
UNITED WAY OF CASS-CLAY	FARGO	ND	1,000 ↑	662
American Heart Association - ND	Jamestown	ND	1,000 ↑	662
YMCA Minot	Minot	ND	1,000 E	1,000
			<u>4,000</u>	<u>2,986</u>
<u>United Way</u>				
Cass-Clay United Way	FARGO	ND	18,905 ↑	12,515
Grand Forks United Way	GRAND FORKS	ND	3,754 ↑	2,485
Souris Valley United Way	MINOT	ND	6,108 E	6,108
Richland-Wilkin United Way	Wahpeton	ND	120 ↑	79
			<u>28,887</u>	<u>21,188</u>
<u>Dollars for Doing</u>				
NORTH DAKOTA SPECIAL OLYMPICS INC	Fargo	ND	210 ↑	139
MINOT HOCKEY BOOSTERS INC	MINOT	ND	500 E	500
Thompson Rural Fire Protection Dist	Thompson	ND	500 ↑	331
			<u>1,210</u>	<u>970</u>
<u>Not for Profit 501c3</u>				
American Cancer Society - Bismarck ND	BISMARCK	ND	100 ↑	66
THE GODS CHILD PROJECT NORTH CENTRAL	BISMARCK	ND	500 ↑	331
American Cancer Society - Fargo ND	Fargo	ND	1,940 ↑	1,284
BOY SCOUTS OF AMERICA COUNCIL	FARGO	ND	25 ↑	17
FARGO-MOORHEAD FAMILY YMCA	FARGO	ND	800 ↑	530
HOSPICE OF THE RED RIVER VALLEY	FARGO	ND	30 ↑	20
PRAIRIE PUBLIC BROADCASTING INC	FARGO	ND	50 ↑	33
UNITED WAY OF CASS-CLAY	FARGO	ND	1,000 ↑	662
ALTRU HEALTH FOUNDATION	GRAND FORKS	ND	100 ↑	66
NORTH DAKOTA MUSEUM OF ART	GRAND FORKS	ND	100 ↑	66
NORTHLANDS RESCUE MISSION INC	GRAND FORKS	ND	100 ↑	66
American Heart Association - ND	Jamestown	ND	25 ↑	17
ANNE CARLSEN CENTER FOR CHILDREN	JAMESTOWN	ND	30 ↑	20
BOY SCOUTS OF AMERICA - Minot ND	Minot	ND	50 E	50
DAKOTA BOYS RANCH FOUNDATION	MINOT	ND	25 E	25
DOMESTIC VIOLENCE PREVENTION FOUNDATION	MINOT	ND	30 E	30
NORTHWEST NORTH DAKOTA GIRL SCOUT FOUNDATION	MINOT	ND	50	50
YMCA Minot	Minot	ND	1,000 E	1,000
			<u>5,955</u>	<u>4,333</u>

CORPORATE CONTRIBUTIONS	City	State	Total ND Amount	ND Electric
<u>Higher Education</u>				
Bismarck State College Foundation	Bismarck	ND	1,000 ↑	662 Bismarck State College Foundation requests scholarship dollars to fund the Xcel Energy Scholarship program for the 2006-07 academic year. These scholarships would enable deserving and qualified students enrolled in the online Power Plant Technology (PWRP), Process Plant Technology (PROP) and Electrical Transmission Systems Technology (ETST) programs at Bismarck State College (BSC) to prepare for future careers in the energy industry. These online energy technology programs work with students across the nation, preparing to fill a critical shortage of trained workers in the energy industry over the next decade. The purpose of this request is to provide scholarship support to youth who wish to participate in the Scouting program. The Northern Lights Council, Boy Scouts of America provides an age appropriate comprehensive educational program for students to build character, learn to take responsibility and develop personal fitness. The Northern Lights Council, Boy Scouts of America partners with local educators, businesses and community organizations to offer Scouting programs.
Boy Scouts of America, Northern Lights Council	Fargo	ND	2,000 ↑	1,324 The FPS Development Foundation requests \$2,500 to provide innovative math and science grants to FPS teachers and schools. There continues to be an emphasis on the need for students to consider a career in science and math in order for American companies to remain competitive on a global basis. Providing these grants to FPS teachers and schools, not only challenges teachers to use new instructive techniques, but provide students with learning opportunities that will spark and stimulate their interest in math and science.
Fargo Public Schools Development Foundation	Fargo	ND	2,500 ↑	1,655 North Dakota State University's College of Engineering & Architecture prepares students to use their Math and Science acumen to design the future. We are requesting funds to support Xcel Energy named student scholarships for engineering students(\$15,000) and also to support the engineering students' solar car entry in the Formula Sun Grand Prix and the American Solar Challenge. (\$1,000).
North Dakota State University Development Foundation	Fargo	ND	16,000 ↑	10,592 The Junior Achievement Program teaches economics and the value of the free enterprise system to over 2300 elementary school students in 16 area schools in the Grand Forks area. The goal is to make our students more workforce ready and realize the important connection of education to their future success in the working world. Over 120 educators and 130 community and business volunteers partner to deliver the program.
Grand Forks Public Schools	Grand Forks	ND	3,000 ↑	1,986 Provide scholarships to University of North Dakota students, with an emphasis given on math, science, technology and engineering. The beneficiaries of this project are current UND students in science, math, technology and engineering. For many students, a scholarship can make a difference between attending college or not being able to pursue a degree at all due to limited resources. These are Xcel Energy named scholarships. This grant will allow continued program development of the six weeks of summer camp. This camp is open to members as well as non-members of Girl Scouts providing opportunities for youth that would not otherwise have the opportunity to attend an educational camp. Scholarships are also provided for youth to attend this camp. The girls will earn badges pertaining to math, science, environment, financial literacy as well as other areas.
University of North Dakota Foundation	Grand Forks	ND	10,000 ↑	6,620 To help continue to provide the Junior Achievement program in the Minot area. The JA program helps students to understand and grasp economics and the free enterprise system.
Girls Scouts of Northwest North Dakota	Minot	ND	1,000 E	1,000
Minot Community Foundation	Minot	ND	2,000 E	2,000

CORPORATE CONTRIBUTIONS	City	State	Total ND Amount		ND Electric
					(1) To provide additional professional development for area educators on service learning and encourage the integration of such projects which involve participation and partnership among, students, educators, business, nonprofit entities, and community members in our area.
Minot Public Schools	Minot	ND	2,000	E	2,000 (2) To enhance the career development program by funding a motivational speaker for 9th & 10th grade students and offering all 9th grade students career sessions hosted by local professionals addressing the knowledge and skills needed to effectively compete in the job market in their respective career fields.
Minot State University Development Foundation	Minot	ND	4,000	E	4,000 Requesting funding to support student scholarships in the sum of \$4,000. These Xcel Energy scholarships will greatly assist students pursuing careers in science, mathematics, technical and/or environmental areas of study. Scholarships allow many students to pursue a more technical area of study.
			<u>43,500</u>		<u>31,840</u>

Northern States Power Company, a Minnesota Corporation  
 State of North Dakota  
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CORPORATE CONTRIBUTIONS	City	State	Total ND Amount	ND Electric
<b>State of North Dakota Management Donations</b>				
<u>Name</u>				
AMERICAN HEART ASSOCIATION: 200			110	100
AMERICAN RED CROSS: SPONSORSHI			200	182
DOWNTOWN LEADERSHIP GROUP: 200			500	455
EASTER SEALS GOODWILL: 2006 CO			200	182
IAAP RED RIVER CHAPTER: SPONSO			200	182
I HELP INC: SPONSORSHIP OF HOR			125	114
MARCH OF DIMES SPONSORSHIP			250	228
MINOT AM LEGION SPONSORSHIP GI			175	159
Minot Area Safety Assoc; Dues			100	91
Minot High After Graduation Co			75	68
MINOT MUSIC BOOSTERS SCHOLARSH			75	68
MINOT PS SPONSORSHIP			200	200
Minot State Beaver Boosters; M			550	501
MSUM ALUMNI FOUNDATION: SPONSO			500	455
National Council for Public Pr			750	683
NDSU Research & Technology Par			38,500	35,035
NDSU SAE; Sponsor			2,000	1,820
North Dakota League of Cities;			1,000	910
NORTH DAKOTA MUSEUM OF ART: PA			1,000	910
Northern Lights Council 429 -			1,250	1,138
Northern Lights Council - Spon			500	455
Our Redeemer's Christian Schoo			125	114
Pheasants Forever; Sponsor Ann			250	228
Red River Valley Community Act			620	564
Senior All-Night Party; Sponso			200	182
Talent Productions; Caricature			1,050	956
TAUBE MUSEUM OF ART: 06/30/06;			200	182
Taube Museum of Art; Sponsorsh			200	182
The Heritage Singers; Sponsors			50	46
UND Foundation; Sponsorship of			2,500	2,275
United Way of Cas-Clay - Kick-			2,500	2,275
Ward County Treasurer; Sponsor			250	228
Washington Elementary School;			100	91
West Fargo COC; Sponsor Annual			300	273
Women of Distinction YWCA - 20			100	91
Zion Lutheran Church; Sponsors			100	91
GRAND FORKS/ CATS INCR SPONSO			1,000	910
GRAND FORKS/ PLAQUES & ENGRAV			40	36
GRAND FORKS/UNDERWRITE BGEA PU			300	273
			<b>58,145</b>	<b>52,930</b>
<b>TOTAL CONTRIBUTIONS</b>			<b>269,763</b>	<b>207,276</b>
<b>For 50% INCLUSION ( 2006 Acutals)</b>				<b>103,638</b>

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**Incentive Compensation Adjustment**

**Comparison of Excluding 25% of Base Pay to Excluding 15% of Base Pay**

			Initial Filing	Recommended by Staff
	2008 Budget Amounts for NSP	NSP Electric	North Dakota Electric Jurisdiction less amount over 25%	North Dakota Electric Jurisdiction less amount over 15%
Total Identified in Base Data as Incentive	19,191,434	17,478,349	1,006,508	1,006,508
Less Lobbying Amount not includable (FERC 426)	(45,320)	(41,409)	(1,258)	(1,258)
<b>Incentive Net of Lobbying</b>	19,146,114	17,436,940	1,005,250	1,005,250
Less Long Term Plan	(4,751,115)	(4,384,719)	(233,739)	(233,739)
Less Other Bonuses/Incentives	(739,500)	(739,500)	(43,475)	(43,475)
<b>Less Amount Over % of Base Pay</b>	<b>(1,508,166)</b>	<b>(1,344,053)</b>	<b>(45,151)</b>	<b>(79,243)</b>
<b>Net Amount of Base Incentive to be included in rates</b>	<b>12,147,333</b>	<b>10,968,668</b>	<b>682,885</b>	<b>648,793</b>
<b>Total Adjustment to Incentive with 15% Exclusion</b>	<b>(6,998,781)</b>	<b>(6,468,272)</b>		<b>(356,457)</b>
<b>Total Adjustment to Incentive with 25% Exclusion</b>	<b>(6,349,945)</b>	<b>(5,890,040)</b>	<b>(322,365)</b>	
<b>Change from Amount in Original Filing Adjustment</b>	<b>(648,836)</b>	<b>(578,232)</b>	-	<b>\$ (34,092)</b>

<b>King-Prod</b>	Dec-2007	Jan-2008	Feb-2008	Mar-2008	Apr-2008	May-2008	Jun-2008	Jul-2008	Aug-2008	Sep-2008	Oct-2008	Nov-2008	Dec-2008
<b>Rate Base</b>													
Plus CWIP Ending Balance	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Plant In-Service	477,403,752	477,403,752	477,403,752	477,403,752	477,403,752	477,403,752	477,403,752	477,403,752	477,403,752	477,403,752	477,403,752	477,403,752	477,403,752
Less Book Depreciation Reserve	5,467,202	6,489,770	7,512,339	8,534,907	9,557,475	10,580,044	11,602,612	12,625,180	13,647,749	14,670,317	15,692,886	16,715,454	17,738,022
Less Accum Deferred Taxes	(2,114,362)	(1,362,252)	(610,141)	141,969	894,080	1,646,190	2,398,301	3,150,411	3,902,522	4,654,632	5,406,742	6,158,853	6,910,963
End Of Month Rate Base	474,050,912	472,276,234	470,501,555	468,726,876	466,952,197	465,177,518	463,402,839	461,628,161	459,853,482	458,078,803	456,304,124	454,529,445	452,754,767
<b>Average Rate Base (BOM/EOM)</b>	<b>474,886,436</b>	<b>473,163,573</b>	<b>471,388,894</b>	<b>469,614,215</b>	<b>467,839,537</b>	<b>466,064,858</b>	<b>464,290,179</b>	<b>462,515,500</b>	<b>460,740,821</b>	<b>458,966,142</b>	<b>457,191,464</b>	<b>455,416,785</b>	<b>453,642,106</b>
<b>Calculation of Return</b>													
Plus Debt Return	1,325,725	1,320,915	1,315,961	1,311,006	1,306,052	1,301,098	1,296,143	1,291,189	1,286,235	1,281,280	1,276,326	1,271,372	1,266,418
Plus Equity Return	2,109,287	2,101,635	2,093,752	2,085,870	2,077,987	2,070,105	2,062,222	2,054,340	2,046,457	2,038,575	2,030,692	2,022,810	2,014,927
<b>Total Return</b>	<b>3,435,012</b>	<b>3,422,550</b>	<b>3,409,713</b>	<b>3,396,876</b>	<b>3,384,039</b>	<b>3,371,202</b>	<b>3,358,366</b>	<b>3,345,529</b>	<b>3,332,692</b>	<b>3,319,855</b>	<b>3,307,018</b>	<b>3,294,181</b>	<b>3,281,345</b>
<b>Income Statement Items</b>													
Plus Avoided Property Taxes	0	(28,250)	(28,250)	(28,250)	(28,250)	(28,250)	(28,250)	(28,250)	(28,250)	(28,250)	(28,250)	(28,250)	(28,250)
Plus Property Taxes	0	257,455	257,455	257,455	257,455	257,455	257,455	257,455	257,455	257,455	257,455	257,455	257,455
Plus Book Depreciation	1,022,360	1,022,568	1,022,568	1,022,568	1,022,568	1,022,568	1,022,568	1,022,568	1,022,568	1,022,568	1,022,568	1,022,568	1,022,568
Plus Deferred Taxes	798,687	752,110	752,110	752,110	752,110	752,110	752,110	752,110	752,110	752,110	752,110	752,110	752,110
Plus Current Taxes	611,702	638,415	633,747	629,078	624,410	619,741	615,073	610,404	605,736	601,068	596,399	591,731	587,062
<b>Total Income Statement Expense</b>	<b>2,432,749</b>	<b>2,642,299</b>	<b>2,637,631</b>	<b>2,632,962</b>	<b>2,628,294</b>	<b>2,623,625</b>	<b>2,618,957</b>	<b>2,614,289</b>	<b>2,609,620</b>	<b>2,604,952</b>	<b>2,600,283</b>	<b>2,595,615</b>	<b>2,590,946</b>
<b>Total Revenue Requirements</b>	<b>5,867,761</b>	<b>6,064,849</b>	<b>6,047,344</b>	<b>6,029,839</b>	<b>6,012,333</b>	<b>5,994,828</b>	<b>5,977,323</b>	<b>5,959,817</b>	<b>5,942,312</b>	<b>5,924,807</b>	<b>5,907,301</b>	<b>5,889,796</b>	<b>5,872,291</b>
<b>Jurisdictional Revenue Requirement</b>	<b>279,458</b>	<b>296,099</b>	<b>295,245</b>	<b>294,390</b>	<b>293,535</b>	<b>292,681</b>	<b>291,826</b>	<b>290,972</b>	<b>290,117</b>	<b>289,262</b>	<b>288,408</b>	<b>287,553</b>	<b>286,698</b>
<b>Tax Depreciation</b>	<b>2,912,213</b>	<b>2,798,372</b>	<b>2,798,372</b>	<b>2,798,372</b>	<b>2,798,372</b>	<b>2,798,372</b>	<b>2,798,372</b>	<b>2,798,372</b>	<b>2,798,372</b>	<b>2,798,372</b>	<b>2,798,372</b>	<b>2,798,372</b>	<b>2,798,372</b>
CPI	0	0	0	0	0	0	0	0	0	0	0	0	0
<b>Manufacturer Prod Deduct</b>	<b>83,169</b>	<b>88,785</b>	<b>88,135</b>	<b>87,486</b>	<b>86,837</b>	<b>86,188</b>	<b>85,539</b>	<b>84,889</b>	<b>84,240</b>	<b>83,591</b>	<b>82,942</b>	<b>82,292</b>	<b>81,643</b>
<b>Removal of Old Plant</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>

	BOY	EOY	Average	ND Only
<b>Rate Base</b>				
Plus Plant In-Service	477,403,752	477,403,752	477,403,752	23,307,913
Less Book Depreciation Reserve	5,467,202	17,738,022	11,602,612	566,465
Less Accum Deferred Taxes	(2,114,362)	6,910,963	2,398,301	117,090
End Of Month Rate Base	474,050,912	452,754,767	463,402,839	22,624,358
<b>Average Rate Base (BOY/EOY)</b>	<b>2008 Annual</b>	<b>ND Only</b>		
	<b>463,402,839</b>	<b>22,624,358</b>		
<b>Calculation of Return</b>				
Plus Debt Return	15,523,995	757,916		
Plus Equity Return	24,699,371	1,205,878		
<b>Total Return</b>	<b>40,223,366</b>	<b>1,963,794</b>		
<b>Income Statement Items</b>				
Plus Book Depreciation	12,270,820	599,089		
Plus Deferred Taxes	9,025,326	440,636		
Plus Current Taxes	7,352,864	358,983		
<b>Total Income Statement Expense</b>	<b>28,649,010</b>	<b>1,398,708</b>		
<b>Total Revenue Requirements</b>	<b>68,872,377</b>	<b>3,362,503</b>		
Interchange Demand	64.4383%			
Jurisdiction Demand	5.7820%			
Interchangeed Composite Allocator	4.8822%			
<b>Jurisdictional Revenue Requirement</b>	<b>3,362,503</b>			
<b>Tax Depreciation</b>	<b>33,580,463</b>			
CPI	0			
<b>Manufacturer Prod Deduct</b>	<b>1,022,567</b>			
<b>Removal of Old Plant</b>	<b>0</b>			
<b>State of ND Composite Tax Rate</b>	<b>39.225%</b>			

High Bridge-Prod	Dec-2007	Jan-2008	Feb-2008	Mar-2008	Apr-2008	May-2008	Jun-2008	Jul-2008	Aug-2008	Sep-2008	Oct-2008	Nov-2008	Dec-2008
<b>Rate Base</b>													
Plus CWIP Ending Balance	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Plant In-Service	0	0	0	0	0	361,136,670	364,208,687	365,651,778	367,678,463	368,171,235	368,617,071	369,062,907	369,508,709
Less Book Depreciation Reserve	0	0	0	0	0	0	0	1,040,943	2,091,604	3,150,548	4,215,547	5,286,423	6,363,101
Less Accum Deferred Taxes	(3,198,556)	(3,147,343)	(3,095,255)	(3,073,673)	(3,024,505)	(2,808,024)	(2,167,091)	(614,967)	907,544	2,430,399	3,942,724	5,435,892	6,934,907
End Of Month Rate Base	3,198,556	3,147,343	3,095,255	3,073,673	3,024,505	363,944,694	366,375,778	365,225,802	364,679,315	362,590,287	360,458,800	358,340,592	356,210,701
<b>Average Rate Base (BOM/EOM)</b>	<b>3,148,114</b>	<b>3,172,950</b>	<b>3,121,299</b>	<b>3,084,464</b>	<b>3,049,089</b>	<b>183,484,600</b>	<b>365,160,236</b>	<b>365,800,790</b>	<b>364,952,558</b>	<b>363,634,801</b>	<b>361,524,544</b>	<b>359,399,696</b>	<b>357,275,647</b>
<b>Calculation of Return</b>													
Plus Debt Return	8,788	8,858	8,714	8,611	8,512	512,228	1,019,406	1,021,194	1,018,826	1,015,147	1,009,256	1,003,324	997,395
Plus Equity Return	13,983	14,093	13,864	13,700	13,543	814,977	1,621,920	1,624,765	1,620,998	1,615,145	1,605,772	1,596,334	1,586,899
<b>Total Return</b>	<b>22,771</b>	<b>22,951</b>	<b>22,577</b>	<b>22,311</b>	<b>22,055</b>	<b>1,327,205</b>	<b>2,641,326</b>	<b>2,645,959</b>	<b>2,639,824</b>	<b>2,630,292</b>	<b>2,615,028</b>	<b>2,599,658</b>	<b>2,584,294</b>
<b>Income Statement Items</b>													
Plus Avoided Property Taxes	0	(60,417)	(60,417)	(60,417)	(60,417)	(60,417)	(60,417)	(60,417)	(60,417)	(60,417)	(60,417)	(60,417)	(60,417)
Plus Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Book Depreciation	0	0	0	0	0	0	0	1,040,943	1,050,660	1,058,945	1,064,999	1,070,876	1,076,677
Plus Deferred Taxes	(100,885)	51,213	52,089	21,582	49,167	216,481	640,933	1,552,124	1,522,511	1,522,855	1,512,324	1,493,168	1,499,015
Plus Current Taxes	650,022	500,573	516,430	558,201	554,068	598,044	411,807	(334,437)	(310,947)	(314,432)	(310,748)	(299,710)	(310,120)
<b>Total Income Statement Expense</b>	<b>549,137</b>	<b>471,369</b>	<b>488,102</b>	<b>499,366</b>	<b>522,818</b>	<b>734,108</b>	<b>972,323</b>	<b>2,178,213</b>	<b>2,181,808</b>	<b>2,186,951</b>	<b>2,186,158</b>	<b>2,183,917</b>	<b>2,185,156</b>
<b>Total Revenue Requirements</b>	<b>571,909</b>	<b>494,320</b>	<b>510,679</b>	<b>521,677</b>	<b>544,873</b>	<b>2,061,313</b>	<b>3,613,649</b>	<b>4,824,173</b>	<b>4,821,632</b>	<b>4,817,242</b>	<b>4,801,185</b>	<b>4,783,575</b>	<b>4,769,450</b>
<b>Jurisdictional Revenue Requirement</b>	<b>27,238</b>	<b>24,134</b>	<b>24,932</b>	<b>25,469</b>	<b>26,602</b>	<b>100,638</b>	<b>176,426</b>	<b>235,527</b>	<b>235,403</b>	<b>235,188</b>	<b>234,405</b>	<b>233,545</b>	<b>232,855</b>
<b>Tax Depreciation</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>2,977,555</b>	<b>2,997,822</b>	<b>3,003,982</b>	<b>3,011,412</b>	<b>3,022,558</b>	<b>3,044,848</b>
CPI	1,641,273	1,677,839	1,728,447	1,775,678	1,835,212	938,317	2,538	7	0	0	0	0	0
Manufacturer Prod Deduct	88,379	69,615	71,820	77,629	77,055	83,170	57,270	(46,510)	(43,244)	(43,728)	(43,216)	(41,681)	(43,129)
Removal of Old Plant	472,469	897,945	922,425	868,458	962,398	959,998	1,570,070	1,804,970	1,721,370	1,723,870	1,696,370	1,643,870	1,641,370

Rate Base	TY HB ND			ALT HB ND Adjusted ND	
	BOY	EOY	Average	ND Only	Adjusted ND
Plus Plant In-Service	0	369,508,709	184,754,355	9,020,119	2,267,878
Less Book Depreciation Reserve	0	6,363,101	3,181,550	155,330	94,495
Less Accum Deferred Taxes	(3,198,556)	6,934,907	1,868,175	91,208	7,719
End Of Month Rate Base	3,198,556	356,210,701	179,704,629	8,773,580	2,165,664
<b>Average Rate Base (BOY/EOY)</b>	<b>2008 Annual</b>	<b>ND Only</b>	<b>Alt Plan ND</b>	<b>Adjustment ND</b>	
	179,704,629	8,773,580	2,165,664	6,607,916	
<b>Calculation of Return</b>					
Plus Debt Return	6,020,105	293,915	72,550	221,365	
Plus Equity Return	9,578,257	467,632	115,430	352,202	
<b>Total Return</b>	<b>15,598,362</b>	<b>761,547</b>	<b>187,980</b>	<b>573,567</b>	
<b>Income Statement Items</b>					
Plus Book Depreciation	6,363,101	310,661	188,990	121,671	
Plus Deferred Taxes	10,133,463	494,738	15,438	479,300	
Plus Current Taxes	(395,951)	(19,331)	53,412	(72,743)	
<b>Total Income Statement Expense</b>	<b>16,100,613</b>	<b>786,068</b>	<b>257,840</b>	<b>528,228</b>	
<b>Total Revenue Requirements</b>	<b>31,698,974</b>	<b>1,547,614</b>	<b>445,820</b>	<b>1,101,795</b>	
Interchange Demand	84.4383%				
Jurisdiction Demand	5.7820%				
Interchange Composite Allocator	4.8822%				
<b>Jurisdictional Revenue Requirement</b>	<b>1,547,614</b>				
<b>Tax Depreciation</b>	<b>18,058,177</b>				
<b>CPI</b>	<b>7,958,038</b>				
<b>Manufacturer Prod Deduct</b>	<b>175,052</b>				
<b>Removal of Old Plant</b>	<b>16,413,114</b>				
<b>State of ND Composite Tax Rate</b>	<b>39.225%</b>				

See HB Alt tab for details

High Bridge Prod Alt	Dec-2007	Jan-2008	Feb-2008	Mar-2008	Apr-2008	May-2008	Jun-2008	Jul-2008	Aug-2008	Sep-2008	Oct-2008	Nov-2008	Dec-2008
<b>Rate Base</b>													
Plus CWIP Ending Balance	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Plant In-Service	0	0	0	0	0	92,903,500	92,903,500	92,903,500	92,903,500	92,903,500	92,903,500	92,903,500	92,903,500
Less Book Depreciation Reserve	0	0	0	0	0	258,065	774,196	1,290,326	1,806,457	2,322,588	2,838,718	3,354,849	3,870,979
Less Accum Deferred Taxes	0	0	0	0	0	131,755	158,105	184,456	210,807	237,158	263,509	289,860	316,211
End Of Month Rate Base	0	0	0	0	0	92,513,680	91,971,199	91,428,717	90,886,236	90,343,754	89,801,273	89,258,791	88,716,310
<b>Average Rate Base (BOM/EOM)</b>	0	0	0	0	0	46,256,840	92,242,439	91,699,958	91,157,476	90,614,995	90,072,514	89,530,032	88,987,551
<b>Calculation of Return</b>													
Plus Debt Return	0	0	0	0	0	129,134	257,510	255,996	254,481	252,967	251,452	249,938	248,424
Plus Equity Return	0	0	0	0	0	205,457	409,710	407,301	404,891	402,482	400,072	397,663	395,253
<b>Total Return</b>	0	0	0	0	0	334,591	667,220	663,296	659,372	655,448	651,525	647,601	643,677
<b>Income Statement Items</b>													
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Book Depreciation	0	0	0	0	0	258,065	516,131	516,131	516,131	516,131	516,131	516,131	516,131
Plus Deferred Taxes	0	0	0	0	0	131,755	26,351	26,351	26,351	26,351	26,351	26,351	26,351
Plus Current Taxes	0	0	0	0	0	8,665	220,049	218,622	217,195	215,768	214,341	212,914	211,487
<b>Total Income Statement Expense</b>	0	0	0	0	0	398,485	762,530	761,103	759,676	758,249	756,822	755,395	753,968
<b>Total Revenue Requirements</b>	0	0	0	0	0	733,076	1,429,751	1,424,400	1,419,049	1,413,698	1,408,347	1,402,996	1,397,645
<b>Jurisdictional Revenue Requirement</b>	0	0	0	0	0	35,790	69,804	69,542	69,281	69,020	68,759	68,497	68,236
<b>Tax Depreciation</b>	0	0	0	0	0	580,647	580,647	580,647	580,647	580,647	580,647	580,647	580,647
CPI	0	0	0	0	0	0	0	0	0	0	0	0	0
Manufacturer Prod Deduct	0	0	0	0	0	1,205	30,602	30,404	30,205	30,007	29,808	29,610	29,412
Removal of Old Plant	0	0	0	0	0	0	0	0	0	0	0	0	0

	BOY	EOY	Average	ND Only
<b>Rate Base</b>				
Plus Plant In-Service	0	92,903,500	46,451,750	2,267,878
Less Book Depreciation Reserve	0	3,870,979	1,935,490	94,495
Less Accum Deferred Taxes	0	316,211	158,105	7,719
End Of Month Rate Base	0	88,716,310	44,358,155	2,165,664
<b>Average Rate Base (BOY/EOY)</b>				
	2008 Annual	ND Only		
	44,358,155	2,165,664		
<b>Calculation of Return</b>				
Plus Debt Return	1,485,998	72,550		
Plus Equity Return	2,364,290	115,430		
<b>Total Return</b>	3,850,288	187,980		
<b>Income Statement Items</b>				
Plus Book Depreciation	3,870,979	188,990		
Plus Deferred Taxes	316,211	15,438		
Plus Current Taxes	1,094,009	53,412		
<b>Total Income Statement Expense</b>	5,281,199	257,840		
<b>Total Revenue Requirements</b>	9,131,487	445,820		
Interchange Demand	84.4383%			
Jurisdiction Demand	5.7820%			
Interchangeed Composite Allocator	4.8822%			
<b>Jurisdictional Revenue Requirement</b>	445,820			

Construction Cost:  
In May 2002 Filing (2001 \$) \$ 71,000,000  
Inflation Factor (2001-2008) 1.3085  
2008 EOY Plant In Service \$ 92,903,500

Assumptions:  
In Service Date May-08  
Book Life 15 years  
Tax Life 15 years

Tax Depreciation	4,645,175
CPI	0
Manufacturer Prod Deduct	211,254
Removal of Old Plant	0
State of ND Composite Tax Rate	39.225%

**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-07-776  
Exhibit \_\_\_\_ (AEH-2)  
Schedule 5, Page 1 of 2

<u>Line No.</u>	<u>Description</u>	<u>Initial Petition</u> (1)	<u>Income Statement</u> (2)	<u>Rebuttal Position</u> (3)
	Electric Plant as Booked			
1	Production	\$356,704		\$356,704
2	Transmission	\$87,557		\$87,557
3	Distribution	\$124,202		\$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	\$607,339		\$607,339
	Reserve for Depreciation			
8	Production	\$234,339		\$234,339
9	Transmission	\$29,941		\$29,941
10	Distribution	\$48,239		\$48,239
11	General	\$6,955		\$6,955
12	Common	\$13,692		\$13,692
13	TOTAL Reserve for Depreciation	\$333,166		\$333,166
	Net Utility Plant in Service			
14	Production	\$122,365		\$122,365
15	Transmission	\$57,616		\$57,616
16	Distribution	\$75,964		\$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	\$274,173		\$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	\$40,717		\$40,717
24	Cash Working Capital	\$1,136	\$8	1,144
	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
32	Customer Advances	(\$60)		(\$60)
33	Other Working Capital	\$797		\$797
34	Total Other Rate Base Items	\$2,706	\$0	\$2,706
35	Total Average Rate Base	\$242,100	\$8	\$242,108

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-07-776  
Exhibit \_\_\_ (AEH-2)  
Schedule 5, Page 2 of 2

Line No.	Description	Initial Petition	MISO Sch 16 & 17 Margin Adj 1	Nuclear Refueling Outage Change of Accounting 2	Allen S King Chemical Cost Correction 3	Cost of Debt 4	CWC 5	Rebuttal Position (1)
<b>Operating Revenues</b>								
1	Retail	\$147,179	\$532					\$147,711
2	CIP Revenue Adjustment	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>\$532</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$187,236</b>
<b>Expenses</b>								
Operating Expenses:								
7	Fuel & Purchased Energy	\$79,015						\$79,015
8	Power Production	40,491		(173)	(322)			\$39,996
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	Sales, Econ Dvlp & Other	2						\$2
14	Administrative & General	10,399						\$10,399
15	Amortization	460						\$460
16	<b>Total Operating Expenses</b>	<b>\$148,725</b>	<b>\$0</b>	<b>(\$173)</b>	<b>(\$322)</b>	<b>\$0</b>	<b>\$0</b>	<b>\$148,230</b>
17	Depreciation	\$19,160						\$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	209	68	126	19	(0)	\$636
22	Payroll & Other	1,310						\$1,310
23	<b>Total Taxes</b>	<b>\$9,025</b>	<b>\$209</b>	<b>\$68</b>	<b>\$126</b>	<b>\$19</b>	<b>(\$0)</b>	<b>\$9,447</b>
24	<b>Total Expenses</b>	<b>\$176,910</b>	<b>\$209</b>	<b>(\$105)</b>	<b>(\$195)</b>	<b>\$19</b>	<b>(\$0)</b>	<b>\$176,837</b>
25	Allowance for Funds Used During Construction	\$0				\$0	\$0	\$0
26	<b>Total Operating Income</b>	<b>\$9,794</b>	<b>\$323</b>	<b>\$105</b>	<b>\$195</b>	<b>(\$19)</b>	<b>\$0</b>	<b>\$10,399</b>

Note: (1) Electric Utility - North Dakota Jurisdiction

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

Case No. PU-07-776  
 Exhibit \_\_\_ (AEH-2)  
 Schedule 6, Page 1 of 1

<u>Line</u>	<u>Description</u>	<u>Initial Petition</u>	<u>Company Proposed Adjustments</u>	<u>Rebuttal Position</u>
1	Average Rate Base	\$242,100	\$8	\$242,108
2	Operating Income (Before AFUDC)	\$9,794	\$605	\$10,399
3	Allowance for Funds Used During Construction	\$0	\$0	0
4	Total Available for Return (Line 2 + Line 3 + Rounding)	\$9,794	\$605	\$10,399
5	Overall Rate of Return (Line 4 / Line 1)	4.05%	0.25%	4.30%
6	Required Rate of Return	9.20%	-0.40%	8.80%
7	Operating Income Requirement (Line 1 x Line 6)	\$22,273	(\$968)	\$21,306
8	Income Deficiency (Line 7 - Line 6)	\$12,479	(\$1,573)	\$10,906
9	Gross Revenue Conversion Factor	1.64555	0.00000	1.64555
10	Revenue Deficiency (Line 8 x Line 9)	\$20,535	(\$2,589)	\$17,946
11	Retail Related Revenue Under Present Rates	\$147,179	\$532	\$147,711
13	Percentage Increase Needed in Overall Revenue (Line 10 / Line 11)	13.95%	-1.80%	12.15%

**ROE = 2.06%**  
**Deficiency = \$17,946**  
**% Increase = 12.15%**  
**Required ROE = 10.75%**

**Northern States Power Company (MN)  
Electric Utility - North Dakota Retail Jurisdiction  
Cost of Service Study  
2008 Rebuttal**

**Summary Reports**

**June 13, 2008**

**Northern States Power Company (MN)  
Electric Utility - North Dakota Retail Jurisdiction  
Cost of Service Study  
2008 Rebuttal**

Case No. PU-07-776  
Exhibit \_\_\_\_ (AEH-2)  
Schedule 7, Page 2 of 6

(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	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	12,347	12,347	12,347	1,144	1,144	1,144	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 Prepays & 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>4,436,604</b>	<b>4,996,907</b>	<b>4,716,755</b>	<b>219,115</b>	<b>265,103</b>	<b>242,108</b>	<b>4,217,489</b>	<b>4,731,804</b>	<b>4,474,646</b>

Northern States Power Company (MN)  
 Electric Utility - North Dakota Retail Jurisdiction  
 Cost of Service Study  
 2008 Rebuttal

Case No. PU-07-776  
 Exhibit \_\_\_ (AEH-2)  
 Schedule 7, Page 3 of 6

(Dollars in Thousands)

**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	147,711	2,729,402
2	CIP Adjustment to Program Costs	0	0	0
3	Interdepartmental	434	0	434
4	Other Operating	725,631	39,525	686,106
5	Gross Earnings Tax	0	0	0
6	<b>Total Operating Revenues</b>	<b>3,603,178</b>	<b>187,236</b>	<b>3,415,942</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	39,996	646,186
9	Transmission	138,216	7,992	130,224
10	Distribution	110,071	5,655	104,416
11	Customer Accounting	59,420	4,343	55,077
12	Customer Service & Information	60,501	369	60,133
13	Sales, Econ Dvlp & Other	138	2	136
14	Administrative & General	161,492	10,399	151,093
15	<b>Total Operating Expenses</b>	<b>2,560,030</b>	<b>147,770</b>	<b>2,412,260</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)	86,603	636	85,967
22	Payroll & Other	21,401	1,310	20,091
23	<b>Total Taxes</b>	<b>277,659</b>	<b>9,447</b>	<b>268,212</b>
24	<b>Total Expenses</b>	<b>3,230,970</b>	<b>176,837</b>	<b>3,054,133</b>
25	AFUDC	0	0	0
26	<b>Total Operating Income</b>	<b>372,208</b>	<b>10,399</b>	<b>361,809</b>

Northern States Power Company (MN)  
 Electric Utility - North Dakota Retail Jurisdiction  
 Cost of Service Study  
 2008 Rebuttal

(Dollars in Thousands)

Case No. PU-07-776  
 Exhibit \_\_\_\_ (AEH-2)  
 Schedule 7, Page 4 of 6

Income Tax Summary

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>
<u>Income Before Taxes</u>			
1 Total Operating Revenues	3,603,178	187,236	3,415,942
2 less: Total Operating Expenses	(2,560,030)	(147,770)	(2,412,260)
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>11,035</b>	<b>447,776</b>
<u>Tax Additions</u>			
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>
<u>Tax Deductions</u>			
18 Tax Depreciation & Removal Expense	665,489	30,605	634,884
19 Debt Interest Expense	152,351	7,820	144,531
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>818,851</b>	<b>38,489</b>	<b>775,579</b>
24 <b>State Taxable Income</b>	<b>212,040</b>	<b>1,621</b>	<b>210,419</b>
25 State Income Tax Rate	8.99%	6.51%	N/A
26 <b>Total State Income Taxes</b>	<b>19,060</b>	<b>106</b>	<b>18,955</b>
27 <b>Federal Taxable Income</b>	<b>192,979</b>	<b>1,516</b>	<b>191,464</b>
28 Federal Income Tax Rate	35.00%	35.00%	35.00%
29 <b>Total Federal Income Taxes</b>	<b>67,543</b>	<b>530</b>	<b>67,012</b>
30 <b>Total Federal &amp; State Income Taxes</b>	<b>86,603</b>	<b>636</b>	<b>85,967</b>

Northern States Power Company (MN)  
 Electric Utility - North Dakota Retail Jurisdiction  
 Cost of Service Study  
 2008 Rebuttal

Case No. PU-07-776  
 Exhibit \_\_\_ (AEH-2)  
 Schedule 7, 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	6.7600%	45.6100%	3.0800%	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	10.7500%	51.7700%	5.5700%	<b>Total North Dakota Composite Tax Rate</b>	<b>39.23%</b>
5	<b>Required Rate of Return</b>			<b>8.8000%</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>Rate of Return (ROR)</b>			
6	Total Operating Income	372,208	10,399
7	Total Average Rate Base	4,716,755	242,108
8	<b>ROR (Operating Income / Rate Base)</b>	<b>7.89%</b>	<b>4.30%</b>
<b>Return on Equity (ROE)</b>			
9	Total Operating Income	372,208	10,399
10	Debt Interest (Rate Base * Weighted Debt Cost)	(152,351)	(7,820)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0
12	Earnings Available for Common	219,857	2,579
13	Equity Rate Base ( Rate Base * Equity Ratio)	2,441,864	125,339
14	<b>ROE (Earnings for Common / Equity Rate Base)</b>	<b>9.00%</b>	<b>2.06%</b>
<b>Revenue Deficiency</b>			
15	Require Operating Income (Rate Base * Required Return)	415,074	21,306
16	Operating Income	372,208	10,399
17	Operating Income Deficiency	42,867	10,906
18	Revenue Conversion Factor ( 1/(1-Composite Tax Rate) )	1.69041	1.64555
19	<b>Revenue Deficiency (Income Deficiency * Conversion Fac</b>	<b>72,463</b>	<b>17,946</b>
<b>Total Retail Revenue Requirements</b>			
20	Retail Related Revenues	2,877,547	147,711
21	Revenue Deficiency	72,463	17,946
22	<b>Total Retail Revenue Requirements</b>	<b>2,950,010</b>	<b>165,657</b>
23	<b>Percentage Increase (Decrease)</b>	<b>2.52%</b>	<b>12.15%</b>

(Dollars In Thousands)

**Rate Base Detail - Cash Working Capital**

Expenses	Lead Days	Total Company Electric		ND Retail Electric		All Other	
		Dollars	Dollar x Days	Dollars	Dollar x Days	Dollars	Dollar x Days
<b>Includable Expenses</b>							
<b>Fuel Expenses</b>							
1 Coal & Rail Transport	24.78	367,060	9,095,753	21,579	534,739	345,481	8,561,014
2 Gas for Generation	41.90	139,412	5,841,374	8,196	343,414	131,216	5,497,960
3 Oil	14.13	7,092	100,215	417	5,892	6,675	94,324
4 Nuclear & EOL	0.00	80,062	0	4,707	0	75,355	0
5 Nuclear Disposal	76.38	12,473	952,688	721	55,070	11,752	897,618
6		606,100	15,990,030	35,620	939,115	570,480	15,050,915
<b>Purchased Power</b>							
7 Purchases	24.62	989,971	24,373,094	57,960	1,426,977	932,011	22,946,117
8 Interchange	38.21	103,226	3,944,260	5,921	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	2,945,961	683	174,224	10,864	2,771,736
11 Pension & Benefits	28.34	41,928	1,188,248	2,613	74,046	39,316	1,114,202
12 Subtotal Labor & Related		298,285	7,272,670	18,059	437,528	280,227	6,835,142
14 All Other Operating Expenses	42.34	582,448	23,814,050	30,140	1,276,143	532,308	22,537,907
15 Property Tax	353.01	105,494	37,240,437	5,763	2,034,397	99,731	35,206,040
16 Employer's Payroll Taxes	26.83	21,401	574,197	1,310	35,149	20,091	539,045
17 Gross Earnings Tax	55.01	39,086	2,150,121	2,081	114,476	37,005	2,035,645
18 Federal Income Tax	36.50	67,543	2,465,311	530	19,363	67,012	2,445,948
19 State Income Tax	36.50	19,060	695,705	106	3,851	18,955	691,854
20 State Sales Tax Customer Billings	51.86	110,642	5,737,894	0	0	110,642	5,737,894
21 Total Expenses	42.51	2,923,257	124,257,756	157,560	6,515,901	42.57	2,765,697
22 Net Annual Expense Amount			340,432		17,652		322,580
<b>Revenues</b>	<b>Lag Days</b>	<b>Dollars</b>	<b>Dollar x Days</b>	<b>Dollars</b>	<b>Dollar x Days</b>	<b>Dollars</b>	<b>Dollar x Days</b>
23 Computer Billing 100.00%	45.45	2,879,484	130,872,548	149,550	6,797,048	2,729,934	124,075,500
24 Hand Billed 0.00%	45.45	0	0	0	0	0	0
25 Retail Revenue Adjustments	45.45	(2,371)	(107,762)	(1,939)	(83,583)	(532)	(24,179)
26 Interdepartmental	0.00	434	0	0	0	434	0
27 Late Payment	0.00	7,252	0	245	0	7,007	0
28 Connect and Trouble Charges	45.45	2,217	100,763	173	7,863	2,044	92,900
29 CIP Incentive	0.00	0	0	0	0	0	0
30 Rentals	34.28	4,630	158,716	251	8,604	4,379	150,112
31 Interchange Revenues	38.21	388,380	14,840,000	22,648	865,380	365,732	13,974,620
32 Sales for Resale	39.63	255,111	10,110,049	12,380	490,619	242,731	9,619,430
33 Production Associated Revenues	39.63	6,382	252,919	375	14,661	6,007	238,057
34 MISO	39.63	36,782	1,456,878	2,125	84,214	34,637	1,372,664
35 Point to Point Firm	39.63	4,680	185,468	271	10,740	4,409	174,729
36 Services & Facilities	39.63	8,621	341,650	493	19,538	8,128	322,113
37 Ancillary	39.63	6,223	245,617	360	14,267	5,863	232,351
38 Distribution Associated Revenues	45.45	1,986	90,264	0	0	1,986	90,264
39 Other	45.45	5,367	243,930	320	14,544	5,047	229,386
40 JOA - Rev frto PSC	39.63	(1,980)	(78,467)	(116)	(4,597)	(1,864)	(73,870)
41 (blank)	0.00	0	0	0	0	0	0
42 (blank)	0.00	0	0	0	0	0	0
43 (blank)	0.00	0	0	0	0	0	0
44 Total Revenues	44.05	3,603,178	158,713,573	187,236	8,239,498	44.05	3,415,942
45 Net Annual Amount			434,832		22,574		412,258
46 Expense / Revenue Factor			0.81129951		0.841503833		
47 Allocated Revenue Amount			352,779		18,996		
48 Net Cash Working Capital	Page 1 - Line 6		12,347		1,144		11,202

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

Case No. PU-07-776  
Exhibit \_\_\_ (AEH-2)  
Schedule 8, Page 1 of 5

<u>Line</u>	<u>Description</u>	<u>Initial Petition</u>	<u>Company Rebuttal Position</u>	<u>Corrected Staff Adjusted</u>
1	Average Rate Base	\$ 242,100	\$ 242,108	\$ 243,917
2	Operating Income (Before AFUDC)	\$ 9,794	\$ 10,399	\$ 15,167
3	Allowance for Funds Used During Construction	\$ -	\$ -	\$ -
4	Total Available for Return (Line 2 + Line 3 + Rounding)	\$ 9,794	\$ 10,399	\$ 15,167
5	Overall Rate of Return (Line 4 / Line 1)	4.05%	4.30%	6.22%
6	Required Rate of Return	9.20%	8.80%	8.80%
7	Operating Income Requirement (Line 1 x Line 6)	\$ 22,273	\$ 21,306	\$ 21,465
8	Income Deficiency (Line 7 - Line 6)	\$ 12,479	\$ 10,906	\$ 6,298
9	Gross Revenue Conversion Factor	1.64555	1.64555	1.64555
10	Revenue Deficiency (Line 8 x Line 9)	\$ 20,535	\$ 17,946	\$ 10,363
11	King Revenue Req. Adjustments			\$ (770) 1/
12	Net Deficiency before AS King & High Bridge			\$ 9,593
13	AS King revenue Requirement Adjustment (see Exhibit ___(AEH-2), Schedule 3			\$ (3,363)
14	High Bridge Revenue Requirement Adjustment (see Exhibit ___(AEH-2), Schedule 3			\$ (1,548)
15	Estimated Staff Recommended Deficiency (as corrected)			<b>\$ 4,683</b>
16	Retail Related Revenue Under Present Rates	\$ 147,179	\$ 147,711	\$ 147,711
17	Percentage Increase Needed in Overall Revenue (Deficiency/Revenues)	13.95%	12.15%	3.17%
1/	Remove Mercury Emissions Cost (corrected)	\$ (438)		
	Remove Refuse Derived Energy	(173)		
	Remove 25% Grand Meadow	(79)		
	Remove 25% Transmission to Wind Farms	(80)		
	Total	\$ (770)		

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 Recalculated Staff Position  
 (\$000's)

Case No. PU-07-776  
 Exhibit \_\_\_\_ (AEH-2)  
 Schedule 8, Page 2 of 5

Line No.	Description	Initial Petition Rate Base (A)	Reverse Pole Inspection & Replacement Program RB-1	Reverse Cable Replacement Program RB-2	Charge Pole & Cable Replacements to Acc. Dep. RB-3	Adjust Cash Working Capital RB-4	King's Depreciation Rate Adjustment RB-7	Amortize Cost of Removal Over 10 years RB-8	Corrected Staff Adjusted
Electric Plant as Booked									
1	Production	\$356,704							\$356,704
2	Transmission	\$87,557							\$87,557
3	Distribution	\$124,202	(\$92)	(\$250)	\$0			\$0	\$123,860
4	General	\$14,538							\$14,538
5	Common	\$24,338							\$24,338
6	TBT Investment	\$0							\$0
7	TOTAL Utility Plant in Service	\$607,339	(\$92)	(\$250)	\$0	\$0	\$0	\$0	\$606,997
Reserve for Depreciation									
8	Production	\$234,339					(\$1,830)	(\$919)	\$231,591
9	Transmission	\$29,941					(\$37)		\$29,904
10	Distribution	\$48,239	(\$2)	(\$3)	(\$342)		(\$191)		\$47,701
11	General	\$6,955							\$6,955
12	Common	\$13,692							\$13,692
13	TOTAL Reserve for Depreciation	\$333,166	(\$2)	(\$3)	(\$342)	\$0	(\$2,058)	(\$919)	\$329,843
Net Utility Plant in Service									
14	Production	\$122,365	\$0	\$0	\$0	\$0	\$1,830	\$919	\$125,113
15	Transmission	\$57,616	\$0	\$0	\$0	\$0	\$37	\$0	\$57,653
16	Distribution	\$75,964	(\$91)	(\$247)	\$342	\$0	\$191	\$0	\$76,159
17	General	\$7,583	\$0	\$0	\$0	\$0	\$0	\$0	\$7,583
18	Common	\$10,646	\$0	\$0	\$0	\$0	\$0	\$0	\$10,646
19	TBT Investment	\$0							\$0
20	Net Utility Plant in Service	\$274,173	(\$91)	(\$247)	\$342	\$0	\$2,058	\$919	\$277,154
21	Utility Plant Held for Future Use	\$0							\$0
22	Construction Work in Progress	\$4,802							\$4,802
23	Less: Accumulated Deferred Income Taxes	\$40,717	(\$1)	(\$3)			\$807	\$360	\$41,881
24	Cash Working Capital	\$1,136							\$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	\$0	\$0	\$0	\$2,706
32	Total Average Rate Base	\$242,100	(\$90)	(\$244)	\$342	\$0	\$1,251	\$558	\$243,917

**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-07-776  
 Exhibit \_\_\_ (AEH-2)  
 Schedule 8, 3 of 5

Line No.	Description	Initial Petition Income Stmt	Settlement ROR Change OI-1	Reverse Asset Based Trading- Ratepayer sharing OI-2	Reverse Asset Based Trading- Shareholder sharing OI-3	Reverse Non- Asset Based Trading- Ratepayer sharing OI-4	Reverse Non- Asset Based Trading- Shareholder sharing OI-5
<b><u>Operating Revenues</u></b>							
1	Retail	\$147,179		\$0		\$0	
2	CIP Revenue Adjustment	0					
3	Interdepartmental	0					
4	Other Operating	39,525			\$0		\$0
5	Gross Earnings Tax	0					
6	<b>Total Operating Revenues</b>	<b>\$186,704</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>
<b><u>Expenses</u></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>\$148,726</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</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	214	0	0	0	0	0
22	Payroll & Other	1,310					
23	<b>Total Taxes</b>	<b>\$9,025</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>
24	<b>Total Expenses</b>	<b>\$176,910</b>	<b>(\$1)</b>	<b>(\$1)</b>	<b>(\$1)</b>	<b>(\$1)</b>	<b>(\$1)</b>
25	Allowance for Funds Used During Construction	\$0					
26	<b>Total Operating Income</b>	<b>\$9,794</b>	<b>\$1</b>	<b>\$1</b>	<b>\$1</b>	<b>\$1</b>	<b>\$1</b>

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

Case No. PU-07-776  
Exhibit \_\_\_ (AEH-2)  
Schedule 8, 4 of 5

Line No.	Description	Reverse MISO Sch 16 & 17 Margin Adj OI-6	Charitable Contributions OI-7	RDF Amortization OI-8	Private Fuel Storage OI-9	Normalize Nuclear Refueling Costs OI-10	Charge Pole & Cable Replacement Programs to Non-legal OI-11
<b>Operating Revenues</b>							
1	Retail	\$532					
2	CIP Revenue Adjustment						
3	Interdepartmental						
4	Other Operating						
5	Gross Earnings Tax						
6	<b>Total Operating Revenues</b>	<b>\$532</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					(\$1,680)	
8	Power Production						
9	Transmission						
10	Distribution						(117)
11	Customer Accounting						
12	Customer Service & Information						
13	Sales, Econ Dvlp & Other						
14	Administrative & General		(86)				
15	Amortization			(170)	(190)		
16	<b>Total Operating Expenses</b>	<b>\$0</b>	<b>(\$86)</b>	<b>(\$170)</b>	<b>(\$190)</b>	<b>(\$1,680)</b>	<b>(\$117)</b>
17	Depreciation						(\$9)
Taxes:							
18	Property						
19	Gross Earnings						
20	Deferred Income Tax & ITC						(7)
21	Federal & State Income Tax	209	34	67	75	659	36
22	Payroll & Other						
23	<b>Total Taxes</b>	<b>\$209</b>	<b>\$34</b>	<b>\$67</b>	<b>\$75</b>	<b>\$659</b>	<b>\$29</b>
24	<b>Total Expenses</b>	<b>\$208</b>	<b>(\$53)</b>	<b>(\$104)</b>	<b>(\$116)</b>	<b>(\$1,021)</b>	<b>(\$98)</b>
25	Allowance for Funds Used During Construction						
26	<b>Total Operating Income</b>	<b>\$324</b>	<b>\$53</b>	<b>\$104</b>	<b>\$116</b>	<b>\$1,021</b>	<b>\$98</b>

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

Case No. PU-07-776  
 Exhibit \_\_\_\_ (AEH-2)  
 Schedule 8, 5 of 5

Line No.	Description	Reduce Executive Compensation OI-12	King Depreciation Rates OI-13	Amortize Cost of Removal Reg. Liab. over 10 years 1/ OI-14	CWC 15	Corrected Staff Adjusted
<b><u>Operating Revenues</u></b>						
1	Retail					\$147,711
2	CIP Revenue Adjustment					\$0
3	Interdepartmental					\$0
4	Other Operating					\$39,525
5	Gross Earnings Tax					0
6	<b>Total Operating Revenues</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$187,236</b>
<b><u>Expenses</u></b>						
Operating Expenses:						
7	Fuel & Purchased Energy					\$77,335
8	Power Production					\$40,491
9	Transmission					\$7,992
10	Distribution					\$5,538
11	Customer Accounting					\$4,343
12	Customer Service & Information					\$369
13	Sales, Econ Dvlp & Other					\$2
14	Administrative & General	(34)				\$10,279
15	Amortization			0		100
16	<b>Total Operating Expenses</b>	<b>(\$34)</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$146,449</b>
17	Depreciation		(\$4,115)	(\$1,837)		\$13,199
Taxes:						
18	Property					\$5,763
19	Gross Earnings					\$0
20	Deferred Income Tax & ITC		1,614	721		\$4,066
21	Federal & State Income Tax	13	(16)	(7)	0	\$1,283
22	Payroll & Other					1,310
23	<b>Total Taxes</b>	<b>\$13</b>	<b>\$1,598</b>	<b>\$714</b>	<b>\$0</b>	<b>\$12,422</b>
24	<b>Total Expenses</b>	<b>(\$21)</b>	<b>(\$2,517)</b>	<b>(\$1,124)</b>	<b>(\$1)</b>	<b>\$172,069</b>
25	Allowance for Funds Used During Construction	\$0		\$0	\$0	\$0
26	<b>Total Operating Income</b>	<b>\$21</b>	<b>\$2,517</b>	<b>\$1,124</b>	<b>\$1</b>	<b>\$15,167</b>

**A S King Plant Chemical Cost Adjustment**

	Jurisdictional Amounts				
AS King Plant Chemical Costs for 2008 Budget	5,273,600				
Wisconsin Interchange Agreement Revenue Portion	(820,662)	(715,144)	(47,451)	(42,335)	(15,732)
Reflect in Expense Wisconsin Company Expense recovered through the Interchange Agreement	820,662	715,144	47,451	42,335	15,732
Jurisdictional Allocation of Non-Minnesota Expense	497,738	-	223,829	199,700	74,210
<b>Total Test Year Amount to Reflect MN Deferral (25%)</b>	<b>1,318,400</b>	<b>715,144</b>	<b>271,279</b>	<b>242,035</b>	<b>89,942</b>
<b>Amount Reflected in Test Year Data</b>	<b>1,318,400</b>	<b>-</b>	<b>592,873</b>	<b>528,962</b>	<b>196,565</b>
<b>Adjustment to Expense</b>	<b>-</b>	<b>715,144</b>	<b>(321,594)</b>	<b>(286,927)</b>	<b>(106,623)</b>

**Xcel Energy**  
**2008 Budget Allocations**

		<u>2008 Budget</u>	
Customers (Electric)			
	<b>MN</b>	88.0585%	
	<b>ND</b>	6.2241%	
	<b>SD</b>	5.7164%	
	<b>WHL</b>	<u>0.0010%</u>	
		100.0000%	
Customers (Gas)			
	<b>MN</b>	90.6021%	
	<b>ND</b>	<u>9.3979%</u>	
		100.0000%	
Electric E10 (Energy)			
	<b>MN</b>	86.8696%	
	<b>ND</b>	5.8790%	
	<b>SD</b>	5.0980%	
	<b>WHL</b>	<u>2.1534%</u>	
		100.0000%	
Electric D10 (Demand)			
	<b>MN</b>	87.1423%	
	<b>ND</b>	5.7820%	44.97%
	<b>SD</b>	5.1587%	40.12%
	<b>WHL</b>	<u>1.9170%</u>	14.91%
		100.0000%	12.8577%
36 mth Demand Allocator			
	<b>MN</b>	84.4383%	
	<b>WI</b>	<u>15.5617%</u>	
		100.0000%	
Gas D10 (Design Day)			
	<b>MN</b>	88.7867%	
	<b>ND</b>	<u>11.2133%</u>	
		100.0000%	
Gas D11 (Load Dispatch)			
	<b>MN</b>	89.0260%	
	<b>ND</b>	<u>10.9740%</u>	
		100.0000%	