



**BEFORE THE NORTH DAKOTA  
PUBLIC SERVICE COMMISSION  
STATE OF NORTH DAKOTA**

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES  
POWER COMPANY FOR AUTHORITY TO INCREASE RATES FOR  
ELECTRIC SERVICE IN NORTH DAKOTA

CASE NO. PU-12-813

REVISED DIRECT TESTIMONY OF

DANTE MUGRACE

ON BEHALF OF THE ADVOCACY STAFF OF THE  
NORTH DAKOTA PUBLIC SERVICE COMMISSION

*Corrected in hearing*

**Dante Mugrace**

7/17/2013/22/2013

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hearing

Public Service Commission

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## **Appendix and Exhibits**

### **Schedules DM-1 through DM-28**



1       **I. STATEMENT OF QUALIFICATIONS**

2       **Q. Please state your name, position and business address.**

3       A. My name is Dante Mugrace. I am a Senior Consultant with the economic firm of  
4       Snavelly King Majoros & Associates, Inc. (Snavelly King) My business address is  
5       8100 Professional Place, Suite 306, Landover, Maryland 20785. In my capacity as a  
6       Senior Consultant, I am responsible for analyzing rate case filings, preparing expert  
7       testimony and evaluating revenue requirement proposals, economic and policy issues  
8       and methodologies used to set rates for utility services.

9  
10       **Q. Please describe Snavelly King.**

11       A. Snavelly- King was founded in 1970 to conduct research and consult on the rates,  
12       revenues, costs and economic performance of regulated firms and industries. Most of  
13       its work involves the development, preparation and presentation of expert witness  
14       testimony before federal and state regulatory agencies. Over the course of its 30+  
15       year's history, members of the firm have participated in hundreds of proceedings  
16       before almost all of the state commissions and all Federal commissions that regulate  
17       utilities or transportation industries.

18  
19       **Q. Please summarize your professional experience in the utility industry.**

20       A. Prior to my association with Snavelly King, I was employed by the New Jersey Board  
21       of Public Utilities Commission (NJBPU) from October 1983 to my retiring in June  
22       2011. I have held various positions throughout my tenure with the NJBPU beginning  
23       with various Accountant positions, and being promoted to Supervising Rate Analyst,

1 Administrative Analyst and finally with my last position as Bureau Chief of Rates in  
2 the Water Division. I held this last position for nearly 10 years. In my capacity as  
3 Bureau Chief, I was responsible for overseeing all rate filings and rate related  
4 applications filed with the NJBPU. I oversaw a staff of 12 on a daily basis with regard  
5 to the administrative, financial and managerial functions of the Bureau and the  
6 Division. My primary duties were to ensure that utilities had sufficient revenues to  
7 cover operating expenses, earn a reasonable return on investments and to ensure  
8 utilities provided safe, adequate and proper utility service at reasonable rates.

9  
10 **Q. Have you prepared a summary of your qualifications and experience?**

11 A. Yes. Appendix A is a summary of my qualifications and experience.

12  
13 **Q. For whom are you appearing in this proceeding?**

14 A. I am appearing on behalf of the Advocacy Staff of the North Dakota Public Service  
15 Commission. (NDPSC).

16  
17 **Q. Have you previously testified in regulatory proceedings?**

18 A. Yes, I am currently engaged in the Consolidated Edison Company of New York  
19 proceeding, representing the Intervener, the County of Westchester in Case No. 13-E-  
20 0030 (Electric Rate Case) and Case No. 12-G-0031 (Gas Rate Case).

1     **Q.    What is your educational background?**

2     A.    I received a Master of Business Administration, with a concentration in Strategic  
3           Management from Pace University-Lubin School of Business in New York City, New  
4           York. I received a Master of Public Administration from Kean University in Union,  
5           New Jersey. I received a B.S. in Accounting from Saint Peter's University in Jersey  
6           City, New Jersey.

7

8     **II.    PURPOSE OF TESTIMONY**

9     **Q.    What is the purpose of your testimony?**

10    A.    The purpose of my testimony is to recommend the appropriate revenue requirement for  
11           Northern States Power Company (NSP or Company) for electric service in North  
12           Dakota. On December 18, 2012, NSP filed a rate application with the NDPS  
13           seeking a change in its electric revenue in the amount of \$16.9 million or 9.25%  
14           effective for service on and after January 17, 2013 based on a 2013 test year. The  
15           Company subsequently updated its revenue requirement proposal and offered  
16           corrections that reduced the North Dakota revenue requirement deficiency from its  
17           initial amount of \$16.9 million to \$16.020 million or about \$900,000. The Company  
18           also requested implementation of a Transmission Cost Recovery Tariff (TCR) which  
19           would allow the Company to recover the capital and operating costs of investments in  
20           new or modified electric transmission facilities not included in the 2013 test year.

21           Karl R. Pavlovic will be responding to this area of the rate application. Also included

1 in the petition was a request for interim rates in the amount of \$14.7 million or 8.05%,  
2 effective February 16, 2013, subject to refund, until final rates are placed into effect.<sup>1</sup>

3 The Company's position is that the rate increase is needed to recover the costs of  
4 additional investments in electric distribution, generation (nuclear and non-nuclear)  
5 and transmission infrastructure to ensure system safety and reliability, continue to  
6 provide high quality service to customers and support economic growth.

7 Snavelly King was engaged by the NDPSC Advocacy Staff to review the Company's  
8 filing and to provide recommendations regarding the Company's revenue requirement  
9 request. In developing my recommendations, I have relied upon the cost of capital  
10 structure testimony of Charles W. King, the depreciation and decommissioning  
11 testimony of Michael J. Majoros, and the jurisdictional allocation and rate design  
12 testimony of Karl R. Pavlovic.

13  
14 **Q. What are the most significant revenue requirement issues in this filing?**

15 A. The most significant revenue requirement issues in this filing are the Company's  
16 request for a cost of equity of 10.6% and the request for rate base inclusion of new  
17 plant in service of which nearly half is related to its nuclear operations. The Company  
18 claims that \$11.4 million or 67% of the requested \$16.9 million of the revenue  
19 deficiency is related to plant additions, and \$8.4 million of the \$11.4 million is related  
20 to the Company's nuclear operations. The Company is also claiming additional  
21 increases in its operational costs. Increases in the cost of materials such as  
22 transmission related materials and services such as the use of highly skilled labor for

---

<sup>1</sup> On February 16, 2013, the NDPSC approved the interim rate increase in the amount of \$14.7 million or 8.05%.

1 engineering, construction and maintenance services are also a reason for the  
2 Company's requested increase.  
3

4 **III. SUMMARY OF CONCLUSIONS**

5 **Q. What are your conclusions and recommendations regarding the Company's**  
6 **revenue requirement request in the amount of \$16.9 million or 9.25% increase?**

7 **A.** I have reached the following revenue requirement conclusions in this rate filing:

- 8 1. The twelve months ended December 31, 2013, is a reasonable test year to use in  
9 this case to evaluate the reasonableness of the Company's proposed revenue  
10 requirement increase.
- 11 2. The appropriate rate base level should be set at ~~\$322,514~~326,528,000 which is  
12 ~~\$49,150,000~~53,164,000 lower than the Company's claim of \$375,678,000.
- 13 3. The appropriate pro-forma operating revenues should be set to \$213,556,000 which  
14 is \$14,670,000 lower than the Company's claim of \$228,226,000.
- 15 4. The appropriate present rate pro-forma operating income is ~~\$29,472,000~~24,308,000  
16 which is ~~\$9,670,000~~4,506,000 higher than the Company's claim of \$19,802,000.
- 17 5. The appropriate overall rate of return on rate base, as recommended by Snively  
18 King Witness Charles King, is 7.138%, incorporating a recommended return on  
19 equity of 9.00%. This compares to the Company's proposed overall rate of return  
20 on rate base of 7.90%, including a requested return on equity of 10.60%.
- 21 6. The recommended ratemaking components as indicated above calculates to an overall  
22 revenue requirement decrease of ~~\$9,999,000~~2,088,000, which is

1 |        \$~~26,019,000~~~~18,108,000~~ lower than the Company's updated proposed revenue  
2 |        requirement increase of 16,020,000.

3 | **IV. RATE BASE ISSUES**

4 | **A. Utility Plant in Service**

5 | **Q. How did NSP determine its utility plant in service balance (UPIS) in this case?**

6 | A. NSP calculated its UPIS by beginning with its 12 months ending December 31, 2011,  
7 | historical balance as shown on Company Exhibit AEH-1, Schedule 3 page 2 of 6, which  
8 | indicates a year end average balance in the amount of \$742,545,000 for the North Dakota  
9 | jurisdiction. The Company then adjusted the calendar year end 2011 financial results  
10 | for known ratemaking adjustments deemed necessary, and included changes in costs to  
11 | provide a normalized level of rate base and expenses. The Company then budgeted  
12 | projections for 2012, and applied these projections to the March 31, 2012 balance to  
13 | arrive at a beginning test year balance. The Company's requested utility plant in service  
14 | balance for the test year 2013 was computed by applying the 2013 capital budget to the  
15 | beginning test year balance of \$742,545,000 adjusted for plant additions, retirements,  
16 | depreciation, salvage and removal costs projected to occur during the test year. The  
17 | Company calculated a level of Utility Plant in Service in the amount of \$870,972,000 or  
18 | \$128,427,000 higher than the 2011 historical period. The Company selected 2013 as the  
19 | test year because it represented the most recent available budget year and a reasonable  
20 | representation of the costs and expenses the Company would incur when interim and  
21 | final rates would become effective.

1 The Company updated its UPIS pursuant to data response, NDPSC-5-026, Supplemental,  
2 reducing its proposed UPIS from \$870,972,000 to \$869,185,000, a decrease of  
3 \$1,787,000.

4  
5 **Q. Do you believe that the base year (2011) and the proposed test year (2013) is a**  
6 **reasonable approach for the purposes of determining NSP's revenue requirement in**  
7 **this filing?**

8 A. Yes, the use of a projected test year is consistent with the North Dakota Century Code  
9 (N.D.C.C.) §49-5-04.1, subd. 1 which allows a utility to select a future test year.

10 The N.D.C.C. also provides for the utility to present the following information:

- 11 a. A comparison of forecast data to historical period data to demonstrate the  
12 reliability and accuracy of the utility's forecast including a comparison of the  
13 prior year's forecast or budgeted data to actual data for those periods.
- 14 b. A statement that the public utility's forecast is reasonable, reliable, and was made  
15 in good faith and that all basic assumptions used in making or supporting the  
16 forecast are reasonable, evaluated, identified, and justified to allow the  
17 Commission to test the appropriateness of the forecast.
- 18 c. A statement of the accounting treatment that has been applied to anticipated  
19 events and transactions in the forecast is the same as the accounting treatment to  
20 be applied in recording the events once they have occurred.

21 However, the NDCC requires the test year be based on the previous 12 months so  
22 until the 2012 earnings report was available, the Company was not in full  
23 compliance with the law.

1  
2 **Q. Please explain the approach that you have used to determine the Company's 2013**  
3 **Test Year plant in service balance in this case.**

4 A. I began my approach by reviewing the Company's 2011 and 2012 Earnings Reports filed  
5 with the NDPSC. The results are shown in the table below:

<u>Actual Plant in Service</u>	
<u>Based on Earnings Reports</u>	
(\$000)	
2012	\$ 780,660
2011	\$ 742,545
Difference	\$ 38,115

6 I then reviewed Data Request NDPSC-2-010 and NDPSC 5-20, which asked for plant  
7 additions affecting the 2013 test year revenue requirement. Attachments A to the data  
8 requests page 32 (NDPSC 2-10) and page 46 (NDPSC-5-20), shows total 2013 plant  
9 additions for NSPM in the amount of \$1,533,295,000. In Data Request NDPSC-5-086,  
10 Company Witness Foss indicated that the North Dakota demand allocator is 5.1121%.

11 I took the Company's total plant additions for 2013 of \$1,533,295,000 and multiplied that  
12 amount by the demand allocator of 5.1121% to arrive at the North Dakota Jurisdictional  
13 capital additions for 2013 in the amount of \$78,383,000.

14  
15 **Q. Are those the only additions the Company had proposed to include in this rate**  
16 **filing?**

17 A. No. According to Witness Heuer's response to data request NDPSC 2-010, these  
18 totals do not include the proposed test year adjustments, specifically the Bemidji  
19 CAPX2020 project in the amount of \$1,906,000, the Brookings CAPX2020 project in the  
20 amount of \$194,000 and the Nuclear Fuel Inventory update in the amount of \$243,000.

1           **1.     Bemidji CAPX2020**

2           **Q.   Please explain your recommendations with respect to the Bemidji CAPX2020 plant**  
3           **addition.**

4           A.   The Company included the Bemidji CAPX2020 transmission project in its plant in  
5           service balance to reflect the September 2012 in-service date for this project as reflected  
6           in the Company's Exhibit AEH-1, Schedule 5, page 1 of 1, Column 2 in the amount of  
7           \$1,906,000. The rate base impact for this project is computed to be an increase of  
8           \$1,160,000. This increases the test year revenue requirement in the amount of \$193,000  
9           as reflected in the Company's Exhibit AEH-1, Schedule 6, page 1 of 3, Column 2.

10  
11          **Q.   What is your recommendation regarding the Company's inclusion of the Bemidji**  
12          **CapX2020 Transmission Project?**

13          A.   I agree with the Company. My recommendation is shown on Schedule DM-4.

14  
15          **2.     Brookings CAPX2020**

16          **Q.   Please describe the Company's Brookings CapX2020 Transmission Project.**

17          A.   The Company is requesting to add \$194,000 to its utility plant in service for the  
18          Brookings CapX2020 Transmission Project. This is shown in Company Exhibit AEH-1,  
19          Schedule 5, page 1 of 1, Column 3. The average rate base impact for this project is  
20          computed to be an increase of \$171,000. This proposal increases the test year revenue  
21          requirement in the amount of \$22,000 as reflected in the Company's Exhibit AEH-1.  
22          Schedule 5, page 1 of 3, Column 3. From what I understand the Brookings Project is a  
23          Multi-Value Project(MVP).

1

2 **Q. What is your recommendation regarding the Brookings CapX2020 Transmission**  
3 **Project?**

4 A. I agree with the Company. My recommendation is shown on Schedule DM-4.

5

6 **3. Nuclear Fuel Inventory**

7 **Q. Please describe the Company's update to its Nuclear Fuel Inventory.**

8 A. The Company updated its Nuclear Fuel Inventory after the Summer 2012 sales forecast  
9 was completed and after the capital budget was finalized. The result of this update was  
10 an increase to its utility plant in service balance in the amount of \$243,000 as shown in  
11 Company Exhibit AEH-1, Schedule 5, page 1 of 1, Column 4. The rate base impact for  
12 the Nuclear Fuel Inventory is computed to be an increase of \$229,000. This proposal  
13 decreases test year revenue requirement in the amount of \$26,000. This is shown in the  
14 Company Exhibit AEH-1, Schedule 6, page 1 of 3, Column 4.

15

16 **Q. What is your recommendation regarding the Company's Nuclear Fuel Inventory**  
17 **Update?**

18 A. I agree with the Company. My recommendation is shown on Schedule DM-4.

19

20 **4. Supplemental Updates to UPIS Balance**

21 **Q. Did the Company update its UPIS in data request NDPSC 5-026, Supplemental?**

22 A. Yes. The Company included the following adjustments to its UPIS balance in its  
23 Supplement filing:

1	AFUDC Correction Discovery	\$ 132,000
2	AFUDC MISO Correction Discovery	\$ (3,000)
3	Monticello License Discovery	\$(1,337,000)
4	Projects out of 2013 Discovery	<u>\$ (579,000)</u>
5	Total	<u>\$(1,787,000)</u>

6 I have accepted the Company's Supplemental information regarding these 4 items.

7 Based upon the Company's updated data request, I've concluded that the 2013 test year  
 8 plant balance should be set at \$859,600,000 before any allocation factors that Advocacy  
 9 Staff Witness Pavlovic has included. Based upon Mr. Pavlovic's Allocation Factor of  
 10 87.10% pertaining to the Company's Transmission and Distribution Allocation (T&D) I  
 11 have reduced the amount of my recommended Plant in Service Balance of \$859,044,000  
 12 by 87.10% to arrive at a recommended Plant in Service Balance of \$748,227,000.

13 The Allocation Factor of 87.10% will be discussed in Mr. Pavlovic's testimony.

14 **Q. Can you please summarize your recommended plant additions and plant balance**  
 15 **for the test year 2013?**

16 **A.** Yes, my summary is as listed below:

17

18	Plant Balance as of December 31, 2012	\$780,660,000
19	Plant Additions through December 31, 2013	<u>78,384,000</u>
20	Subtotal	\$859,044,000
21	Allocation Factor	87.10%
22	Recommended Beginning Balance	\$748,227,000
23	Bemidji CAPX2020	1,906,000
24	Brookings CAPX2020	194,000
25	Nuclear Fuel Updates	243,000
26	Supplemental UPIS updates:	<u>(1,787,000)</u>
27	Total	<u>\$748,783,000</u>

28 This amount is \$120,402,000 less than the Company adjusted claim of \$869,185,000.

29 My recommended balance is shown on Schedule DM-3 and 4.

1

2 **B. Construction Work In Progress**3 **Q. What has the Company included in its calculation of Rate Base with respect to**  
4 **Construction Work in Progress (CWIP)?**5 A. The Company has included \$2,037,000 of CWIP in its calculation of Rate Base. This is  
6 shown on the Company's Exhibit AEH-1, Schedule 8, page 2 of 6.

7

8 **Q. What is the Company's justification for including CWIP in its Rate Base**  
9 **calculation?**10 A. The Company has indicated that the only CWIP it has included in its calculation of Rate  
11 Base are costs that are related to projects of a short duration that do not accrue Allowance  
12 for Funds used During Construction (AFUDC). The Company claims that there is no  
13 AFUDC offset added to operating income.

14

15 **Q. How did the Company calculate the \$2,037,000 CWIP rate base amount in its filing?**16 A. The Company calculated the CWIP amount of \$2,037,000 by a simple average of  
17 projected short term CWIP beginning and ending test year balances, which is what they  
18 claimed was used in its last NDPSC rate case and is consistent with the Company's  
19 calculation of average rate base.

20

21 **Q. Do you have a recommendation regarding this item?**22 A. I have used Advocacy Staff Witness Pavlovic's Allocation Factor of 84.8% to compute  
23 my recommended level of CWIP to be included in Plant in Service. Using the Company's

1 beginning balance of \$2,037,000 and calculating 84.80% I compute a CWIP balance of  
2 \$1,727,000. My recommendation is shown on Schedule DM-6. The allocation factor of  
3 84.80% will be discussed in Mr. Pavlovic's testimony.

4  
5 **C. Depreciation Reserve Balance**

6 **Q. Please explain how the Company calculated its Depreciation Reserve balance in the**  
7 **updated amount of \$419,306,000 as shown on Exhibit AEH-1, Schedule 5, page 1 of**  
8 **1, updated as of June 6, 2013.**

9 A. The Company started out with its ending average balance in the Depreciation Reserve in  
10 the amount of \$364,662,000 for the year ended December 31, 2011, as shown on Exhibit  
11 AEH-1 Schedule 3, page 2 of 6. To that balance the Company added its budget  
12 projections to arrive at a test year Depreciation Reserve balance at year end 2012. The  
13 Company then applied its budget projections to the beginning Depreciation Reserve  
14 balance that it projected to occur during the test year to arrive at the year-end  
15 Depreciation Reserve of \$419,306,000.

16  
17 **Q. What is your recommendation with respect to the level of Depreciation Reserve for**  
18 **the test year ending December 31, 2013?**

19 A. I reviewed the Company's Average 2011 Depreciation Reserve Balance in Company  
20 Exhibit AEH-1, Schedule 3, page 2 of 6, showing an amount of \$364,662,000. I have  
21 also reviewed the Company's updated Proposed 2013 test year Depreciation Reserve  
22 balance in the amount of \$419,306,000 as shown on Exhibit AEH-1, Schedule 5, page 1  
23 of 1, updated as of June 6, 2013. The below additions to the Company's proposed

1 Depreciation Reserve are in addition to the Company's Beginning Balance of

2 Accumulated Depreciation:

		(\$000's)
3		
4	Beginning Balance	\$418,885
5	1. Bemidji CAPX2020	\$ 40
6	2. Brookings CAPX2020	\$ (3)
7	3. Nuclear Fuel Inventory Update	\$ 25
8	4. 2012 Depreciation Study (various)	\$ 521
9	5. Production Remaining Life	\$ (127)
10	6. Black Dog Removal/Remediation	\$ 0
11	7. AFUDC Correction Discovery	\$ 3
12	8. Monticello License Discovery	\$ (26)
13	9. Projects out of 2013 Discovery	\$ (2)
14	10. Sherco 3 Discovery	<u>\$ (11)</u>
15	Total proposed Depreciation Reserve	<u>\$ 419,306</u>

16 I computed my recommended Depreciation Reserve Balance by taking the average  
 17 beginning and ending balances (\$418,885,000 + \$419,306,000/2) and divided that by the  
 18 Company's proposed average plant in service balance of \$869,185,000 to arrive at  
 19 48.22%. I then used the 48.22% and multiplied it by my recommended plant in service  
 20 balance of \$859,044,000 and computed a Depreciation Reserve Balance of \$414,231.

21 Based upon the recommendation of Advocacy Staff Witness Pavlovic I have calculated  
 22 the Company's Accumulated Depreciation Reserve balance by using Mr. Pavlovic's  
 23 87.20% Allocation Factor and by the my recommended beginning Depreciation Reserve  
 24 Bbalance of \$418,885,000 \$414,231,000 to derive at a beginning balance of \$361,209,000  
 25 before adjustments. 365,268,000. I then accepted and included the Company's proposed  
 26 adjustments as shown above to derive at a total proposed Accumulated Depreciation  
 27 Reserve balance of \$361,630,000 365,689,000 My recommendation is shown on Revised  
 28 Schedule DM-5.

1 The allocation factor of 87.20% will be discussed in Mr. Pavlovic's testimony.

2  
3 **D. Accumulated Deferred Income Taxes**

4 **Q. Please explain the Company's computation of its Accumulated Deferred Income**  
5 **Tax Balance (ADIT) for the 2013 test year in the amount of \$92,784,000 as shown on**  
6 **Exhibit AEH-1, Schedule 5, and its updated amount of \$92,805,000 as shown on**  
7 **Exhibit AEH-1, Schedule 8, Updated, page 2 of 6.**

8 A. The Company calculated the ADIT balance in the amount of \$92,805,000 by simply  
9 averaging the beginning and projected ending test year ADIT balances.

10  
11 **Q. Do you have any recommendation regarding the ADIT balance in the amount of**  
12 **\$92,805,000?**

13 A. Yes. I recommend an average ADIT balance for the end of the 2013 in the amount of  
14 \$79,072,000.

15  
16 **Q. How did you derive the average ADIT balance in the amount of \$90,774,000?**

17 A. I began with the Company's proposed ADIT Balance as of December 31, 2013,  
18 unadjusted in the amount of \$90,835,000. I then used Advocacy Staff's Witness Pavlovic  
19 allocation factor of 87.10% to derive at a beginning balance of \$79,117,000. I then added  
20 the Company's adjustments as shown on Exhibit AEH-1, Schedule 5, page 1 of 1 to  
21 compute a ADIT balance of \$81,087,000. Since the Company used an average of the  
22 beginning and ending test year balances to compute its proposed ADIT balance, I used an  
23 average percentage of the Company's beginning UPIS and ADIT balance which

1 calculates to 10.45% ( $\$90,835/\$868,630$ ) and the average percentage of the Company's  
2 ending UPIS and ADIT balance which calculates to 10.67% ( $\$92,805/\$869,185$ ). The  
3 average of the two is 10.56%. Using my recommended UPIS balance of  $\$748,783,000$   
4 and multiplying that balance by 10.56%, I arrived at my recommended ADIT balance of  
5  $\$79,072,000$ .

6 My recommendation is shown on Schedule DM-7. The allocation factor of 87.10% will  
7 be discussed in Mr. Pavlovic's testimony.

8  
9 **E. Cash Working Capital**

10 **Q. Please describe the Company's Cash Working Capital proposal.**

11 A. The Company's Cash Working Capital (CWC) allowance is ( $\$926,000$ ). The calculation  
12 is shown on Company Exhibit AEH-1, Schedule 8 page 2 of 6. The Company updated  
13 this amount in its June 6, 2013 Schedules to ( $\$1,080,000$ ) The CWC was calculated by  
14 applying the results of a comprehensive lead/lag study to the projected test year revenues  
15 and expenses. The Company stated that the components of the test year CWC have been  
16 calculated consistent with the methods used in the most recent North Dakota rate case.  
17 The negative CWC indicates overall revenue collections occurred sooner than the date  
18 when the associated costs of services are paid. The negative CWC reduces Rate Base to  
19 compensate customers for funds provided to meet CWC requirements.

20  
21 **Q. What is your recommendation regarding the Company's Updated calculation of a**  
22 **( $\$1,080,000$ ) CWC?**

1 A. I do not have any changes to the formula or other components that the Company used to  
2 create and to calculate the CWC. However, I made several adjustments to the Company  
3 CWC calculations which correspond to my adjustments related to the Company's  
4 Revenues, O & M Expenses and Taxes. With those adjustments, my CWC allowance is  
5 computed at \$~~(928,000)~~<sup>2</sup>~~883,000~~. My recommendations are shown on Revised Schedule  
6 DM-8, and Schedule DM-Attachment.

7  
8 **F. Materials and Supplies**

9 **Q. Please describe how the Company calculated its Materials and Supplies.**

10 A. The Company calculated its Materials and Supplies amount of \$7,613,000 by using a 13  
11 month average balance of the account projected during the test year.

12  
13 **Q. What is your recommendation regarding the Company's calculation of its Materials  
14 and Supplies balance?**

15 A. I agree with the Company's proposed Materials and Supplies balance of \$7,613,000.  
16 My recommendation is shown on Schedule DM-9.

17  
18 **G. Fuel Inventory**

19 **Q. Please describe how the Company calculated its Fuel Inventory.**

20 A. The Company calculated its Fuel Inventory amount of \$5,899,000 the same way it  
21 calculated its Materials and Supplies balance; by the use of a 13 month average balance  
22 of the account projected during the test year.

---

<sup>2</sup>~~Due to the change in the Federal Income and State Income Tax with respect to my change in  
Depreciation Expense, the correct CWC is (881,000), however, this does not change my recommended  
revenue requirement.~~

1 My recommendation is shown on Schedule DM-9.

2

3

4 **H. Non-Plant Assets and Liabilities**

5 **Q. Please describe how the Company calculated its Non-Plant Assets and Liabilities.**

6 A. The balance of (\$1,809,000) in Non-Plant Assets and Liabilities represents the 2013  
7 estimates of these balances. The book/tax timing differences associated with these items  
8 have been reflected in the determination of current and deferred income tax provision and  
9 Accumulated Deferred Income Tax balances as discussed previously in my testimony.  
10 The amount of (\$1,809,000) is primarily composed of liabilities. The negative balance  
11 reduces the Company's rate base. In its updated June 6, 2013 exhibits, the Company  
12 adjusted its Non-Plant Assets and Liabilities to (\$2,100,000), as shown on Exhibit AEH-  
13 1, Schedule 5, page 1 of 1, Column 10, line 25.

14

15 **Q. What is your recommendation regarding the Company's calculation of Non-Plant  
16 Assets and Liabilities?**

17 A. I agree with the Company's balance of Non-Plant Assets and Liabilities in the amount of  
18 (\$2,100,000).

19 My recommendation is shown on Schedule DM-9.

20

21 **I. Other Rate Base Items**

22 **Q. Please describe the Company's other Rate Base Items.**

1 A. The Company's Other Rate Base Items are comprised of Prepayments, Nuclear Outage  
2 Amortization, Customer Advances, Customer Deposits and Other Working Capital. I will  
3 address each item below.

4

5 **1. Prepayments**

6 A. The Company calculated Prepayments in the amount of \$1,050,000 using a 13 month  
7 average balance during the period ended May 31, 2012, as a proxy for the test year.  
8 Company Exhibit AEH-1, Schedule 15, page 1 of 3 shows this amount.

9

10 **Q. What is your recommendation regarding the Company's calculation of**  
11 **Prepayments in the amount of \$1,050,000?**

12 A. I agree with the Company's balance of its Prepayments in the amount of \$1,050,000.  
13 My recommendation is shown on Schedule DM-9, Footnote 1.

14

15 **2. Nuclear Outage Amortization**

16 **Q. Please describe how the Company calculated its Nuclear Outage Amortization.**

17 A. The Company calculated its Nuclear Outage Amortization in the amount of \$5,018,000  
18 by reflecting an increase in the cost of the Fall of 2012 Prairie Island Unit 1 refueling  
19 outage. The Company claimed that because these additional costs were incurred in 2012,  
20 deferred to the balance sheet, and then amortized over the useful life of the outage, it was  
21 necessary to update the amortization included in the O & M Budget. The change in the  
22 cost of the outage has been reflected in the 2013 beginning of year and end of year rate  
23 base balances. Company Exhibit AEH-1, Schedule 15, page 1 of 3 shows this amount.

1

2 **Q. What is your recommendation regarding the Company's calculation of its level of**  
3 **Nuclear Outage Amortization in the amount of \$5,018,000?**

4 A. I agree with the Company's balance of its Nuclear Outage Amortization in the amount of  
5 \$5,018,000. My recommendation is shown on Schedule DM-9.

6

7 **3. Customer Advances**

8 **Q. Please describe how the Company calculated its Customer Advances.**

9 A. The Company calculated Customer Advances in the amount of (\$18,000) by using an  
10 actual 13 month average month balance during the period ended May 12, 2012 as a proxy  
11 for the test year. Company Exhibit AEH-1, Schedule 15, page 1 of 3 shows this amount.

12

13 **Q. What is your recommendation regarding the Company's calculation of Customer**  
14 **Advances in the amount of (\$18,000)?**

15 A. I agree with the Company's Customer Advances balance in the amount of (\$18,000). My  
16 recommendation is shown on Schedule DM-9, Footnote 1.

17

18 **4. Customer Deposits**

19 **Q. Please describe how the Company calculated Customer Deposits.**

20 A. The Company calculated Customer Deposits in the amount of (\$213,000) by using an  
21 actual 13 month average month balance for the period ending May 12, 2012 as a proxy  
22 for the test year. Company Exhibit AEH-1, Schedule 15, page 1 of 3 shows this amount.

23

1 **Q. What is your recommendation regarding the Company's calculation of its level of**  
 2 **Customer Deposits in the amount of (\$213,000)?**

3 A. I agree with the Company's Customers Deposits amount of (\$213,000). My  
 4 recommendation is shown on Schedule DM-9, Footnote 1.

5

6 **5. Other Working Capital**

7 **Q. How has the Company computed its Other Working Capital Allowance?**

8 A. The Company computed its Other Working Capital Allowance by using the average 13  
 9 month balance for the period ending May 12, 2012, as a proxy for the test year. The  
 10 Company is proposing Other Working Capital in the amount of \$398,000.

11

12 **Q. What is your recommendation with respect to the Company's Other Working**  
 13 **Capital balance?**

14 A. I agree with the Company's balance of Other Working Capital level in the amount of  
 15 \$398,000.

16 My recommendation is shown on Schedule DM-9, Footnote 1.

17

18 **Q. Please summarize your recommendations with respect to the Company's Other**  
 19 **Rate Base Items balance.**

20 A. My summary is as below:

21	Prepayments	\$ 1,050,000
22	Nuclear Outage Amortization	\$ 5,018,000
23	Customer Advances	\$ (18,000)
24	Customer Deposits	\$ (213,000)
25	Other Working Capital	<u>\$ 398,000</u>
26	Total Other Rate Base Items	<u>\$ 6,235,000</u>

1

2

3 **J. Summary of Rate Base Issues**4 **Q. What is the impact of your rate base adjustments?**

5 A. My recommended adjustments reduce the Company's rate base from the proposed  
6 \$375,678,000, as reflected in the Company's updated Exhibit AEH-1, Schedule 5, page 1  
7 of 1, to \$326,528,000 ~~322,514,000~~, as summarized on Revised Schedule DM-3.

8

9 **V. COST OF CAPITAL**

10 **Q. What is your position regarding the Company's proposed Cost of Capital**  
11 **Structure?**

12 A. I am relying on the testimony of Advocacy Staff witness Charles King and have used the  
13 capital structure as shown on my Schedule DM-2 to develop my recommended revenue  
14 requirement increase.

15

16 **VI. INCOME STATEMENT**17 **A. Revenues**

18 **Q. What is the Company proposing with respect to Test Year Present Rate Revenues**  
19 **for the period ending December 31, 2013?**

20 A. The Company calculated unadjusted Test Year Present Rate Revenues in the amount of  
21 \$231,340,000 as shown in Company Exhibit AEH-1, Schedule 6, page 1 of 3, Column 1.  
22 This amount is comprised of Retail Operating Revenues in the amount of \$182,724,000  
23 and Other Operating Revenues in the amount of \$48,616,000. The Retail Operating

1 Revenues is composed of two components: Base Revenues in the amount of  
 2 \$120,805,000 and Fuel in the amount of \$61,919,000 (Company Work paper R2-1a). A  
 3 further breakdown of the Company's Retail Operating Revenues is shown on Company  
 4 Exhibit Notice, Schedule 2 page 1 of 1, and in Company Work paper R2-2.

5 The Company also adjusts its Other Operating Revenues by including the following:

6	a. Asset Margin Sharing	\$( 505,000) <sup>3</sup>
7	b. Non-Asset Margin Sharing	\$( 334,000)
8	c. Emission Credit Amortization	\$( 87,000)
9	d. MISO CWIP Revenue and Expense Adjustment	<u>\$(2,188,000)</u>

10	Total Adjustments to Other Operating Revenues	<u>\$(3,114,000)</u>
----	---	----------------------

11 By applying the Company's adjustments to Other Operating Revenues, the Company  
 12 calculated an adjusted Other Operating Revenue balance of (\$48,616,000 - \$3,114,000)  
 13 \$45,502,000. This is reflected in Company Exhibit AEH-1, Schedule 6, page 3 of 3,  
 14 Column entitled "Proposed 2013 Test Year."

15 With the adjustments to the Other Operating Revenues listed above, the total Test Year  
 16 Revenue at Present Rates ending December 31, 2013, is calculated by the Company to be  
 17 \$228,226,000. (Company Exhibit AEH-1, Schedule 6, page 3 of 3, Proposed 2013 Test  
 18 Year Column, and Company Exhibit AEH-1, Schedule 11, page 1 of 2, Column A).

19  
 20 **1. Retail Operating Revenues**

21 **Q. Did the Company propose any adjustments to its Retail Operating Revenues in the**  
 22 **amount of \$182,724,000?**

23 **A.** The Company did not propose any adjustments to its Retail Operating Revenues.  
 24

<sup>3</sup> These amounts are listed in Company Exhibit AEH-1, Schedule 6, page 2 of 3, Columns 18 and 19, and page 3 of 3, Columns 30 and 31 under Operating Revenues.

1 **Q. Do you have any recommendations with respect to the Company's Retail Operating**  
 2 **Revenues in the amount of \$182,724,000?**

3 A. Yes. I reviewed the Company's NDPSC 2010, 2011 and 2012 Earnings Reports,  
 4 specifically its Retail Operating Revenues and based upon the information contained I  
 5 computed the following: (\$000's)

6	<u>2010</u>	<u>2011</u>	<u>2012</u>
7	\$155,671	\$176,290	\$179,657
8			
9	Average		<b>\$170,539</b>

10 I also reviewed the Company's Mwh Sales for the same years, and computed the  
 11 following: (000's)

12	<u>2010</u>	<u>2011</u>	<u>2012</u>
13	2,206	2,243	2,207
14			
15	Average		<b>2,219</b>
16			

17 Finally I computed the average cost per Kwh for each of the years 2010, 2011 and 2012  
 18 and have computed the following: (in cents)

19	<u>2010</u>	<u>2011</u>	<u>2012</u>
20	7.06	7.86	8.13
21	Average Kwh price		<b>7.68</b>

22 I then reviewed and compared the Company's projected Mwh Sales as contained in  
 23 Company Exhibit (Notice) Schedule 2 page 1 of 1 which shows total projected Mwh  
 24 Sales for all customers in the amount of 2,270,721.

25  
 26 **Q. Did you review any other documentation with respect to the Company's projected**  
 27 **Retail Revenues?**

1 A. Yes. In Data Response NDPSC-5-071, the Company has indicated that as of the first  
2 quarter of 2013, Total Retail Mwh Sales amounted to 615,374, which was an increase of  
3 1.54% over the first quarter of 2012 in the amount of 606,038. Further the Company has  
4 indicated in Data Request NDPSC-5-039, Attachment A that as of the end of the first  
5 quarter of 2013, the Customer Count was 90,703, which is higher than what the Company  
6 had projected in its Notice of 89,985.

7  
8 **Q. What does this information provide regarding to the Company's Retail Operating**  
9 **Revenues?**

10 A. This analysis shows that the Company has increased its customer count by an additional  
11 718 (90,703-89,985). This analysis also shows that the Company's Mwh Sales has  
12 increased in the first quarter 2013 over its first quarter 2012 by 1.54%. Based upon this  
13 review, I am recommending increasing the Company's proposed Mwh Sales that it has  
14 projected in its Notice from 2,270,721 by 1.54% which is the actual increase in Mwh  
15 Sales from 1<sup>st</sup> quarter 2012 to 1<sup>st</sup> quarter 2013. I used the increase of 1.54% to compute  
16 the annual effect of the Company's initial Mwh Sales of 2,270,721 to arrive at known and  
17 measurable changes in its Mwh Sales that has actually occurred in 2013. My updated  
18 total Mwh Sales is therefore computed at (2,270,721 times 1.54%) 2,305,690.

19  
20 **Q. What else did you review to determine a proper level of Sales Revenues for the**  
21 **Company?**

22 A. I used the Company's three year average of Kwh costs that I computed above in the  
23 amount of 7.68 cents and multiplied that by my recommended level of projected Mwh

1 Sales of 2,305,690. This computes to a projected level of Sales Revenues of  
2 \$177,077,000.

3  
4 **Q. What have you concluded with respect to the Company's Retail Operating  
5 Revenues?**

6 A. As I indicated above, it is evident that the Company's Mwh Sales have increased from  
7 the Company's Initial projections as shown in its Notice. It is also evident that the  
8 Company customer count has increased from its projected level of 89,985 as shown in its  
9 Notice to what is contained in Data Request NDPSC-5-039 in the 1<sup>st</sup> quarter 2013 of  
10 90,703. By using most current data, a proper level of Sales Revenues is computed.  
11 Based upon the above, I recommend that the Company's Retail Operating Revenues be  
12 set in the amount of \$177,077,000. My recommendation is shown on Schedule DM-11.

13  
14 **2. Other Operating Revenues**

15 **Q. What is included in the Company's Other Operating Revenues in the amount of  
16 \$48,616,000 as calculated in Company Exhibit AEH-1, Schedule 6, page 1 of 3,  
17 Column 1?**

18 A. The Company's Other Operating Revenues of \$48,616,000 is an unadjusted amount that  
19 includes various revenue adjustments allocated to the North Dakota Operations. (See  
20 response to NDPSC-DR-5-027).

21 **Q. Do you have any recommendation with respect to the Company's Unadjusted Other  
22 Operating Revenues in the amount of \$48,616,000?**

- 1 A. Yes. I reviewed the Company's 2010, 2011 and 2012 NDPSC Earnings Report,  
 2 specifically the Other Operating Revenues as shown on the each of the years on pages E-  
 3 2. The following shows Other Operating Revenues for 2010 through 2012: (in \$000's)

	<u>2010</u>	<u>2011</u>	<u>2012</u>
4 ND Jurisdiction	\$41,149	\$37,594	\$39,949
5 Three Year Average			<b>\$39,564</b>

7  
 8 **Q. What conclusions did you arrive at with respect to the above computation?**

9 A. It is clear that the allocations that the Company uses to set its Other Operating Revenues  
 10 vary from year to year. As stated in the Company's Cost Assignment and Allocation  
 11 Manual (Exhibit AEH-1, Schedule 12, page 50) determination of the assignment and  
 12 allocation of costs to jurisdiction is an annual process. Therefore, the allocations of plant  
 13 and plant related costs, rate base investment, etc. change annually, and thus the  
 14 percentage allocations change annually as well.

15 Given this information, I recommend a three year average for setting the Company's  
 16 Other Operating Revenues before any adjustments made with respect to the four items as  
 17 described above on page 28. The revenues are evident and historical in nature and are  
 18 documented in the NDPSC Earnings Reports. By the use of a three year average, these  
 19 revenues are smoothed out and normalized that takes into considerations fluctuations  
 20 over the years and provides for a normalized level prospectively. My recommendation is  
 21 shown on Schedule DM-12.

22

23 a. **Asset Based Margin Sharing**

1 **Q. Please explain what Asset Based Margin Sharing is.**

2 A. According to the Company, Asset Based Margin is one of two components of Wholesale  
3 Margins (revenues less costs). The other component is Non-Asset Based Margin. In  
4 other words, Wholesale Margins are composed of Asset Based Transactions and Non-  
5 Asset Based Transactions.

6 Asset Based Transactions are comprised of short term sales of excess energy from  
7 Company owned generation assets or purchased power agreements (PPA) executed to  
8 serve native load customers. Asset based margins are earned by selling energy from  
9 facilities or PPA's that are paid for by ratepayers. The Company is proposing to credit  
10 customers 85% of Asset Based Margins based on the rate application in the North Dakota  
11 Case No. PUC-07-776 of which 85% of the Asset Based Margins were credited to  
12 customers through the Fuel Cost Rider (FCR). The Company is proposing a credit in the  
13 amount of \$505,000 as indicated in Company Exhibit AEH-1, Schedule 6, page 2 of 3,  
14 Column 18. The Company is requesting a continuation of the 85% credit to customers  
15 through the FCR, prospectively.

16

17 **Q. What is your recommendation with respect to the Asset Margin credit of \$505,000**  
18 **the Company is proposing to include in its calculation of Operating Revenues?**

19 A. I have reviewed the Company's Work paper A18-1 to 4, and have found that the  
20 Company's Minnesota and South Dakota operations do not require a sharing of the Asset  
21 Margin Credit. The Company assigns 100% of the Asset Margin Credit to its ratepayers  
22 in these states. Although this shift does not change the total Asset Margin Credit sharing,  
23 (\$505,000) it does require an adjustment to account for 100% of the \$505,000 to flow

1 through to ratepayers. In NDPSC-1-008, the Company stated that the establishment of  
2 the 85%/15% allocation was adopted in a Settlement Agreement under Case No. PU-07-  
3 776, dated December 31, 2008. Since this 85%/15% sharing mechanism was adopted in  
4 a Settlement Agreement, the NDPSC did not fully review the arguments with respect to  
5 the future or prospective sharing mechanism between shareholders and ratepayers.

6 Given this situation, the parties are free to argue the allocation between shareholders and  
7 ratepayers with respect to Asset Based Margins Credits. I recommend that the same  
8 treatment given to Minnesota and South Dakota ratepayers be given to North Dakota  
9 ratepayers, which provides for consistency across the NSP jurisdictions. Therefore I am  
10 proposing that 100% Asset Based Margin Credits be allocated to the ratepayers of North  
11 Dakota. My recommendation is shown on Schedule DM-12.

12  
13 **b. Non Asset Based Margin Sharing**

14 **Q. Please explain what Non Asset Based Margin Sharing is.**

15 A. Non Asset Margin transaction is the second component of Wholesale Margins as I  
16 indicated above. According to the Company, Non Asset Based transactions are  
17 wholesale or trading transaction undertaken to obtain margins from purchases and sales  
18 of energy unrelated to meeting the energy needs of the Company's native load customers.  
19 The Company has stated that the only transactions that qualify as non-asset based  
20 transactions are third party supplied electricity or financial transactions that are not  
21 required to meet the needs of the Company's retail customers and that are resold.  
22 As with Asset Based Margins as described above, the Company is noting the North  
23 Dakota Case No. PUC-07-776 settlement agreed to the use of a 50%/50% sharing

1 mechanism for Non Asset Based Margins. The Company is proposing a credit in the  
2 amount of \$334,000 as indicated in Company Exhibit AEH-1, Schedule 6, page 2 of 3,  
3 Column 19. The Company has indicated that this sharing mechanism is a reasonable  
4 balance of ratepayer and shareholder interest. The Company also claims that this  
5 50%/50% sharing mechanism, the incremental cost of producing the margins was  
6 reimbursed along with a reasonable contribution to joint and common costs. The  
7 Company stated that the customer portion was approved to be credited through the FCR.  
8 The Company is requesting continuation of the 50%/50% sharing mechanism in this rate  
9 proceeding as an appropriate balance of ratepayer and Company interests, along with  
10 continued credit of customers through the FCR.

11  
12 **Q. What is your recommendation with respect to the Non Asset Margin Based credit of**  
13 **\$334,000 the Company is proposing to include in its calculation of Operating**  
14 **Revenues?**

15 A. I have reviewed the Company's Work paper A19-1 through 3, and found that the  
16 Company's Minnesota jurisdictional customers do not share in Non Asset Margin Credit,  
17 and South Dakota Jurisdiction customers share Non Asset Margin Credit on the basis of  
18 70%/30%, with 70% allocated to the ratepayers.

19 I recommend that the 50%/50% sharing mechanism between shareholders and ratepayers  
20 is appropriate. My recommendation is shown on Schedule DM-12

21  
22 **c. Emission Credit Amortization**

1 **Q. Please describe the Company's request to with respect to an adjustment made for**  
2 **the Emission Credit Amortization.**

3 A. The Company has indicated that in the settlement agreement in the last rate case, the  
4 NDPSC approved a three year amortization of the cumulated balance of SO2 Allowance  
5 Credits as of December 2010. The Company is proposing to continue to amortize the  
6 outstanding balance as of December 31, 2012 in the estimated amount of \$99,000, to  
7 which the Company is requesting a three year amortization or \$33,000 per year. This is  
8 indicated in Company Exhibit AEH-1, Schedule 6, page 3 of 3, Column 30. The proposed  
9 \$33,000 per year amortization offsets the Company's SO2 Allowance credits of \$87,000  
10 for a net increase in test year revenue requirements of \$54,000. This amount is also  
11 reflected in Company Exhibit-AEH-1, page 3 of 3, Column 30.

12

13 **Q. What is your recommendation with respect to the Company's proposal on the**  
14 **Emission Credit Amortization?**

15 A. Since this Emission Credit Revenue is linked with the expense portion of the  
16 amortization of the Emission Credits, I made adjustments with respect to the Company's  
17 beginning balance of (\$87,000).

18 I agree with the Company with respect to the December 2012, balance in the amount of  
19 \$99,000. (Company work paper A-29) However, as I stated my arguments with respect  
20 to the expense portion of the Emission Credit, it is likely that the NDPSC will approve  
21 new rates that will become effective toward the end of 2013, and therefore, a full year of  
22 credit will already have taken place with respect to the Company's prior Emission Credit  
23 balance in the amount of \$87,000. Therefore, I am recalculating the outstanding credit

1 balance by removing a full year of credit (\$29,000) from the Company's outstanding  
2 credit and reducing it to (\$58,000). (\$87,000 - \$29,000). I then used the outstanding  
3 unamortized balance of \$58,000 as the amount to be included in Other Operating  
4 Revenues. This change reduces the Company's credit from its proposed (\$87,000) per  
5 year to (\$58,000) per year or a reduction of the credit in the amount of \$29,000 per year.  
6 My recommendation is shown on my Schedule DM-12; under the Adjustment Column.

7  
8 **d. MISO CWIP Revenue and Expense Adjustment**

9 **Q. Please describe the Company's proposal with respect to the MISO CWIP Revenue**  
10 **and Expense Adjustment.**

11 A. The Company claims that the NDPSC does not allow a return on long term CWIP. The  
12 Company, therefore, has removed MISO (Midcontinent Independent Transmission  
13 System Operations, Inc.) wholesale revenues that the Company has received that are  
14 related to a return on CWIP from the revenue requirement calculation for North Dakota.  
15 The Company has indicated that it received these revenues in lieu of accumulating  
16 AFUDC on these projects. The Company claims that without this adjustment, the  
17 Company would have been providing a revenue credit for wholesale CWIP recoveries  
18 even though the NDPSC does not allow a return on CWIP in base rates. The Company  
19 claims that North Dakota customers will see benefits in the form of reduced investment  
20 costs once these assets are placed in service. The Company has included a credit in the  
21 amount of \$2,188,000 in its Operating Revenues calculation as indicated in Company  
22 Exhibit AEH-1, Schedule 6, page 3 of 3, Column 31. The Company is offsetting this  
23 revenue credit with a Transmission expense credit of \$537,000. This results in a revenue

1 requirement deficiency in the amount of \$1,651,000 as indicated in Company Exhibit  
2 AEH-1, Schedule 6, page 3 of 3, Column 31.

3  
4 **Q. What is your recommendation with respect to the Company's MISO CWIP  
5 Revenue and Expense Adjustment?**

6 A. I am recommending the Company's level of MISO CWIP Revenues in the amount of  
7 \$2,188,000. My recommendation is shown on Schedule DM-12.

8  
9 **B. Operating and Maintenance Expenses**

10 **1. Fuel and Purchased Energy**

11 **Q. What is the Company proposing with respect to its Operating and Maintenance?  
12 Expenses, specifically its Fuel and Purchased Energy costs in the amount of  
13 \$82,971,000?**

14 A. The Company is not proposing any changes to its Fuel and Purchased Energy costs for its  
15 2013 Test Year (Company Exhibit AEH-1, Schedule 11, page 2 of 2). The Company  
16 recovers any changes in Fuel and Purchased Energy costs through the Fuel Cost Rider  
17 (FCR) mechanism and true up process.

18  
19 **Q. How did the Company calculate its Fuel and Purchased Energy costs for the test  
20 year period?**

21 A. The Company's 2011 actual Fuel and Purchased Energy Costs were \$76,040,000 as  
22 stated in Company Exhibit AEH-1, Schedule 3, Page 3 of 6, under the ND Retail Electric  
23 column. The Company's 2012 actual Fuel and Purchased Energy Costs were

1           \$77,805,000. The Company estimated its 2013 test year Fuel and Purchased Energy  
 2           costs to be \$82,971,000. The Company stated that its production expense budget is  
 3           mainly for fuel and purchased power. These expenses are developed from a production  
 4           budget that is prepared for the total NSP system (NSP-Minnesota and NSP-Wisconsin).  
 5           The Company's Risk Management Department uses a production simulation model and  
 6           forecasted system sales to derive the forecasted fuel and energy costs. The NSP system  
 7           fuel and energy costs are then adjusted to remove the cost of inter-system sales (asset  
 8           based sales) and other non-recoverable fuel items, so that a base cost of fuel and  
 9           purchased energy is derived. The North Dakota jurisdiction is assigned its share of the  
 10          NSP System costs.

11  
 12   **Q.    What is your position regarding the Company's Fuel and Purchased Energy costs?**

13   A.    I reviewed the Company's 2010, 2011 and 2012 NDPSC Earnings Reports, specifically  
 14          the Fuel and Purchased Energy Expenses as shown on page E-2. The following shows  
 15          the expenses for Fuel and Purchased Energy for 2010 through 2012: (in \$000's)

	2010	2011	2012
16          ND Jurisdiction	\$86,548	\$76,040	\$77,805
17          Three Year Average			<b>\$80,131</b>

18  
 19  
 20   **Q.    What conclusions did you arrive at with respect to the above computations?**

21   A.    It is clear that the allocations that the Company uses vary from year to year.

22          I recommend a three year average for setting the Fuel and Purchased Energy costs.

23          The costs are evident and historical in nature and are documented in the NDPSC Earnings

1 Reports. As stated in the Company's Cost Assignment and Allocation Manual  
2 (Exhibit AEH-1, Schedule 12, page 50) determination of the assignment and allocation of  
3 costs to jurisdiction is an annual process. Therefore, the allocations of plant and plant  
4 related costs, rate base investment, etc. change annually, and thus the percentage  
5 allocations change annually as well.

6 Given this information, I recommend that for rate making purposes, the Fuel and  
7 Purchased Energy Costs be computed using a three year average to smooth out and  
8 normalize the Fuel and Purchased Energy Costs. My recommendation is shown on  
9 Schedule DM-14.

10  
11 **2. Power Production**

12 **Q. How did the Company calculate its Power Production Expense?**

13 A. The Company calculates its Power Production Expense using the same methodology as it  
14 uses to calculate other Operating and Maintenance Expenses. As stated above, the  
15 Company prepares a production budget for the entire NSP system. The Company's Risk  
16 Management Department uses production simulation model and the forecasted system  
17 sales to derive the forecasted fuel and energy costs.

18 The Company calculated its 2011 Power Production costs at \$43,220,000. (Company  
19 Exhibit AEH-1, Schedule 3, page 3 of 6, under ND Retail Electric Column). The  
20 Company shows its 2012 actual Power Production costs at \$42,550,000. (2012 Earnings  
21 Report). The Company has proposed unadjusted Power Production Expenses of  
22 \$45,530,000 for its 2013 test year period. (Company Exhibit AEH-1, Schedule 6, page  
23 1 of 3, Column 1, and its updated Schedule 6, page 1 of 3, Column 1).

1

2 **Q. Do you have any changes to the Company's Unadjusted Power Production balance**  
3 **in the amount of \$45,530,000?**

4 A. Yes. I reviewed the Company's NDPSC Annual Reports for the years 2010, 2011 and  
5 2012 and as I calculated an average three year balance for the Fuel and Purchased Power  
6 Costs, I also calculated a three year average for the Power Production costs. The results  
7 are as indicated below (in 000's):

8

	2010	2011	2012
10 ND Jurisdiction	\$40,558	\$43,220	\$42,550
11 Three year average			<b>\$42,109</b>

12

13 **Q. What other adjustments did you make with respect to the Company's Unadjusted**  
14 **Power Production Expenses?**

15 A. I adjusted the Company's three year average Power Production costs by the Allocation  
16 Factor of 83.3% provided to me by Advocacy Witness Mr. Pavlovic. Using that factor, I  
17 reduced the three year average from \$42,109 times 83.30% or \$35,077.

18

19 **Q. What do you recommend with respect to the Company's Unadjusted Power**  
20 **Production balance?**

21 A. I recommend the use of a three year average (2010, 2011 and 2012) as the beginning  
22 balance for Power Production costs allocated by a factor of 83.30% provided to be by  
23 Mr.Pavlovic as the beginning unadjusted balance. These costs are evident, historical in

1 nature and documented in the NDPSC Annual Reports. As stated in the Company's Cost  
2 Assignment and Allocation Manual (Exhibit AEH-1, Schedule 12, page 50)  
3 determination of the assignment and allocation of costs to jurisdiction is an annual  
4 process. Therefore, the allocations of plant and plant related costs, rate base investment,  
5 etc. change annually, and thus the percentage allocations that are assigned to the North  
6 Dakota jurisdiction change annually also.

7 Given this information, I recommend that for rate making purposes, the Power  
8 Production Costs beginning unadjusted balance be computed using a three year average,  
9 multiplied by the allocation factor of 83.30% provided to me by Mr. Pavlovic. My  
10 recommendation is shown on Schedule DM-15.

11 The allocation factor of 83.30% will be discussed in Mr. Pavlovic's testimony.  
12

13 **Q. What adjustments does the Company make with respect to Power Production**  
14 **Costs for the 2013 test year?**

15 A. The Company makes four adjustments to the Power Production account, the first  
16 adjustment being Nuclear Outage Amortization in the amount of \$121,000. The second  
17 adjustment is for the Nuclear O&M Budget update in the amount of \$493,000. The third  
18 adjustment is for the Nuclear Management and the Employee Retention Program in the  
19 amount of \$77,000, and the fourth adjustment was included in the Company's updated  
20 June 6, 2013, Exhibits (AEH-1, Schedule 6, page 3 of 3 for the removal of Sherco 3  
21 Project costs in the amount of (\$227,000) . I will discuss each of these adjustments  
22 below.  
23

1           a.     **Nuclear Outage Amortization**

2     **Q.    What is the Company claiming regarding its update to the Nuclear Outage**  
3     **Amortization balance for the test year 2013?**

4     A.    The Company is including a \$121,000 increase for the 2013 test year to reflect the Fall  
5     2012 Prairie Island Unit 1 refueling outage. The Company stated that these additional  
6     costs were incurred in 2012, deferred to the balance sheet, and are amortized over the  
7     useful life of the outage. The Company claims that it is necessary to update the  
8     amortization that is included in the O & M budget. The Company stated that the change  
9     in the outage costs were reflected in the 2013 beginning of year and end of year rate base  
10    balances.

11  
12    **Q.    What is your recommendation with respect to the Company's \$121,000 increase to**  
13    **reflect the increase in the 2012 Prairie Island Unit 1 refueling outage costs?**

14    A.    The Company has computed total Company Outage Amortization by FERC for the year  
15    2013, in the amount of \$2,009,000 (WP-A6-4). The total allocation applicable to the  
16    North Dakota service area is 6.023% of the total or \$121,000 as shown on WP-A6-3.  
17    However, the 2014 projection indicates a decrease in the Company's Nuclear Outage  
18    Amortization in the amount of \$1,507,000 (WP-A6-4, 2014 column). This computes to a  
19    projected decrease to the ND Jurisdiction in the amount of \$30,000.

20  
21    **Q.    What do you conclude with respect to the Company's pro-forma Nuclear Outage**  
22    **Amortization level?**

1 A. I conclude that the Company's pro-forma expense will decrease in 2014, at the time new  
2 rates are established in this rate proceeding. Therefore, I am recommending the use of  
3 the projected Total Company 2014 Nuclear Outage Amortization in the amount of  
4 \$1,507,000, of which 6.023% is allocated to the North Dakota service area or \$90,000, a  
5 reduction of \$30,000 from the Company's proposal of \$121,000. My recommendation is  
6 shown on my Schedule DM-15, under the Adjustment Column.

7

8 **b. Nuclear O & M Budget Update**

9 **Q. What is the Company's Nuclear O & M Budget proposal?**

10 A. The Company proposed an increase in the amount of \$493,000 to reflect significant non-  
11 outage cost changes related to contract labor, materials and nuclear fees identified after  
12 the original O & M Budgets had been completed. This is the second adjustment to the  
13 Company's Power Production expense and is listed on Company Exhibit AEH-1,  
14 Schedule 6, page 1 of 3, Column 7.

15

16 **Q. Has the Company updated its proposal with respect to this adjustment?**

17 A. Yes. I reviewed the Company data request NDPSC-5-026, Supplement in which  
18 Company witness Heuer has stated on page 2, item 5 that the Monticello uprate "will not  
19 be in service until the unit has completed its power ascension testing such that the unit is  
20 reliable to operate at a higher capacity level." The Company estimates that the license  
21 will be received in early 2014. The Company has removed this adjustment from its plant  
22 in service for the test year.

23

1 **Q. How does this adjustment affect the Company's costs for the Monticello uprate In-**  
2 **Service date?**

3 A. In the Company's workpaper WP-A7-3, the Nuclear O&M Budget Adjustment shows  
4 costs associated with the Monticello and Prairie Island plants. The total O&M amounts  
5 are Monticello at \$4,700,000 and Prairie Island at \$4,949,000 for a total of \$9,649,000.  
6 Using the 5.1121% allocation factor also shown on this work paper, the original  
7 estimated cost is \$493,000. Since the Company has indicated that the Monticello In-  
8 Service date will not occur in 2013, and has removed this investment from the test year, it  
9 is also necessary to remove the associated O&M budget from the test year. The  
10 remaining costs for the Prairie Island of \$4,949,000 should be allocated to the North  
11 Dakota service area at the 5.1121% jurisdictional allocation factor and calculates to  
12 \$253,000, a decrease of \$240,000. My recommendation is shown on my Schedule DM-  
13 15, under the Adjustment Column. This is a Power Production adjustment exhibit.

14

15 **c. Nuclear Employee Retention Program**

16 **Q. What is the Company proposing with respect to its Nuclear Management Employee**  
17 **Retention Program?**

18 A. The Company has proposed an increase in the amount of \$77,000 that reflects  
19 management retention agreements that were issued to key nuclear operations employees  
20 after the budget cycle was completed and which were not included in the Company's  
21 original 2013 budget. This is the third adjustment to the Company's Power Production  
22 expense and is listed on Company Exhibit AEH-1, Schedule 6, page 1 of 3, Column 8.

23

1     **Q.   What is your recommendation regarding the Company's Nuclear Management**  
2     **Employee Retention Program?**

3     A.   The NDPSC Advocacy Staff has concerns about incentives in general seeing that in  
4     particular NSP-Wisconsin is not allowed to include employee incentives in rates.  
5     Additionally, based on the amounts of the incentives, we are concerned that these  
6     amounts are overly generous. Furthermore, it is not clear that wages in general are the  
7     main driver for employee retention. Studies usually indicate that worker satisfaction  
8     ranks higher as an employee concern than wages. If the Company is allowed these  
9     incentives in all jurisdictions, including Wisconsin, in the future, the Company can again  
10    request these costs. Results of a worker satisfaction study that assesses the concerns of  
11    workers would also be helpful to assess how salaries compared to other employee  
12    concerns.

13    My recommendation is shown on Exhibit DM-15.

14

15    **d.   Sherco 3 Project**

16    **Q.   What is the Company's fourth adjustment to its Power Production Costs?**

17    A.   The Company, in its June 6, 2013, update, has indicated that Sherco 3 will not be  
18    returning to service until the third quarter of 2013. The Company has updated the costs  
19    to remove the depreciation expense (\$22,000) and the O&M expenses in the amount of  
20    (\$227,000) related to Sherco 3 from January through September 2013.

21

22    **Q.   What is your recommendation regarding this update?**

23    A.   I agree with the Company, my recommendation is shown on Schedule DM-15.

1

2 **Q. What is your summary regarding the Power Production Expense and the four**  
 3 **adjustments as described above?**

4 A. My summary regarding the Power Production Expense and the three Power Production  
 5 Expense adjustments are summarized below:

		Recommendation
7	Company Unadjusted - 2013	\$45,530,000
8	Nuclear Outage Amortization	121,000
9	Nuclear O & M Budget Update	493,000
10	Nuclear Management Retention Program	77,000
11	Sherco 3 Update	(227,000)
12	Company Proposed 2013 Test Year	<u>\$45,994,000</u>
		<u>\$35,194,000</u>

13

14 **3. Transmission Expense**

15 **Q. What is the Company proposing with respect to its Transmission Expense,**  
 16 **unadjusted?**

17 A. In Company Exhibit AEH-1 Schedule 6 page 1 of 3, Transmission Expense is listed in  
 18 the amount of \$14,568,000. The Company then added MISO CWIP Expense (\$537,000)  
 19 to derive a projected Transmission Expense of \$14,031,000.

20

21 **Q. Do you have any changes to the Company's level of Transmission Expense in the**  
 22 **amount of \$14,568,000, unadjusted?**

1 A. As I computed a three year average for the Company's Power Production Expenses, I am  
 2 computing the same for the Company's Transmission Expense as the beginning balance  
 3 before any of the Company's projected 2013 adjustments.

4

5 **Q. What is the result of the use of a three year average for the Company's**  
 6 **Transmission Expense?**

7 A. As shown in the Company's North Dakota Earnings Reports for 2010, 2011 and 2012,  
 8 (NDPSC-5-013, Supplemental) the following are the Company's Transmission Expense  
 9 for the selected three years in (\$000's):

	2010	2011	2012
10 Transmission Expenses	\$9,725	\$11,219	\$12,309
11 Three Year Average			<b>\$11,084</b>

12

13  
 14 **Q. What other adjustments did you make with respect to the Company's three year**  
 15 **average?**

16 A. I adjusted the Company's three year average by an allocation factor of 84.50% that was  
 17 provided to me by Advocacy Staff Witness Mr. Pavlovic. Using that allocation factor I  
 18 have reduced the Company's three year average from \$11,084 to \$9,366.

19

20 **Q. Why are you recommending a three year average for the Company's Transmission**  
 21 **Expenses?**

22 A. I recommend the use of a three year average (2010, 2011 and 2012) as the beginning  
 23 balance for Power Production costs because these costs are evident, historical in nature

1 and documented in the NDPSC Earnings Reports. As stated in the Company's Cost  
2 Assignment and Allocation Manual (Exhibit AEH-1, Schedule 12, page 50)  
3 determination of the assignment and allocation of costs to jurisdictions is an annual  
4 process. Therefore, the allocation of plant and plant related costs, rate base investment,  
5 etc. change annually, and thus the percentage allocations that are assigned to the North  
6 Dakota jurisdiction change annually also. Given that this information adjusts annually,  
7 the use of a three year average provides for a smoothing of the costs over time and  
8 normalizes the expenses. I recommend that for rate making purposes, the Transmission  
9 Expense beginning unadjusted balance be computed using a three year average and  
10 allocated by the allocation factor of 84.50% as discussed by Advocacy Staff Witness Mr.  
11 Pavlovic. My recommendation is shown on Schedule DM-16.

12  
13 **a. MISO CWIP Revenue and Expense**

14 **Q. How did the Company account for its MISO CWIP Revenues and Expenses in this**  
15 **rate proceeding?**

16 A. The Company has removed the MISO Revenues and Expenses associated with  
17 transmission projects currently in CWIP. North Dakota does not allow long term CWIP  
18 in rate base. Thus, the North Dakota jurisdictional share of the transmission revenue and  
19 expenses associated with CWIP transmission projects is being excluded from the test  
20 year.

21  
22 **Q. What is your recommendation with respect to the Company's adjustment to remove**  
23 **MISO CWIP expenses in the amount of (\$537,000)?**

1 A. As I recommended for the Company's proposal to include (\$2,188,000) of MISO CWIP  
2 Revenues, I am also recommending the associated (\$537,000) of related costs. My  
3 recommendation is shown on Schedule DM-16.

4

5 **4. Distribution**

6 **Q. What is your recommendation regarding the Company's Distribution Expense in**  
7 **the amount of \$6,763,000?**

8 A. The Company's actual 2010 Distribution Expense was \$5,779,000 as shown on the ND  
9 Earnings Report, page E-2. The Company's Distribution Expense for 2011 was  
10 \$6,737,000 (Company Exhibit AEH-1, Schedule 3, page 3 of 6, ND Retail Electric  
11 column). The Company's Distribution Expense for 2012 was \$6,387,000. The  
12 Company's Distribution Expense for its 2013 test year was calculated as \$6,528,000,  
13 unadjusted. (Exhibit AEH-1, Schedule 6, page 1 of 3, Column 1).

14

15 **Q. What is your position regarding the Company's projected 2013 Distribution**  
16 **Expense before adjustments in the amount of \$6,528,000?**

17 A. As with the other Company expenses, I am recommending the use of a three year average  
18 with respect to the Company's 2013 projected Distribution Expense before adjustments  
19 in the amount of \$6,301,000. This is the average of the 2010, 2011 and 2012  
20 Distribution Expense levels as shown on page E-2 of the ND Earnings Reports (NDPSC-  
21 5-013, Supplemental).

22

1 **Q. Why are you recommending a three year average for the Company's Transmission**  
 2 **Expenses?**

3 A. I recommend the use of a three year average (2010, 2011 and 2012) as the beginning  
 4 balance for Distribution Expenses because these costs are evident, historical in nature and  
 5 documented in the NDPSC Earnings Reports. As stated in the Company's Cost  
 6 Assignment and Allocation Manual (Exhibit AEH-1, Schedule 12, page 50)  
 7 determination of the assignment and allocation of costs to jurisdictions is an annual  
 8 process. Therefore, the allocation of plant and plant related costs, rate base investment,  
 9 etc. change annually, and thus the percentage allocations that are assigned to the North  
 10 Dakota jurisdiction change annually also. Given that this information adjusts annually,  
 11 the use of a three year average provides for a smoothing of the costs over time and  
 12 normalizes the expenses. I recommend that for rate making purposes, the Distribution  
 13 Expense beginning unadjusted balance be computed using a three year average as follows  
 14 (in 000's)

	2010	2011	2012
Distribution Expense	\$5,779	\$6,737	\$6,387
Three Year average			<b>\$6,301</b>

18 My recommendation is shown on my Schedule DM-17.

19  
 20 **a. ND Line Crew Employees**

21 **Q. What is the Company's proposal with respect to an adjustment to include additional**  
 22 **North Dakota Line Crew Employees?**

1 A. The Company has added an additional line crew in its North Dakota operations in order  
2 to meet growth in the Minot service area and to improve service reliability in the Fargo  
3 and Grand Forks service areas. The cost is \$235,000. (Company Exhibit AEH-1,  
4 Schedule 6, page 1 of 3, Column 10). Company Witness, Stephen R. Foss, stated that the  
5 additional line crew is needed in anticipation of retirements during the next several years  
6 and to account for increased workloads. The additional line crew in the amount of  
7 \$235,000 is included in the Company's Distribution Expense account.

8

9 **Q. What is your recommendation regarding the Company's addition of 4 linemen in**  
10 **the amount of \$235,000?**

11 A. In the Company's WP-A10, it notes that this adjustment reflects a starting date of April 1,  
12 2013. Therefore, I agree with the Company to include the four linemen at a total cost of  
13 \$235,000. My recommendation is shown on Schedule DM-17.

14

15 **5. Customer Accounting**

16 **Q. What is the Company proposing with respect to its Customer Accounting Expenses?**

17 A. The Company's proposed Customer Accounting expense is \$4,358,000. (Exhibit AEH-1,  
18 Schedule 6, page 1 of 3, Column 1). This unadjusted amount does not include the  
19 Company's Bad Debt Expense adjustment of \$72,000.

20 The Company's 2010 Customer Accounting expense was \$4,394,000 as shown on its  
21 2010 ND Earnings Report, page E-2. The Company's 2011 actual Customer Accounting  
22 expense was \$4,411,000 (Company Exhibit AEH-1, Schedule 3, page 3 of 6, Column

1 ND Retail Electric). The Company's ND 2012 earnings report shows actual Customer  
2 Accounting expenses of \$4,128,000. (NDPSC-5-013, Supplemental).

3  
4 **Q. What are you recommending with respect to the level of the Company's Customer  
5 Accounting Expense?**

6 A. I am recommended a three year average for the Company Customer Accounting  
7 Expenses as used for other expenses as indicated previously in my testimony.

8  
9 **Q. What is the result of your calculation regarding the use of a three year average for  
10 the Company's Customer Accounting Expense?**

11 A. My adjustment is computed as follows (in 000's):

	2010	2011	2012
Distribution Expense	\$4,394	\$4,411	\$4,128
Three Year Average			<b>\$4,311</b>

15  
16 **Q. Why are you recommending a three year average for the Company's Customer  
17 Accounting Expense?**

18 A. I am recommending the use of a three year average (2010, 2011 and 2012) as the  
19 beginning balance for Distribution Expenses because these costs are evident, historical in  
20 nature and documented in the NDPSC Earnings Reports. As stated in the Company's  
21 Cost Assignment and Allocation Manual (Exhibit AEH-1, Schedule 12, page 50)  
22 determination of the assignment and allocation of costs to jurisdictions is an annual  
23 process. Therefore, the allocation of plant and plant related costs, rate base investment,

1 etc. change annually, and thus the percentage allocations that are assigned to the North  
2 Dakota jurisdiction change annually also. Given that this information adjusts annually,  
3 the use of a three year average provides for a smoothing of the costs over time and  
4 normalizes the expenses. I recommend that for rate making purposes, the Customer  
5 Accounting Expense beginning unadjusted balance be computed using a three year  
6 average as computed above. My recommendation is also shown on my Schedule DM-18.

7  
8 a. **Bad Debt Expense**

9 **Q. What is the Company proposing with respect to its Bad Debt Expense?**

10 A. The Company is proposing a decrease in the amount of \$72,000 for its 2013 test year Bad  
11 Debt Expense relating to its billed commodity revenue for the cost of utility service,  
12 including fuel charges and all regulated charges to customers, such as riders.

13  
14 **Q. Please describe the Company's methodology of calculating its Bad Debt Expense?**

15 A. The Company recognizes bad debt expense on its commodity revenue for electric and  
16 natural gas customers by estimating an amount of Accounts Reserve or Provision  
17 associated with outstanding receivables that will be unrecoverable and, writing off  
18 uncollectible accounts not previously reflected in the Accounts Reserve. The Company  
19 then calculates a weighted average ratio of bad debt to overall commodity revenue. The  
20 Company then applies this bad debt ratio to forecasted commodity revenues and allocates  
21 it between the Company's electric and natural gas operations. (WP-A9-1).

22  
23 **Q. Did the Company update its Bad Debt Expense for the 2013 test year?**

1 A. Yes, the Company used information from its June 2012 budget showing that the Bad  
2 Debt Expense should be reduced from the initial 0.41% to a 0.39% ratio. The Company  
3 then applied this ratio to the Company's commodity revenues for its North Dakota  
4 operations to compute a decrease in the amount of \$72,000.

5  
6 **Q. What is your recommendation with respect to the Company's decrease in its Bad  
7 Debt Expense in the amount of \$72,000?**

8 A. Since I have made adjustments to the Company's Retail Revenues, I also need to make  
9 adjustments with respect to the Bad Debt Expense. I utilized the Company's .39% ratio  
10 and multiplied it by my recommended Present Rate Retail Revenues of \$177,077,000 to  
11 compute a Bad Debt Expense Level of \$69,000 My recommendation is shown on  
12 Schedule DM-18.

13

14 **6. Customer Service**

15 **Q. What is the Company proposed with respect to its Customer Service & Information  
16 Expense?**

17 A. The Company is proposing Customer Service & Information Expense in the amount of  
18 \$457,000 (Company Exhibit AEH-1, Schedule 6, page 3 of 3, Column "Proposed 2013  
19 Test Year.")

20

21 **Q. How did the Company compute this level of Customer Service & Accounting  
22 Expense?**

1 A. The Company computed 2013 Customer Service & Accounting Expense by using its  
2 unadjusted balance of \$505,000 and then deducting its projected level of Advertising  
3 Expense of \$48,000. (Company Exhibit AEH-1, Schedule 6, page 2 of 3).

4

5 **Q. What is your recommendation with respect to the Company's total Customer**  
6 **Service & Information Expense in the unadjusted amount of \$505,000?**

7 A. As I computed three year averages for the beginning balances of the Company's other  
8 Operating Expenses, I am also recommending the use of a three year average for the  
9 Company's Customer Service & Information Expenses.

10

11 **Q. Please explain the use of your recommended three year average.**

12 A. I am recommending the use of a three year average (2010, 2011 and 2012) as the  
13 beginning balance for the Company's Customer Service and Information Expenses  
14 because these costs are evident, historical in nature and documented in the NDPSC  
15 Earnings Reports. As stated in the Company's Cost Assignment and Allocation Manual  
16 (Exhibit AEH-1, Schedule 12, page 50) determination of the assignment and allocation of  
17 costs to jurisdiction is an annual process. Therefore, the allocation of plant and plant  
18 related costs, rate base investment, etc. change annually, and thus the percentage  
19 allocations that are assigned to the North Dakota jurisdiction change annually also.  
20 Given that this information adjusts and changes annually, the use of a three year average  
21 provides for a smoothing of the costs over time and normalizes the expenses. I  
22 recommend that for rate making purposes, the Customer Service and Information  
23 Expense beginning unadjusted balance be computed using a three year average as

1 computed below. (in 000's) (ND-PSC Earnings Reports, 2010, 2011 and 2012, pages E-  
2 2)

	2010	2011	2012
3 Customer Service & Information	\$262	\$489	\$370
4 Three Year average			<b>\$374</b>

5 My recommendation is shown on my Schedule DM-19.  
6  
7

8 **a. Advertising**

9 **Q. What is the Company's proposal with respect to its Advertising Expense?**

10 A. The Company is proposing a decrease in its Advertising Expense in the amount of  
11 \$191,000. This is shown on Company Exhibit AEH-1, Schedule 17, page 2 of 2. The  
12 Company has indicated that this reduction in Advertising is consistent with past North  
13 Dakota rate case Orders. (Heuer Testimony page 65, lines 21-22). This \$191,000 is  
14 comprised of a decrease of \$48,000 related to Customer Programs and is part of the  
15 Customer Service & Information Account (Exhibit AEH-1, Schedule 6, page 2 of 3,  
16 Column 11), and a decrease of \$143,000 related to Brand/Image and Sponsorship and  
17 Non-Recoverable DSM and is part of the A&G Account (Exhibit AEH-1, Schedule 6,  
18 page 2 of 3, Column 11).

19 The Brand/Image and Sponsorship and Non-Recoverable DSM costs of \$143,000 will be  
20 discussed below under the A & G section.

21

22 **Q. What is your recommendation with respect to the Company's proposed \$48,000**  
23 **decrease in its Customer Service & Information Expense, Advertising Expense?**

1 A. I agree with the Company that a decrease in its Advertising Expense in the amount of  
2 (\$48,000) is appropriate. My recommendation is shown on Schedule DM-19.

3

4

5 **7. Sales, Economic Development & Other Expenses**

6 **Q. What are the Company's Sales, Economic Development & Other Expenses?**

7 A. The Company has included \$2,000, unadjusted, for 2013, for Sales, Economic  
8 Development & Other Expenses. (Exhibit AEH-1, Schedule 6, page 1 of 3). The  
9 Company's 2011 Sales, Economic Development and Other costs were \$135,000 (Exhibit  
10 AEH-1, Schedule 3, page 3 of 6, Column ND Retail Electric). In its 2010 ND Earnings  
11 report, the Company's Sales, Economic Development and Other costs were \$151,000. In  
12 its 2012 ND Earnings report, the Company's Sales, Economic Development and Other  
13 costs were \$2,000. The Company is now proposing to include an additional \$171,000 of  
14 Sales, Economic Development & Other Expenses for test year 2013 for a total amount of  
15 \$173,000 (Company Exhibit AEH-1, Schedule 6 page 3 of 3, "Proposed 2013 Test Year"  
16 column).

17

18 **Q. What is the Company's rationale with respect to including \$173,000 of Economic  
19 Development costs in its 2013 test year expenses?**

20 A. Company witness Heuer has stated that because economic development donations were  
21 recorded as below-the-line expense, an adjustment is necessary to include economic  
22 development contributions in the test year cost of service. This treatment is consistent  
23 with prior regulatory treatment in North Dakota. (Heuer Testimony page 68, lines 9-12).

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**Q. What is your recommendation with respect to the Company's inclusion of \$173,000 in Economic Development Costs for its 2013 test year period?**

A. From what I understand the Company through stipulation agreements has been allowed to recover the costs associated with Economic Development Costs in the past. Since these allowances were through a Settlement, I believe that the NDPSC did not have the opportunity to fully review these costs and make a thorough and complete decision. Therefore, Ms. Heuer's characterization that these Economic Development costs allowance as being consistent with prior regulatory treatment in North Dakota is not fully accurate. These costs were allowed in rates pursuant to a Settlement among the parties to the proceeding and not brought before the NDPSC for decision. I am recommending no inclusion of Economic Development Costs for its 2013 test year period. Short of the Company being a good Corporate Citizen, these expenditures are not required to provide safe and reliable utility service. These donations to reportedly attract economic development do not affect utility services or the Company's safety and reliability standards. In these difficult economic times, with continued high unemployment rates occurring nationwide, and where the price of many goods and services are increasing, ratepayers have to eke out a living with what income they have, and are having difficulty paying their bills. More so, ratepayers do not have a selective choice as to where their utility dollars are going regarding Economic and Development costs. This item should therefore, be accounted for below the line and the Company Shareholders should be directed to absorb 100% of the costs related to Economic Development costs.

1 Furthermore, the Commission Advocacy Staff would appreciate it if the Company did not  
 2 propose to include these costs in future rate cases as well and proposes to request the  
 3 Commission specifically mention this in its final order in this case. My recommendation  
 4 is shown on Schedule DM-20.

5  
 6 **8. Administrative & General Expenses**

7 **Q. What is the Company proposing with respect to its Administrative & General**  
 8 **Expenses (A&G)?**

9 A. The Company began with unadjusted 2013 A&G Expenses of \$15,600,000 as shown on  
 10 Company Exhibit AEH-1, Schedule 6, page 1 of 3). To that amount, the Company  
 11 included the 13 adjustments listed below to calculate an adjusted 2013 test year level in  
 12 the amount of \$14,822,000 as shown on Company Exhibit AEH-1 Schedule 6, page 3 of  
 13 3 column "Proposed 2013 Test Year."

14	Company Unadjusted – 2013	\$ 15,600,000
15	Shared Asset Allocation	(196,000)
16	Advertising	(143,000)
17	Association Dues	19,000
18	Donations	157,000
19	Customer Deposits	1
20	Aviation	(52,000)
21	Wholesale Billing	(3,000)
22	Cell Phone Policy	(7,000)
23	Rate Case Budget Exclusion	(24,000)
24	Incentive Compensation	(530,000)
25	Incentive Compensation Correction <sup>4</sup>	(6,000)
26	Pension Update <sup>5</sup>	246,000
27	Active Health Care Update <sup>6</sup>	<u>(250,000)</u>

<sup>4</sup> This expense was included in the Company's June 6, 2013, Update, Exhibit AEH-1, Schedule 6, page 3 of 3, column 35, line 13.

<sup>5</sup> This expense was included in the Company's June 6, 2013, Update, Exhibit AEH-1, Schedule 6, page 3 of 3, column 39, line 13.

<sup>6</sup> This expense was included in the Company's June 6, 2013, Update, Exhibit AEH-1, Schedule 6, Page 3 of 3, Column 40, line 13.

1  
2 Total Company Proposed \$ 14,812,000  
3

4 **Q. What is your approach with respect to the Company's proposed A&G Expenses?**

5 A. The Company began with its 2011 actual A&G expenses in the amount of \$11,770,000.  
6 (Company Exhibit AEH-1, Schedule 3, page 3 of 6, under ND Retail Electric Column.  
7 In 2010, the Company's NDPSC Earnings Report showed A&G Expenses in the amount  
8 of \$12,374,000. The Company's 2012 NDPSC Earnings Report showed 2012 A&G  
9 expenses of \$12,969,000. The Company has proposed A&G expenses of \$15,600,000 for  
10 its 2013 test year, unadjusted. (Company Exhibit AEH-1, Schedule 6, page 1 of 3,  
11 Column 1).

12  
13 **Q. What are you recommending as a beginning balance on an unadjusted basis for the  
14 Company's 2013 A&G Expenses?**

15 A. I am recommending using a three year average as the beginning balance for the  
16 Company's A&G expense, unadjusted as the starting point. My calculation is as listed  
17 below: (in 000's) (NDPSC Annual Reports for the years 2010, 2011 and 2012, pages E2).

	2010	2011	2012
A&G Expenses	\$12,374	\$11,770	\$12,969
Three Year Average			<b>\$12,371</b>

21  
22 **Q. Why are you recommending a three year average as the Company's beginning  
23 balance for A&G Expenses?**

1 A. I am recommending the use of a three year average (2010, 2011 and 2012) as the  
2 beginning balance for the Company's A&G Expenses because these costs are evident,  
3 historical in nature and documented in the NDPSC Earnings Reports. As stated in the  
4 Company's Cost Assignment and Allocation Manual (Exhibit AEH-1, Schedule 12, page  
5 50) determination of the assignment and allocation of costs to jurisdiction is an annual  
6 process. Therefore, the allocation of plant and plant related costs, rate base investment,  
7 etc. change annually, and thus the percentage allocations that are assigned to the North  
8 Dakota jurisdiction change annually also. Given that this information is adjusted and  
9 changed annually, the use of a three year average provides for a smoothing of the costs  
10 over time and normalizes the expenses. For ratemaking purposes I am recommending the  
11 use of a three year average. My recommendation is shown on Schedule DM-21.

12

13 **Q. Please describe the thirteen adjustments the Company makes to its A&G balance**  
14 **for 2013.**

15 A. As I indicated above, the Company makes thirteen adjustments to the A&G expense  
16 account. I will discuss each adjustment below.

17

18 a. **Shared Asset Allocation**

19 **Q. What is the Company's claiming regarding its Shared Asset Allocation balance for**  
20 **the test year 2013?**

21 A. The Company is including in the 2013 test year period, a decrease in the amount of  
22 \$196,000 for costs associated with assets that are shared with all Xcel Energy operating  
23 companies. (Exhibit AEH-1, Schedule 6, page 1 of 3). The Company stated that each

1 operating company shares in the total cost of assets from which the operating company  
2 derives benefits and the operating company that owns the assets is reimbursed for the  
3 other operating companies' use of its assets. The Company stated that the Shared Asset  
4 Allocation adjustment applies the shared asset to the Company's updated Capital Budget  
5 data.

6  
7 **Q. What is your recommendation with respect to the Company's Shared Asset**  
8 **Allocation decrease adjustment of \$196,000?**

9 A. I agree with the Company's proposal to decrease the amount of its Shared Asset  
10 Allocation by \$196,000. My recommendation is shown on Schedule DM-21.

11  
12 **b. Advertising**

13 **Q. What is the Company's proposal with respect to total Advertising Expense?**

14 A. The Company is proposing a decrease in its Advertising Expense in the amount of  
15 \$191,000. This is shown on Company Exhibit AEH-1, Schedule 17, page 2 of 2. The  
16 Company has indicated that this reduction in Advertising is consistent with past North  
17 Dakota rate case Orders. (Heuer Testimony page 65, lines 21-22). This \$191,000 is  
18 comprised of a decrease of \$48,000 related to Customer Program and is part of the  
19 Customer Service & Information Account as I described above, (Exhibit AEH-1,  
20 Schedule 6, page 2 of 3, Column 11), and a decrease of \$143,000 related to Brand/Image  
21 and Sponsorship and Non-Recoverable DSM and is part of the A&G Account (Exhibit  
22 AEH-1, Schedule 6, page 2 of 3, Column 11, which I will address below.

23

1 **Q. What is your recommendation with respect to the Company's proposal regarding**  
2 **the decrease in Advertising Expense related to Brand/Image and Sponsorship and**  
3 **Branding?**

4 A. I agree with the Company. However, I would like to point out, that this recommendation  
5 was not based on past rate Orders. The NDPSC has not made a recent determination as  
6 to how these costs should be reflected in rates. Nevertheless, my recommendation is  
7 shown on my Schedule DM-21.

8

9 **c. Professional and Association Dues**

10 **Q. What is the Company proposing with respect to Professional and Utility Association**  
11 **Dues?**

12 A. The Company is claiming that in its 1992 electric rate case application, Case No. PU-  
13 400-92-399, the NDPSC determined that only organizational dues related to its North  
14 Dakota operations were allowable for recovery in electric rates. The Company states in  
15 this current rate application that they have removed any organizational dues that are not  
16 related to the electric operations supporting the State of North Dakota. The total  
17 Professional and Utility Association Dues that the Company is proposing to recover in  
18 this rate application is \$19,000 as reflected in Company Exhibit AEH-1, Schedule 6, page  
19 2, Column 12. This \$19,000 reflects the addition of the \$23,000 of the Chamber of  
20 Commerce membership dues, and the exclusion of \$4,000 of non-recoverable  
21 Professional and Utility Association Dues as shown on Company Exhibit AEH-1,  
22 Schedule 18.

23

1 **Q. What is your recommendation with respect to the Company's inclusion of**  
2 **Professional and Utility Association Dues of \$19,000?**

3 A. I am recommending the removing of the Company's proposed Chamber of Commerce  
4 membership dues in the amount of \$23,000. My recommendation is based upon the fact  
5 that these types of membership dues are similar to other brand imaging costs and provide  
6 no benefit to ratepayers. These costs have no effect on the Company's duty to provide  
7 safe and reliable utility service. As shown on WP-A-12, 2013 Budget Chamber of  
8 Commerce Dues lists costs that are not specifically associated with any Chamber. The  
9 remaining dues are associated with United States Chamber and Local area Chamber  
10 Lobbying. These types of Chamber dues provide benefits solely to the Company,  
11 especially in the area of Lobbying, and therefore should not be included for ratemaking  
12 purposes. I am therefore, recommending removal of these costs. My recommendation is  
13 shown on my Schedule DM-21.

14

15 **d. Charitable Donations**

16 **Q. What is the Company claiming in respect to Charitable Donations?**

17 A. The Company is proposing to recover Charitable Donations in the amount of \$157,000  
18 in its 2013 test year. This is shown on Company Exhibit AEH-1, Schedule 6, page 2 of 3,  
19 Column 13. The Company has proposed to include 50% of Corporate Charitable  
20 Contributions that it claims benefit the State of North Dakota. The Company included  
21 50% of the Corporate Charitable contributions to ensure that only the amounts  
22 contributed to charities and institutions that could be associated with the Company's

1 electric service territory in the North Dakota jurisdiction were included in the cost of  
2 service.

3  
4 **Q. What is your recommendation with respect to the Company's inclusion of 50% of  
5 Charitable Contributions?**

6 A. In reviewing WP-A13 1 through 8, I note that there are organizations listed in the detailed  
7 data for the Company 2013 budget that the Company had donated to that should not be  
8 passed onto the North Dakota ratepayers. A selected list on WP-A13-5 shows the  
9 following:

10 Minot Indoor Rodeo, Inc.  
11 Knollwood Liquor Store  
12 Williams-Sonoma  
13 Ordway Circle of Stars  
14 Como Friends  
15 Just Give  
16 Razoo Donations  
17 Bridging, Inc.  
18 Fireworks Foundation  
19 BREDE  
20 Xcel Energy Company Store  
21

22 **Q. What do you glean from the above regarding Company donations?**

23 A. Given the list above, I do not recommend that any Charitable Donations be passed onto  
24 North Dakota ratepayers. There is no way to determine whether or not these selected or  
25 any additional donees shown on WP-AP-13, 5 through 7 provide any known utility  
26 service benefits to the North Dakota ratepayers. Even though the Company has only  
27 included 50% of its Charitable Donations in rates, I am of the opinion that none of the  
28 Charitable Donations be included as part of the Company's revenue requirement

1 proposal. Short of the Company being a good Corporate Citizen, any kind of donations is  
2 not a requirement to provide safe and reliable utility service.

3  
4 **Q. What other arguments do you have regarding Charitable Donations?**

5 A. In these difficult economic times, with still high unemployment rates nationwide, and  
6 where the prices of many goods and services are increasing, consumers have to eke out a  
7 living with what income they have. Ratepayer monies should not be used for the  
8 Company approved charitable donations. Ratepayers do not have the option to select the  
9 charities where their utility rate dollars go. The only benefit that arises out of Company  
10 donations stays within the Company. It enhances corporate image and corporate  
11 sponsorship, but it does not do anything to enhance the provision of utility service. This  
12 item should be accounted for below the line item, and the Shareholders should pay and  
13 absorb 100% of the costs related to charitable donations.

14  
15 **Q. What is your recommendation with respect to the Company's inclusion of \$157,000?**

16 A. I recommend that none of the \$157,000 be included in the Company's revenue  
17 requirement proposal. Furthermore, Advocacy Staff recommends that the Company not  
18 propose inclusion of these costs in future rate cases and will recommend that the  
19 Commission's final Order in this case include a specific finding in this regard. My  
20 recommendation is shown on Schedule DM-21.

21  
22 **e. Interest on Customer Deposits**

23 **Q. What is the Company proposing with respect to Interest on Customer Deposits?**

1 A. The Company is proposing to include an increase of \$1,000 to reflect the return on  
2 ratepayers' monies. This adjustment is reflected in Company Exhibit AEH-1, Schedule  
3 6, page 2 of 3, Column 15.

4

5 **Q. What is your recommendation regarding the inclusion of Customer Deposits in the**  
6 **amount of \$1,000?**

7 A. I agree with the Company and recommend \$1,000 to be included for Customer Deposits.  
8 My recommendation is shown on Schedule DM-21.

9

10 **f. Aviation Expense**

11 **Q. Please describe the Company's Aviation Adjustment?**

12 A. The NSPM electric utility has proposed to allocate approximately \$1.7 million in costs  
13 related to the operation of its two corporate aircraft used by Company personnel for the  
14 test year 2013, with \$105,000 being allocated to the State of North Dakota electric  
15 jurisdiction. The Company has stated that these costs are incurred in lieu of commercial  
16 aviation transportation and helps facilitate the efficient use of executive time and other  
17 employee time. The Company has indicated that the use of corporate aircraft is cost  
18 efficient. This is the sixth adjustment to the Company's A & G Expenses.

19

20 **Q. Did the Company provide any supporting documentation with respect to the**  
21 **benefits of the use of corporate aircraft?**

1 A. Yes, the Company retained a third party consultant to perform a cost-benefit analysis for  
2 the Company's corporate aircraft usage for the periods of 2011 through June 2012. The  
3 Company provided the study as Exhibit AEH, Schedule 23.  
4

5 **Q. What were the results of the study?**

6 A. The study sought to compare the benefits the Company obtained from the use of its  
7 corporate aircraft in comparison to the use of commercial airlines. The study compared  
8 door-to-door travel time, average flight times between the Company's six most common  
9 city pairs based on a comparison of actual flight times and published flight times for  
10 commercial airlines. The Study also factored in commercial air travel delays based on  
11 the Transportation Security Administration statistics. Finally the Study factored in a  
12 measure of potential lost productivity that resulted from air travel and analyzed the  
13 Company's cost per flight and commercial airfares based on historical data for a 14-day,  
14 a 3-day and a 1-day advance round trip purchase.  
15

16 **Q. What did the Study results realize?**

17 A. The Company claims that efficiencies are realized in that destinations are reached faster  
18 which allows employees to maximize their work days, as well as allowing employees to  
19 get work done in transit. The Company claimed that approximately 69% of corporate  
20 aviation costs provide a benefit when compared to the costs of commercial air travel.  
21

22 **Q. What did the Company calculate with respect to its Aviation Expense?**

1 A. The Company decreased its Aviation Expense by \$52,000. (Company Exhibit AEH-1,  
2 Schedule 6, page 2 of 3, Column 16). The Company stated that this amount was  
3 consistent with its last electric rate case, where it removed 50% of the aviation related  
4 costs. The Company also stated that the level of corporate aviation is approximately the  
5 same as was approved in its last electric rate case, which was a decrease of \$49,000. In  
6 WP-A16-1, the Company has stated that the costs included in the current rate proceeding  
7 are only for a single airplane, even though the Company maintains two airplanes.

8  
9 **Q. What is your recommendation with respect to the Company's adjustment of a**  
10 **decrease in Aviation Expenses in the amount of \$52,000?**

11 A. Questions were raised with respect to non-employee use of airplanes, i.e. spousal use.  
12 The Company has indicated that between the years 2008-2012, the percentage of use of  
13 by non-employees of the Company is about 1%. (NDPSC-2-013). The Company has also  
14 indicated that attendance of executive and Board member spouses sometimes occur for  
15 certain corporate and Board of Directors functions. The Company has indicated that it  
16 does not track whether other employees were ever required to use alternative travel  
17 arrangements because of spousal or non-employee travel.

18 Given this information, I am recommending that the Commission require the Company to  
19 track the use of its Company Aviation policy and report on its expenses, adherence and  
20 policy changes as part of its earnings reports. The report should also include evidence  
21 that the Company is using alternatives such as video-conferencing and other  
22 electronically available devices to decrease the need for travel and to allow for more

1 usage of commercial travel. With the increased availability to use electronic devices on  
2 commercial airlines, any advantages to corporate aircraft should be decreasing.

3 I am recommending the Commission set a firm budgeted amount as a benchmark for  
4 Aviation expenses in this case of \$104,000, which is the total Company proposed  
5 Aviation expenses and allow 50% of the costs or \$52,000 associated with Aviation  
6 expenses. Before any increase in the benchmark amount (\$104,000) can be allowed, the  
7 Company will have to show comparable costs of the use of Commercial airline travel  
8 service. Additionally, in the Company's next rate case proceeding, the Company should  
9 show whether or not the continued use of Corporate Airplane service is feasible or  
10 practical and less costly than Commercial Airplane service, video conferencing and  
11 greater use of electronic devices on commercial options.

12 My recommendation is shown on Schedule DM-21.

13  
14 **g. Wholesale Billing**

15 **Q. Please describe the Company's Wholesale Billing Adjustment?**

16 A. The Company stated that it performed a study of the cost to serve its single wholesale full  
17 requirements customer at cost-based rates. The Company stated that it undertook this  
18 study to ensure that the wholesale jurisdiction's cost assignment fairly represented the  
19 cost of providing service to this particular customer. The Company discussed the results  
20 of the study in Heuer's Testimony, Section VII, Utility and Jurisdictional Allocations.  
21 The Company's adjustment directly assigns \$43,000 that is related to customer billing,  
22 account management and distribution expense to the wholesale jurisdiction and decreases  
23 costs that is assigned to the retail jurisdictions by the amount of \$43,000, which a

1 decrease of \$3,000 to the North Dakota retail jurisdiction. (Company Exhibit AEH-1,  
2 Schedule 6, page 2 of 3, Column 17). The Company claimed that it does not plan to  
3 serve any cost-based wholesale requirements customers after 2013.  
4

5 **Q. What is your recommendation with respect to the Company's adjustment in the**  
6 **amount of (\$3,000) with respect to Wholesale Billing?**

7 A. I agree with the Company and have no changes to the Company's Wholesale Billing  
8 adjustment of (\$3,000). My recommendation is shown on Schedule DM-21.  
9

10 **h. Cell Phone Policy Expense**

11 **Q. Please describe the Company's Cell Phone Policy Adjustment?**

12 A. The Company has included a decrease of \$7,000 in its 2013 test year revenue  
13 requirements to reflect costs associated with employees' use of Company cell phones.  
14 The Company claims that it instituted an internal audit that revealed inconsistencies  
15 among its business units in spending for personal communication devices such as cell  
16 phones. The Company updated its policy and clarified which employees were eligible for  
17 cell phone usage and, or personal reimbursement. The Company's adjustment is  
18 reflected in Company Exhibit AEH-1, Schedule 6, page 3 of 3, Column 24.  
19

20 **Q. What is your recommendation with respect to the decrease of \$7,000 that reflects**  
21 **the costs associated with employee's use of Company cell phones?**

22 A. I agree to the decrease in the Company's Cell Phone Policy Expense in the amount of  
23 \$7,000. I also suggest that the Commission direct the Company to provide annual

1 updates with respect to the Company Cellular Phone Plan costs and changes as part of its  
2 earnings reports to assure that the Company is consistently seeking out and taking  
3 advantage of expense savings that can minimize the cost impact to the ratepayers in the  
4 North Dakota jurisdiction. My recommendation is shown on Schedule DM-21.

5  
6 **i. Incentive Compensation**

7 **Q. What adjustments has the Company proposed with respect to Incentive**  
8 **Compensation in this current rate application?**

9 A. The Company has included an adjustment to exclude budgeted costs for the long term  
10 portion of incentive compensation, any non-corporate incentive plan costs and, all annual  
11 incentive plan costs that are above 25% of base pay. The amount that the Company  
12 computed for the 25% threshold level is \$(530,000). The Company has also included  
13 certain long-term incentive costs that are associated with Restricted Stock Units that are  
14 related to Nuclear Operations employees which are also included in the revenue  
15 requirement. This is reflected in Company work paper WP-A27.

16  
17 **Q. What is the rationale for the Company to include Incentive Compensation in its**  
18 **proposed revenue requirements?**

19 A. The Company stated that its 2007 rate case application included an adjustment to exclude  
20 annual incentive plan costs above 15% of base pay. The Company is now proposing a  
21 cap of 25% of base pay. The Company claims that the 25% level is more appropriate  
22 because a 25% cap limits rate recovery associated with executive compensation without  
23 affecting rate recovery for incentive compensation for other employees.

1 The Company stated that this approach is similar to the adjustments made to remove long  
2 term incentive executive compensation. The Company is not requesting rate recovery of  
3 any portion of long term incentive compensation costs, with the exception of eligible  
4 employees in its Nuclear Business Unit. This approach is more detailed by the  
5 Company's Witness Timothy J. O'Connor. The Company stated that a 25% base salary  
6 cap would go beyond limiting executive incentive compensation and would also limit the  
7 recovery of incentive compensation for the other individual contributors and managers in  
8 the Company.

9  
10 **Q. What is the impact with respect to the Company's inclusion of Incentive**  
11 **Compensation in this current rate application?**

12 A. The inclusion of a 25% cap on incentive compensation would be a decrease to its revenue  
13 requirement in the amount of \$530,000. This is reflected in Company Exhibit AEH-1,  
14 Schedule 6, page 3 of 3, Column 26. The inclusion of a 15% cap on incentive  
15 compensation calculates to a decrease of \$619,000 as shown on data request NDPSC 1-  
16 018, Attachment A.

17  
18 **Q. What is your recommendation with respect to Incentive Compensation capped at**  
19 **25% for Nuclear Operations employees?**

20 A. I am recommending that no Incentive Compensation base pay be included in the  
21 Company's proposed 2013 revenue requirement. The Company has not provided any  
22 documentation in its rate case application to support its incentive compensation in its  
23 revenue requirement proposal. Although the Company has stated that it has various

1 incentive programs as part of its overall compensation package, (WP-A27-1), there were  
2 no such documentation filed with the rate application to support it.

3 Further, in the Application of the Northern States Power Company – Wisconsin for  
4 Authority to Adjust Electric and Natural Gas Rates, Case No. 4220-UR-117, Final  
5 Decision dated December 22, 2011, the Commission decided that “Consistent with the  
6 other large investor – owned utilities in Wisconsin in which the costs associated with  
7 incentive pay plans are not included in revenue requirements and the current economic  
8 conditions in Wisconsin, it is appropriate to limit the financial impacts on ratepayers and  
9 exclude these costs from NSPW’s revenue requirements. (page 27).  
10

11 **Q. What is your adjustment with respect to the Company level of Incentive**  
12 **Compensation capped at 25% of base pay in the amount of \$530,000?**

13 A. Given that the Commission in Wisconsin disallowed Incentive Compensation for the  
14 Northern States Power – Wisconsin, an affiliate of Northern States Power- North Dakota;  
15 it is reasonable and consistent to disallow the same in this proceeding. I have calculated  
16 removing of all of the Company’s Incentive Compensation costs as follows:

17 The level of \$(530,000) (rounded up from \$529,810) represents the amount of Incentive  
18 Compensation at a cap of 25% of base pay (WP-A27-1 through 3). The Commission had  
19 previously included a cap of 15% of base pay which calculated to an amount of  
20 \$(619,125) (NDPSC-1-018, Attachment A).

21 By lowering the cap from the original 15% cap from the 25% cap, a difference of  
22 \$89,315 is derived. (\$619,125-\$529,810). This is a 10% difference (from 15% to  
23 25%). By dividing the \$89,315 by 10%, the result is \$8,931.50 for each percent up or

1 down. I then multiplied the \$8,931.50 times 15 to reduce the remaining 15% of the  
2 incentive compensation still embedded at the 15% cap to arrive at \$133,972.50. I then  
3 added this amount to \$619,125 to arrive at the total exclusion of incentive compensation  
4 of \$753,098. My recommendation is shown on Schedule DM-21.

5  
6 **j. Rate Case Budget Exclusion**

7 **Q. Please describe the Company's position with respect to its Rate Case Budget**  
8 **Expense Adjustment?**

9 A. The Company stated that the NDPSC approves a level of rate case expense recovery as a  
10 part of each test year. The Company stated that in past years, actual rate case expenses  
11 have exceeded amounts that were approved by the NDPSC. The Company claimed that  
12 this resulted in amounts that were over the approved expense written off in the year that it  
13 occurred. The Company stated that the 2013 O & M Budget included an allowance for  
14 the write off of prior rate case expenses. The Company, in the review of its 2013 budget,  
15 identified this amount and excluded it from the test year. The Company has calculated a  
16 decrease of \$24,000 from the 2013 test year revenue requirement. This is reflected in  
17 Company Exhibit AEH-1, Schedule 6, page 3 of 3, Column 25.

18  
19 **Q. What is your recommendation with respect to this adjustment?**

20 A. I agree with the Company with respect to removal of prior rate case expenses in the  
21 amount of \$24,000. My recommendation is shown on Schedule DM-21.

22  
23

1           **k.     Pension Update**

2           **Q.     What has the Company included in its Updated filing, dated June 6, 2013, regarding**  
3           **its Pension costs?**

4           A.     The Company in its Updated June 6, 2013, filing has included an additional \$246,000  
5           related to its Pension expense. (Exhibit AEH-1, updated, Schedule 6, page 3 of 3,  
6           Column 39, line 13) (NDPSC 2-19, Attachment A, page 1 of 1).

7  
8           **Q.     Why did the Company update this expense item?**

9           A.     Company Witness Heuer stated in her response to NDPSC-5-026, Supplement, that the  
10           Pension Calculation was refreshed with 2012 year-end assumptions to account for the  
11           change in the Earned Return on Assets as being 7.25%, down from 7.50%, the SFAS 87  
12           Discount Rate as being 4.03%, down from 5.00%, the Aggregate Cost Method Discount  
13           Rate as being 7.25%, down from 7.50% and the Wage Increase assumption as being  
14           3.75%, down from 4.00%.

15  
16           **Q.     What is your recommendation with respect to the Company's updated Pension**  
17           **Expense?**

18           A.     I am in agreement with the Company in that pension costs have increased in the amount  
19           of \$246,000. I would also ask that the Company provide updates to the NDPSC  
20           beginning on December 31, 2013, and yearly thereafter to assess and evaluate the costs  
21           associated with the Company's pension balance and assumptions. In NDPSC-1-001,  
22           Company Witness, McCarten has indicated two proposals to smooth out pension costs.  
23           The first proposal is to extend the NSPM Plan amortization period for unrecognized

1 pension costs. The second proposal is to cap the Xcel Energy Services Company pension  
2 expense at the 2011 level of \$373,615 and defer the difference in excess of this level to  
3 future years. Given this information, the Company should provide scenarios and shown  
4 which method minimizes the impact on rates.

5 My recommendation is shown on Schedule DM-21.

6  
7 **I. Active Health Care Update**

8 **Q. What is the Company proposing with respect to its updated Active Health Care**  
9 **Cost?**

10 A. The Company, in its June 6, 2013, update, has included a decrease in its Active Health  
11 Care costs of \$250, 000 as shown on Exhibit AEH-1, Schedule 6, page 3 of 3, Column  
12 40, Line 13, and WP-40.

13  
14 **Q. What was the reason that the Company updated its Active Health Care costs?**

15 A. The Company has stated that it refreshed its budgeted 2013 active health care costs with  
16 2012 year-end cost data. The Company stated that the primary driver for the difference is  
17 a decline in the number of health insurance claims that were made by its employees in  
18 October through December 2012. (NDPSC-5-086, supplement).

19  
20 **Q. What is your position regarding this update?**

21 A. I agree with the Company. The Company should provide updates regarding its Active  
22 Health Care costs as costs become known. My recommendation is shown on Schedule  
23 DM-21.

1

2 **m. Incentive Compensation Correction**3 **Q. What is the Company proposing with respect to its Incentive Compensation update?**

4 A. As shown on Data Request NDPSC-5-086, Supplemental, the Company made a  
 5 correction to other Incentive Compensation to exclude Other Bonuses/Incentives that  
 6 were calculated to include costs in its Interchange Agreement billings to NSPW. The  
 7 Company determined that these costs should not have applied an Interchange Agreement  
 8 impact factor and it removed \$6 thousand with respect to Incentive Compensation.

9

10 **Q. What is your recommendation with respect to the Company's update on its**  
 11 **Incentive Compensation?**

12 A. As I stated previously, I recommended all Incentive Compensation to be removed from  
 13 the Company's revenue requirement increase. Additionally Advocacy Staff recommends  
 14 that the Company not propose recovery of incentive compensation in any future rate  
 15 cases unless the Company is allowed to recover these costs in all other jurisdictions  
 16 including Wisconsin. We will ask for specific findings in the final Order in this regard.  
 17 Given this statement, I have used the same calculated to reduce the removal of incentive  
 18 compensation from the Company's proposed 25% limitation.

19	Company Incentive Compensation at 25%	\$529,810
20	Company Incentive Compensation Correction	\$ 6,000
21	% to total	1.13%

22	Company Incentive Compensation at 15%	\$619,125
23	% removal	1.13%
24	Incentive Compensation Correction	\$6,996

25	Difference	\$996
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26	\$996 divided by 10% points	\$99.6
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1           996 times 15% to reduce Incentive to zero                                 \$1,494

2           Total Incentive Compensation Correction:

3           \$6,996 plus \$1,494   \$8,490

4           My recommendation is shown on Schedule DM-21 rounded to \$8,000.

5

6   **Q.   Is there any other adjustment related to the Company's A&G Expense that you**  
7   **would like to raise?**

8   A.   Yes. As shown on Company data request NDPSC-5-045, Attachment A, the Company  
9   has broken down O&M Expenses by labor category. I have removed all incentive  
10   compensation related to the Company's Labor. The following accounts under the Labor  
11   Category are considered incentive related pay:

12	Fuel Handling- Incentive Labor Loading	\$       844
13	Fuel Procurement – Incentive Labor Loading	\$    3,456
14	Incentive Labor Loading	\$ 483,076
15	Incentive	<u>\$ 887,381</u>
16	Total	<u>\$1,374,757</u>

17   I previously removed \$753,000 and \$77,000 in incentive related labor as indicated in  
18   section i. above, (Incentive Compensation) and in section 2, Power Production, item c,  
19   Nuclear Retention Program, respectively. The balance of the incentive compensation is  
20   therefore:

21	Total Incentive Compensation	\$1,374,757
22	Incentive Compensation (section i)	\$ 753,000
23	Nuclear Retention Program (section 2-Power Production, item c)	<u>\$ 77,000</u>

1 Balance of Incentive Compensation \$ 544,757

2 I have added a line item as shown on Schedule DM-10, line 18, to remove the remaining  
3 Incentive Compensation not specifically identified in the Company's schedules.

4

5 **C. Depreciation Expense**

6 **Q. Please explain the Company's calculation of its proposed Depreciation Expense level**  
7 **in this current proceeding?**

8 A. The Company computed a beginning unadjusted balance in its Depreciation Expense in  
9 the amount of \$21,238,000 as shown on Company Exhibit AEH-1, Schedule 6, page 1 of  
10 3, Column 1. In its Updated Exhibits dated June 6, 2013, and as shown on AEH-1,  
11 Schedule 6, the Company made nine adjustments to compute a proposed 2013 test year  
12 balance for Depreciation Expense in the amount of \$21,986,000.

13

14 **Q. What are the nine adjustments the Company made to its 2013 Unadjusted**  
15 **Depreciation Expense Balance and as updated in its June 6, 2013, Exhibits?**

16 A. The nine adjustments that were made to the Company's 2013 unadjusted Depreciation  
17 Balance is as follows:

18	Beginning Balance	\$21,238,000
19	1. Bemidji CapX2020 Project	\$ 39,000
20	2. Brookings CapX2020 Project	\$ 1,000
21	3. 2012 Depreciation Study	\$ 1,042,000
22	4. 2012 Remaining Life Depreciation Study	
23	For Productive Assets	\$ (254,000)
24	5. Black Dog Steam Plant Remediation	\$ 497,000
25	6. AFUDC Correction	\$ 5,000
26	7. Monticello License	\$ (56,000)
27	8. Projects out of 2013	\$ (7,000)
28	9. Sherco 3	\$ (22,000)



1 **Q. What is the Company proposing with respect to its Amortization Expense in this**  
 2 **rate case proceeding?**

3 A. The Company has calculated an unadjusted balance in its Amortization Expense in the  
 4 amount of \$4,000 as shown on Company Exhibit AEH-1, Schedule 6, page 1 of 3. To  
 5 that amount, the Company has made 5 adjustments as follows:

6	Beginning Balance	\$ 4,000
7	1. ND Demand Side Management	\$ 56,000
8	2. Rate Case Expense Amortization	\$206,000
9	3. Prior ND Rate Case	\$ 71,000
10	4. Private Fuel Storage Amortization	\$ 69,000
11	5. Emission Credit Amortization	<u>\$(33,000)</u>
12	Projected Balance	<u>\$ 373,000</u>

13 **Q. Please explain each of the five Amortization Adjustments and your**  
 14 **recommendations for each.**

15 **1. ND Deferred DSM**

16 **Q. Please describe the Company's proposal with respect to its Demand Side**  
 17 **Management Amortization.**

18 A. The Company stated that in Case-No. PU-08-171, (Demand Side Management and Cost  
 19 Recovery Rider Tariff) the NDPSC authorized the Company (NSP) "to record  
 20 expenditures to further promote its existing Savers Switch and Peak Energy Control  
 21 Service load management programs in a deferred account for amortization in NSP's next  
 22 general rate case. The amount deferred may not exceed \$266,904 per year."  
 23 The Settlement that was approved by the NDPSC in the Company's last rate case  
 24 included a three year amortization of the accumulated DSM balance from the 2009 and  
 25 2010 calendar years in the amount of \$450,639. The Company calculated the estimated

1 unamortized DSM balance as of December 31, 2012 in the amount of \$168,486. The  
2 Company is proposing a three year amortization of this balance, of which \$56,000 is  
3 included in this current rate proceeding. This is shown on Company Exhibit AEH-1,  
4 Schedule 6, page 2 of 3, Column 20.

5 The Company has also included \$266,583 in its 2013 O & M Budget related to DSM to  
6 represent the anticipated ongoing annual expense for DSM. The three year amortization  
7 is calculated in Company Exhibit AEH-1, Schedule 20.

8 **Q. What is your recommendation with respect to the ND DSM annual amortization of**  
9 **\$56,000?**

10 A. While I agree with the Company's three year amortization period, I believe that the  
11 balance of \$168,486 that the Company is proposing should be adjusted.

12 **Q. What adjustments do you recommend?**

13 A. Since the Company is proposing to recover the ND DSM costs over three years beginning  
14 with the year 2013 and continuing through 2015 (WP-A20-1) and it is likely that new  
15 rates will not become effective until towards the end of 2013, a full year amortization will  
16 have taken place with respect to the Company's ND DSM amortization balance of  
17 \$168,486. Therefore, I am recalculating the outstanding amortization balance by  
18 removing a full year of amortization expense (\$56,162) from the Company's outstanding  
19 amortization balance and reducing it to \$112,324. (\$168,486-\$56,162). I then amortize  
20 the \$112,324 balance over the three year period to normalize the amortization. This  
21 change reduces the Company's amortization from its proposed \$56,162 per year to  
22 \$37,441 per year (\$112,324/3) or a reduction of \$18,721 per year. My recommendation  
23 is shown on my Schedule DM-23.

1           **2.     2013 Rate Case Expense Amortization**

2   **Q.     What is the Company proposing with respect to its Rate Case Amortizations in this**  
3   **current application?**

4   A.     The Company is proposing to amortize certain test year expenses over a three-year period  
5     in order to normalize those expenses and prevent an over recovery.

6   **Q.     What is the proposed amount of the Company's Rate Case Expenses in this current**  
7   **rate application?**

8   A.     The Company is requesting approval of \$618,000 for projected direct expenses associated  
9     with this rate application, along with the use of a three-year amortization period. This  
10    results in an annual amortization amount in the amount of \$206,000. (Company Exhibit  
11    AEH-1, Schedule 6, page 3 of 3, Column 27 and, AEH-1. Schedule 19 and 20).

12   **Q.     What is your recommendation with respect to the level of proposed Rate Case**  
13   **Expenses of \$618,000 and the related proposed three-year amortization period?**

14   A.     I've review the data response NDPSC-1-015, Supplemental which shows total rate case  
15     costs as of June 21, 2013, in the amount of \$282,720. Included in the costs to date are  
16     costs associated with outside legal fees in the amount of \$83,478. These costs comprise  
17     nearly one-third of the total rate case expenses paid to date in this proceeding.

18     Given that the North Dakota electric operation is a small jurisdiction, the Company  
19     should be able to handle the case with one or two in-house attorneys. The Company  
20     should be able to minimize rate case costs without having to rely on outside legal  
21     counsel. Secondly in the area of consultants, approximately \$60,418 has been charged to  
22     outside consulting, which is 21% of the total rate case costs to date. I believe that a  
23     company of Xcel Energy's size should be able to utilize its own internal personnel to

1 process and provide consulting services including the preparation of DCF and CAPM  
2 model results. There is nothing out of the ordinary that prevents Company employees  
3 from performing these tasks.

4 Therefore, I am recommending that the costs for the Company's outside legal fees and its  
5 outside legal consultants should be removed from rate case expenses. Removal of these  
6 costs reduces the Company's to date rate case costs to \$139,124. ~~I am then doubling this~~  
7 ~~amount to \$278,248 to compute a recommended year end amount for the entire rate case~~  
8 ~~process. I am doubling the Administrative Costs of \$13,464 to \$26,928 and adding in the~~  
9 ~~State Agency Fees and Administrative Law Judge costs of \$125,380 for a total Rate Case~~  
10 ~~Expense of \$152,308.~~ I am also recommending a three year amortization period to  
11 compute an annual amount of ~~\$\$50,769 92,749~~ (rounded to ~~\$51,000 93,000~~) to be  
12 reflected in rates. My recommendation is shown on Revised Schedule DM-23.

13 **3. Prior Rate Case Expense**

14 **Q. What is the Company proposing with respect to its Prior Rate Case Amortization?**

15 A. The Company claims that its last rate case application was approved via a settlement by  
16 the NDPSC. The rate case costs in that settlement agreement included an amount of  
17 \$562,000 as well as the use of a three year amortization period. The Company has  
18 calculated an unamortized balance as of December 31, 2012, in the amount of \$212,000.  
19 The Company is requesting to extend this period for an additional three years. The  
20 resulting annual amortization expense is calculated at \$71,000. This adjustment is  
21 reflected in Company Exhibit AEH-1, Schedule 6, page 3 of 3, Column 28, and Schedule  
22 20, and in WP-A29-1.

23

1 **Q. What is your recommendation with respect to these Prior Rate Case Adjustments?**

2 A. I agree with the Company with respect to the December 2012 balance in the amount of  
3 \$212,000. However, as I stated above with respect to the Company's recovery of its ND  
4 DSM costs, it is likely that the NDPSC will approve new rates towards the end of 2013,  
5 and therefore, a full year amortization will have taken place with respect to the  
6 Company's prior rate case costs of \$212,000. Therefore, I am recalculating the  
7 outstanding amortization balance by removing a full years of amortization expense  
8 (\$71,000) from the Company's outstanding amortization balance and reducing it to  
9 \$141,000. (\$212,000-71,000). I am then amortizing the \$141,000 balance over the three  
10 year period to normalize the amortization expense. This change reduces the Company's  
11 amortization from its proposed \$71,000 per year to \$47,000 per year (\$141,000/3) or a  
12 reduction of \$24,000 per year. My recommendation is shown on my Schedule DM-22.

13

14 **4. Private Fuel Storage**

15 **Q. Please describe the Company's proposal with respect to its Private Fuel Storage**  
16 **Amortization.**

17 A. The Company claimed that it spent approximately \$23 million in order to obtain a  
18 Nuclear Regulatory Commission license for Private Fuel Storage, a private independent  
19 spent fuel storage installation within the Goshue Indian tribal land located in Utah. The  
20 Company calculated that out of the \$23 million spent, \$1.14 million was assigned to the  
21 State of North Dakota. In Case No. PU-07-776, the NDPSC approved a six-year  
22 amortization period for the \$1.14 million beginning in 2008. If the Company continued  
23 to use the six-year amortization period as directed by the NDPSC, 2013 would be the

1 final year of amortization. The Company calculated an unamortized balance at  
2 December 31, 2012 in the amount of \$208,000. The Company is proposing an additional  
3 three year amortization for this unamortized balance. This would result in an annual  
4 amortization amount of \$69,000. This is shown in Company Exhibit AEH-1, Schedule 6,  
5 page 3 of 3, Column 29, and Schedule 20, and in WP-A29-1.

6  
7 **Q. What is your recommendation with respect to the Company's amortization of its**  
8 **Private Fuel Storage?**

9 A. I agree with the Company with respect to the December 2012 balance in the amount of  
10 \$208,000. However, as I stated above with respect to the Company's other recovery of  
11 amortized costs, it is likely that the NDPSC will approve new rates towards the end of  
12 2013, and therefore, a full year of amortization will have taken place with respect to the  
13 Company's prior Private Fuel Storage costs of \$208,000. Therefore, I am recalculating  
14 the outstanding amortization balance by removing a full year of amortization expense  
15 (\$69,000) from the Company's outstanding amortization balance and reducing it to  
16 \$139,000. (\$208,000-\$69,000). I am then amortizing the \$139,000 balance over the  
17 three year period to normalize the amortization expense. This change reduces the  
18 Company's amortization from its proposed \$71,000 per year to \$46,000 per year  
19 (\$139,000/3) or a reduction of \$25,000 per year. My recommendation is shown on my  
20 Schedule DM-23.

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**5. Emission Credit Amortization**

**Q. Please describe the Company's proposed Emission Credit Amortization.**

A. The Company has stated that the Settlement approved by the Commission in its last rate case included a three year amortization of the cumulative balance of deferred Emission SO2 Allowance Credits as of December 2010. The Company is proposing to continue to amortize the outstanding balance as of December 31, 2012 in the amount of \$99,000 over a three year period. (Exhibit AEH-1, Schedule 6, Page 3, Column 30). Also included in this are costs of \$87,000 in SO2 allowance credits. This adjustment removes the budget SO2 allowance credit of \$87,000 from other revenue and adds an annual SO2 allowance amortization expense credit of approximately \$33,000 (one third of the \$99,000 December 31, 2012 estimated balance). The net effect of this adjustment is an increase in test year revenue requirements of \$54,000. (WP-A29-3 and 4).

**Q. What is your recommendation with respect to the Company's proposal to amortize the Emission Credit in the amount of \$99,000 over a three year period?**

A. I agree with the Company with respect to the December 2012 balance in the amount of \$99,000. However, as I stated above with respect to the Company's other amortized costs, it is likely that the new rates will become effective toward the end of 2013, and therefore, a full year amortization credit will have taken place with respect to the Company's prior Emission Credit balance in the amount of \$99,000. Therefore, I am

1 recalculating the outstanding amortization balance by removing a full year of  
2 amortization credit expense (\$33,000) from the Company's outstanding amortization  
3 balance and reducing it to \$(66,000). (\$99,000-\$33,000). I am then amortizing the  
4 (\$66,000) credit balance over the three year period to normalize the amortization  
5 expense. This change reduces the Company's amortization credit from its proposed  
6 (\$33,000) per year to (\$22,000) per year (\$66,000/3) or a reduction of the credit in the  
7 amount of \$11,000 per year. My recommendation is shown on my Schedule DM-23.

8  
9 **E. Taxes**

10 **1. Property Taxes**

11 **Q. What has the Company proposed with respect to Property Taxes?**

12 A. The Company has proposed Property Taxes in the amount of \$7,940,000 (Exhibit AEH-  
13 1, Schedule 6, Page 3 of 3, Proposed Test Year Column. The Company began with an  
14 unadjusted Property Tax balance of \$7,915,000 and added \$25,000 related to the  
15 Company's Bemidji CapX2020 project (Exhibit AEH-1, Schedule 6, page 1 of 3, Column  
16 2).

17  
18 **Q. Has the Company provided updates to its Property Taxes during the rate  
19 proceeding?**

20 A. Yes. In response to NDPSC-5-056, the Company updated its Property Taxes as shown  
21 on Attachment A, page 5 of 5. The updated amounts reflect total Company 2013 Electric  
22 Property Taxes in the amount of \$147,282,000 and the jurisdiction amount apportioned to

1 the North Dakota operations in the amount of \$7,142,000. This update reduces the  
2 Company's as filed amount from \$7,940,000 to \$7,142,000 or a decrease of \$798,000.

3  
4  
5 **Q. Has the Company further updated its Property Tax Expense?**

6 A. Yes. In Company response to NDPSC-5-026, supplemental, the Company has indicated  
7 that it received its Truth in Taxation notices related to increases in its 2013 State of  
8 Minnesota property taxes. The Company has indicated in its WP-A-41 updated, that its  
9 2013 property tax is calculated at \$8,119,000. (WP-A-41, Schedule 4, page 4 of 4).

10  
11 **Q. What are you recommending with respect to the Company's Property Taxes?**

12 A. I am recommending the use of the Company's updated Property Tax as shown on WP-A-  
13 41, Schedule 1, page 4 of 4). I would like to note that in the Company's Exhibit AEH-1,  
14 Schedule 6, page 3 of 3, the Company has shown total Property Taxes in the amount of  
15 \$8,114,000 a difference of \$5,000. This is the amount that I am recommending. My  
16 recommendation is shown on Schedule DM-24.

17  
18 **2. Deferred Income Tax and ITC**

19 **Q. What has the Company proposed with respect to its Deferred Income Tax and**  
20 **Investment Tax Credit (ITC) in this rate proceeding?**

21 A. The Company began with an unadjusted beginning balance in its Deferred Income Tax  
22 and ITC balance in the amount of \$10,212, 000 as shown on Exhibit AEH-1, Schedule 6,

1 page 1 of 3, Column 2, line 18. The Company updated this amount to \$12,676,000 as  
2 shown on AEH-1, Schedule 6, page 3 of 3, Proposed Test Year 2013, Column, line 18.  
3 The Company's proposed Deferred Income Taxes and ITC balance for the Projected  
4 2013 Test Year was therefore calculated at \$10,212,000 plus \$2,548,000 for a total of  
5 \$12,760,000, which is also shown on Exhibit AEH-1, Schedule 6, page 3 of 3, Proposed  
6 Test Year Column, line 18).

7  
8 **Q. What is your recommendation with respect to the Company are Deferred Income**  
9 **Tax and its ITC balance?**

10 A. I've reviewed The Company's updated workpapers as shown on NDSPC-5-026,  
11 supplemental and the updated Cost of Service documents. (Jurisdictional Input Panel  
12 Tab). I have made an adjustment to the Company's Net Operating Loss as well. I will  
13 discuss this later on in my testimony. My recommendation is shown on Schedule DM-  
14 25.

15  
16 **3. Federal and State Income Taxes**

17 **Q. What has the Company proposed with respect to the calculation of its Federal and**  
18 **State Income Taxes?**

19 A. The Company has calculated total proposed Federal Income Taxes in the amount of  
20 (\$5,610,000) (Exhibit AEH-1, Schedule 8 page 4 of 6, line 36, and total State Income  
21 Taxes in the amount of (\$870,000) line 31, for a total amount of (\$6,481,000).

22

1 **Q. What is your recommendation with respect to the Company's calculation of its**  
 2 **Federal and State Income Taxes?**

3 A. I used the same format as the Company to calculate my recommended Federal and State  
 4 Income Taxes along with my recommended adjustments for the various components of  
 5 my recommended revenue requirement. As shown on my Revised Schedule DM-26, I  
 6 am recommending total Federal Income Taxes in the amount of (\$1,863,000) \$2,046,000  
 7 and total State Income Taxes in the amount of (\$289,000 6,000), for a total Income Tax  
 8 amount of (\$2,151,000) \$1,760,000.

9

10 **4. Payroll and Other Taxes**

11 **Q. What has the Company proposed with respect to its Payroll Taxes?**

12 A. The Company has proposed Payroll Taxes in the amount of \$1,931,000 as shown on  
 13 Exhibit AEH-1, Schedule 6, page 3 of 3, Proposed Test Year 2013 Column, line 20,  
 14 Updated.

15

16 **Q. Do you have any changes to the Company's proposed Payroll Tax amount?**

17 A. Yes. As I have removed all incentive compensation related to the Company's Labor as I  
 18 previously testified to, I also reviewed Company data request NDPSC 5-045, Attachment  
 19 A, page 1 of 1, which shows total labor costs. I also need to adjust the payroll related  
 20 expenses for same. The following accounts under the Labor Category contained in  
 21 NDPSC-5-045 are incentive related pay:

22	Fuel Handling- Incentive Labor Loading	\$ 844
23	Fuel Procurement – Incentive Labor Loading	\$ 3,456
24	Incentive Labor Loading	\$ 483,076
25	Incentive	<u>\$ 887,381</u>



1 My recommended Debt Interest Calculation is computed at \$7,593,000 ~~7,500,000~~, as  
2 shown on my Revised Schedule DM-28.  
3  
4  
5  
6

7 **G. Other Ratemaking Adjustments**

8 **1. Net Operating Loss**

9 **Q. Please describe the Company position with respect to its Net Operating Loss**  
10 **Adjustment.**

11 A. The Company claimed that it has experienced income tax losses as a result of the  
12 combinations of its extensive investments and the effect of bonus federal income tax  
13 depreciation. The Company stated that bonus federal income tax depreciation is the  
14 result of provisions in federal tax laws that allow the Company to deduct either 50% or  
15 100% or qualifying capital investments in the first year the qualifying investment is  
16 placed in service. The Company stated that the Tax Relief Act of 2010, which became  
17 law in December 2010, provided 100% bonus tax depreciation for certain projects placed  
18 in service from September 9, 2010 through December 31, 2011. The Company claimed  
19 that as a result, the entire amount of the investment in qualified projects that were placed  
20 in service by the Company during that period was permitted as a tax deduction in the first  
21 year the project is placed in service.  
22

23 **Q. What effect did the Tax Relief Act of 2010 have on the Company's operations?**

1 A. The Company claims that two significant impacts occurred. The first impact was that the  
2 bonus tax depreciation generated larger amounts of deferred income taxes. The second  
3 impact was that the increased tax depreciation expense effectively resulted in more  
4 deductions than the Company can utilize in the current income tax periods. These two  
5 impacts resulted in the generation of net operating losses (NOLs) for the calendar periods  
6 2010 and 2011. The Company stated that these NOLs represented the value of tax  
7 deductions that need to be carried forward to a future period because these NOLs could  
8 not be used as deductions in current income tax periods or applied to prior periods to  
9 obtain refunds. Therefore, the Company claimed that these excess deductions and unused  
10 tax credits have been deferred and are being tracked for use in future periods.

11

12 **Q. How do these NOLs affect the Company's Rate Base?**

13 The Company stated that the NOLs require an adjustment that offsets the part of the  
14 Accumulated Deferred Income Tax (ADIT) rate base deduction associated with the  
15 accelerated and bonus depreciation deductions that have exceeded the Company's taxable  
16 income and have not resulted in deferral or income taxes.

17

18 **Q. Why do these NOL's require adjustments with respect to the Company's Rate**  
19 **Base?**

20 A. The Company claims that these NOL's require an adjustment in order to be consistent  
21 with the income tax deductions that the Company has been able to use. The Company  
22 stated that by keeping a balance of rate base reductions resulting from the ADIT and the

1 use of accelerated and bonus depreciation deductions is a requirement under federal  
2 income tax laws as are of normalization for both accounting and ratemaking purposes.

3  
4 **Q. Did the Company prepare a schedule that reflects these deferred and unused excess**  
5 **deductions?**

6 A. Yes, the Company prepared a schedule of these deferred and unused excess deductions  
7 for 2011 through 2013. The calculations are shown on Company Exhibit AEH-1,  
8 Schedule 21.

9  
10 **Q. Please explain the Company's adjustment and how it affects the revenue**  
11 **requirement proposed in this current rate application.**

12 A. The Company has proposed to include \$2,735,000 in Net Operating Losses to account for  
13 its timing differences in booked plant depreciation and taxable plant depreciation (Exhibit  
14 AEH-1, Schedule 6, Updated, page 3 of 3, column 42.

15  
16 **Q. What is your recommendation with respect to the Company's proposed NOL in the**  
17 **amount of \$2,735,000?**

18 A. I have taken the Company's proposed Rate Base in the amount of \$375,678,000 and the  
19 Company's proposed NOL of \$2,735,000 and computed a percentage to total in the  
20 amount of .728% ( $\$2,735,000/\$375,678,000$ ). I then used my recommended Rate Base  
21 amount of \$326,528,000 ~~322,514,000~~ and multiplied it by .728% to arrive at \$2,377,000  
22 2,347,000. By using a lower Rate Base and plant addition balance, the NOL becomes  
23 lower. My recommendation is shown on Revised Schedule DM-25.

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**Q. With respect to the NOLs proposed by the Company, were any additional revenues associated with this rate application computed to determine the impact of the NOLs on test year revenues?**

A. Yes. The Company has included the additional revenues it is requesting in this rate application when computing the NOL adjustment. The Company also stated that any change in the rate increase which will be granted by the NDPSC will create a change to taxable income and thus, will require a change to the calculation of the NOL adjustment.

**Q. What will be required by the Company in order to finalize the NOL adjustment at the conclusion of this rate application?**

A. The Company claimed that it will have to recalculate the NOL in order to determine the level of deductions the Company can use in the current period to reduce taxable income to zero, which will then result in a balance of unused deductions that is to be carried forward to a future period. The Company also claimed that the recalculation at the end of the rate case application will be affected by current tax depreciation deductions, annual deferred tax expense and the ADIT balance.

**VII. Interim Rate Order**

**Q. Has the Company requested and received Interim Rate Relief in this current Case No. PU-12-813?**

1 A. The Company requested and received interim rate relief in the amount of \$14,704,000 or  
2 8.05% dated January 30, 2013 and effective for service on February 16, 2013.

3

4

5

6 **Q. How much revenue did the Company bill and collect from its customers?**

7 A. In Data Request NDPSC-5-65, the Company has calculated for the months of February  
8 and March 2013, total Rate Revenues in the amount of \$1,751,175.

9

10 **Q. Has the Company updated its Collection of Interim Rate Revenues?**

11 A. No. Not as of the date of my testimony. I would recommend that the Company update its  
12 Collection of Interim Rate Revenues as soon as practicable for the months of April, May,  
13 and June, 2013. As noted in Data Request NDPSC-5-65, a request was made to continue  
14 to provide monthly incremental sales revenues collected from customers throughout this  
15 proceeding.

16 Further, since the Company has remove depreciation expense regarding the Sherco 3  
17 update (NDPSC-5-026), and the related Expenses associated with Sherco 3, the Company  
18 should not be afforded to recover these costs in its Interim Rate Relief. The Company  
19 should be required to update its Interim Rate Relief to exclude any costs associated with  
20 the Sherco 3 plant since it is not in service.

21

22 **Q. Given the fact that your recommended revenue requirement increase is less than**  
23 **what the Company has been allowed to recover (\$14,704,000), what is your**

1           **recommendation with respect to the refunded the North Dakota customers the**  
2           **excess of the revenues collected?**

3    A.    Under the North Dakota Century Code §49-05-06(4), in the event the interim rate  
4           amounts collected by the Company are in excess of the final rates approved by the  
5           Commission, the Company is required to refund the excess, included interest at a rate to  
6           be determined by the Commission.

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9    **Q.    Does this complete your testimony?**

10   A.    Yes it does.

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## Experience

### Independent Utility Rate Consultant

*(2012-Present)*

Experienced in processing, analyzing and evaluating utility rate case petitions before Public Service Commissions. Examines and evaluates rate filings, contracts, agreements and rate matters regarding utility operations and provides recommendations as to best course of action.

Analyzes and reviews utility regulatory matters and sets forth recommendations in resolving the issues. Calculates total revenue requirement needed to cover operating expenses and rate of return.

Researches and evaluates regulatory utility matters to assess impact on various classes of customers, regarding rates, service, compliance and cost of service provisions.

### New Jersey Board of Public Utilities,

*Bureau Chief-Utility Rate Manager (2002-2011)*

Managed and assigned tasks to a staff of 12 professionals and supervisory personal in the daily administrative, financial and managerial functions of the Division.

Primary duties were to ensure that the utility has sufficient revenues to cover its operating expenses, earn a return on its plant investment and to ensure that it provides safe, reliable and continuing utility service to its customers.

Set rates and charges for utility companies with revenues of up to and exceeding \$500 million. Ensured that the revenue requirement provided for recovery of all Operating Expenses, return on investment and depreciation.

Responsible for reviewing and verifying that the companies' property, plant and equipment (of up to and exceeding \$2.5 billion) was used and useful in providing service to its customers.

Coordinated and met with the New Jersey State Department of Environmental Protection to determine whether water and wastewater utilities were complying with State regulations and were adhering to any directives or Orders emanating out of the regulatory agencies.

Focused on and developed ways to minimize the rising costs of water utility services by investigating alternative rate structures, analyzing engineering mechanisms and techniques, looking into the feasibility of mergers and acquisitions within the water industry and reviewing financing and rate alternatives to minimize the impact on ratepayers.

Responsible for the adhering to the statutory timeframe in preparing, reviewing and recommending findings to the Board Commissioners on financial operations, costs, revenues and operating expenses, prior to the litigation proceedings.

Examining alternative rate recovery mechanisms and clauses, phase in of revenue requirements, deferral mechanisms and pass through of rate charges.

Assumed the role of Director during transition periods and Administrative changes.

Recruited and conducted the hiring of employees for placement within the Division and the Board.

### New Jersey Board of Public Utilities,

*Administrative Analyst (2001-2002)*

Management and Direction of small consulting firm; responsible for the design and execution of statistical, economic and financial analyses of discrete commercial operations, individual firms, and industry sectors for use by management and counsel in formulating and implementing commercial and litigation strategy.

### New Jersey Board of Public Utilities,

*Supervising Rate Analyst (1997-2001)*

Prepared detailed financial statements to evaluate and justify the utility's plant in service balance, rate of return allowance, pro forma revenues and forward looking operating expenses in order to set rates for utility service prospectively. Litigated rate cases to set policy issues, enforcement and compliance initiatives and to determine the true cost of assets acquired.

### New Jersey Board of Public Utilities,

*Accountant III, II, I (1983-1997)*

Prepared comprehensive financial spreadsheets to evaluate verify and recommend proposed utility rate case increases. Participated and provided support and reasoning as to the allocation of the revenue requirement to the various classes of customers. Through litigation, set guidelines and policy positions regarding acquisition adjustments, general cost increases, rate case sharing and post-test year plant additions. Oversaw the scope and process of Electric and Gas Levelized Adjustment Clauses, Financial Audits and Pass-through of Surcharges. Recommended a proper level of clause adjustments to be included in rates to customers.

## Education

Master Business Administration, **MBA** Strategic Management, Pace University, Lubin School of Business, New York, NY, 2010

Master Public Administration, **MPA**, Kean University, Union, NJ, 2001

Bachelor of Science, **B.S.**, Accounting, St. Peter's University, Jersey City, NJ, 1983.

**Professional Affiliations and Symposiums**

Financial Executive Networking Group (FENG) Bergen County Chapter

Institute of Public Utilities (IPU) Michigan State University (MSU), National Association of Regulatory Utility Commissioners (NARUC), 1988 and 2002

NARUC Winter and Summer Meetings, 2006 and 2007

New Jersey Utilities Association (NJUA), Annual Conference, Galloway Township, NJ, 2004

National Association of Water Companies (NAWC) New Jersey Chapter, Annual Conference, Jamesburg, NJ 1992 through 2009

[PDF to Word](#)

Filed Testimony

State of New York  
Public Service Commission

In the Matter of the Application of the Consolidated Edison Company New York, Inc.  
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and  
Regulations for Electric Service, Case No. 13-E-0030, dated January 25, 2013.

In the Matter of the Application of the Consolidated Edison Company of New York, Inc.  
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and  
Regulations for Gas Service, Case No. 13-G-0031, dated January 25, 2013.

STATE OF NORTH DAKOTA

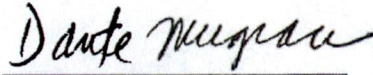
BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

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-12-813


AFFIDAVIT OF  
Dante Mgrace

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

  
Dante Mgrace

Subscribed and sworn to before me, this 17 day of July, 2013

Notary Public

District of Columbia: SS  
Subscribed and sworn to before me, in my presence,  
this 17 day of July, 2013  
  
Notary Public, D.C.  
My commission expires 7/12/2015

STATE OF NORTH DAKOTA

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

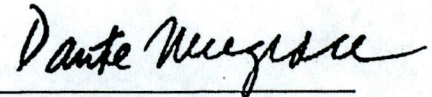
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In the Matter of the Application of  
NORTHERN STATES POWER COMPANY,  
A Minnesota Corporation for authority to  
Increase Rates for Electric Service in North Dakota

Case No. PU-12-813

AFFIDAVIT OF  
Dante Mugrace


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



Dante Mugrace

Subscribed and sworn to before me, this 22<sup>nd</sup> day of August, 2013

Notary Public



DONNA ANN JEFFRIES  
NOTARY PUBLIC DISTRICT OF COLUMBIA  
My Commission Expires July 14, 2015

**PUBLIC DOCUMENT:  
TRADE SECRET DATA EXCISED**

- Non Public Document – Contains Trade Secret Data  
 Public Document – Trade Secret Data Excised  
 Public Document

Xcel Energy

Case No.: PU-12-813

Response To: North Dakota Public Service Commission      Data Request No.      NDPSC-5-026  
**SUPPLEMENT**

Requestor: Snavelly King

Date Received: March 29, 2013

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Question:

Witness: Anne E. Heuer-Revenue Requirement (Exhibit AEH-1)

Please refer to Exhibit (AEH-1) Schedules 2 - 7. Please provide (1) Schedules 2 – 7 in electronic spreadsheet format with all formulae and macros intact and functioning and (2) workpapers documenting the development and calculation of Schedules 2 – 7, including but not limited to WP A-1, 2, 4, 22, 23, 24 and 31 referenced in Schedule 5 and WP A1-A2, WP A4-A20, WP A22-A31 referenced in Schedule 6. Provide any updates subsequent to the filing of this rate proceeding. Calculation workpapers should be provided in electronic spreadsheet format with all formulae and macros intact and functioning.

Response:

Please find enclosed a CD that includes electronic spreadsheet files for Exhibit \_\_ (AEH-1) Schedules 1 through 23 and workpapers that correspond to WP A1 through A31.

A CD that is marked NONPUBLIC also includes the Cost of Service Study model that is live-linked to the workpapers and was used to prepare Exhibit \_\_ (AEH-1), Schedule 8.

The Company does not have updates to these schedules at this time. Should the Company present updates in later Testimony, we will update this response at that time.

**SUPPLEMENT:**

Consistent with our commitment to update this response, the Company would like to present the following updates and corrections to the case as filed that reduce the North Dakota revenue deficiency from \$16.900 million to \$16.020 million. The accompanying CDs include electronic files that reflect the updates, similar to the CDs provided in the initial response to this Data Request.

**PUBLIC DOCUMENT:  
TRADE SECRET DATA EXCISED**

The updates and corrections consist of:

1. Removing the Black Dog Remediation adjustment. As discussed in Exhibit \_\_ (AEH-1), Heuer Direct, page 50-51, the Company identified that the Black Dog Remediation adjustment was already included in the Remaining Life adjustment and therefore is duplicative. This update removes the duplicative adjustment.
2. AFUDC correction. A computer error was identified subsequent to filing the case that incorrectly calculated AFUDC in the base data. This update adjustment corrects the AFUDC calculations in the base data.
3. FAS 106 correction. A data entry error was identified subsequent to filing the case. This update adjustment corrects the FAS 106 amount that should be included.
4. Incentive Compensation correction. The amounts excluded for Other Bonuses/Incentives were calculated assuming that these costs are included in our calculation of Interchange Agreement billings to NSPW. However, we found that they are not, and we should not have applied an Interchange Agreement impact factor. This update adjustment corrects for that calculation error.
5. Monticello NRC License In-Service update. The case as filed reflected 2013 NRC licensing costs associated with the Monticello LCM/EPU addition scheduled to go into service in August and November of 2013. The investment associated with obtaining the 2013 NRC license is not in service until the unit has completed its power ascension testing such that the unit is reliable to operate at a higher capacity level. We estimate the in-service date for the license will be early 2014. This update adjustment removes the plant-in-service related to this investment from the test year.
6. Capital No Longer in Test Year update. We reviewed the in-service dates of several capital projects with December 2013 in-service dates as well as any projects that have been cancelled subsequent to filing the case. We identified seven projects that are no longer scheduled to be in service within the test year, either due to cancellation or due to a change in the in-service date. This update adjustment removes the plant-in-service related to these investments.
7. Sherco 3 Online Date update. In November 2011 there was a significant failure at Sherco 3, which resulted in an extended outage. The budget included with the case as-filed assumed an early 2013 return to service. We now expect the unit to return to service in the third quarter of 2013. This update adjustment removes the depreciation expense and O&M related to Sherco 3 from January through

**PUBLIC DOCUMENT:  
TRADE SECRET DATA EXCISED**

September, 2013.

8. Pension Calculations update. We refreshed our budgeted 2013 pension expense with 2012 year-end assumptions. The updated assumptions are:
  - a. The Earned Return on Assets (EROA) is 7.25 percent, down from 7.5 percent assumed in the as-filed case.
  - b. The SFAS 87 Discount Rate is 4.03 percent, down from 5.00 percent assumed in the as-filed case.
  - c. The Aggregate Cost Method (ACM) Discount Rate is 7.25 percent, down from 7.5 percent assumed in the as-filed case.
  - d. The Wage Increase assumption is 3.75 percent, down from 4.0 percent assumed in the as-filed case.
  
9. Active Health Care update. We refreshed our budgeted 2013 active health care costs with 2012 year-end cost data. The primary driver for this difference is a decline in the number of health insurance claims made by our employees in October through December 2012.
  
10. Property Tax update. The Company received Truth in Taxation notices relating to increases in its 2013 State of Minnesota property taxes. The State of Minnesota also published updated cap rates used to calculate property taxes. This update adjustment reflects the newest data that relate to 2013 property tax costs allocated to the State of North Dakota.
  
11. Secondary impacts to Net Operating Loss, Cost of Capital, and Cash Working Capital. By making these update and correction adjustments, the secondary Cost of Service calculations relating to the Net Operating Loss, Cost of Capital, and Cash Working Capital impacts must be updated to be consistent.

We also provide updated Heuer Schedules 4-8 to be consistent with the updates and corrections listed above.

- Exhibit \_\_ (AEH-1), Schedule 4, UPDATED List of Adjustments
- Exhibit \_\_ (AEH-1), Schedule 5, UPDATED Test Year Bridge Schedule, Rate Base
- Exhibit \_\_ (AEH-1), Schedule 6, UPDATED Test Year Bridge Schedule, Income Statement
- Exhibit \_\_ (AEH-1), Schedule 7, UPDATED Summary of Revenue Requirements
- Exhibit \_\_ (AEH-1), Schedule 8, UPDATED 2013 Cost of Service Study

Please note that portions of the data provided with this response are marked "Non-Public" consistent with the trade secret application dated April 9, 2013 in this case.

**PUBLIC DOCUMENT:  
TRADE SECRET DATA EXCISED**

Witness: Anne E. Heuer  
Preparer: Charles Burdick  
Title: Principal Rate Analyst  
Department: Revenue Requirements North  
Telephone: 612-330-6646  
Date: April 12, 2013

**SUPPLEMENT:** June 6, 2013

- Non Public Document – Contains Trade Secret Data  
 Public Document – Trade Secret Data Excised  
 Public Document

Xcel Energy

Case No.: PU-12-813

Response To: North Dakota Public Service Commission      Data Request No.      NDPSC-5-013

Requestor: Snavelly King

Date Received: March 29, 2013

**SUPPLEMENT**

---

Question:

Witness: Anne E. Heuer-Revenue Requirement (Exhibit AEH-1)

Provide a copy of the Northern States Power Company-North Dakota's Public Service Commission Annual Reports for the calendar years 2010, 2011, and when available, 2012.

Response:

Please see Attachment A, for a copy of NSPM's 2010 electric and gas Annual Jurisdictional Report for North Dakota.

Please see Attachment B, for a copy of NSPM's 2011 electric Annual Jurisdictional Report for North Dakota.

We will supplement this response with the 2012 report once it is available.

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**SUPPLEMENT:**

Please see Attachment C, for a copy of NSPM's 2012 electric Annual Jurisdictional Report for North Dakota.

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Preparer: Amber Hedlund  
Title: Regulatory Administrator  
Department: Regulatory Affairs  
Telephone: 612-337-2268  
Date: April 8, 2013

**SUPPLEMENT: May 2, 2013**

**ANNUAL REPORT**

**OF**

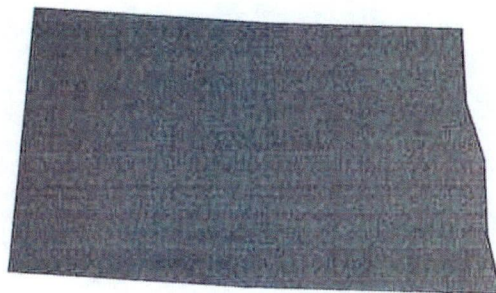
**NORTHERN STATES POWER COMPANY,**  
**A MINNESOTA CORPORATION**

**TO THE**

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

**FOR THE YEAR ENDING**  
**DECEMBER 31, 2012**

**North Dakota Jurisdiction**  
Electric Utility



**2012**

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<b>III. Average Rate Base</b>	<b>E-3</b>
<b>IV. Cost of Capital</b>	<b>E-4</b>
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<b>III. Elec &amp; Gas Affiliated Transactions</b>	<b>S-3</b>

## Northern States Power Company Electric Utility - North Dakota

(Dollars In Thousands)

### I. RETURN ON EQUITY (ROE)

<u>Actual Return on Equity (ROE)</u>	<u>2012</u>	<u>2011</u>
1 Operating Income from Electric Operations (E-2):	\$24,371	\$24,952
2 Average Regulated Rate Base (E-3):	\$338,666	\$322,995
3 Rate of Return on Rate Base (ROR) (line 1 / line 2):	7.20%	7.73%
4 Weighted Cost of Debt (E-4):	2.61%	2.88%
5 Weighted Cost of Preferred Stock (E-4):	0.00%	0.00%
6 % of Equity in Capital Structure (E-4):	52.78%	52.67%
7 Return on Equity (ROE):	8.69%	9.20%

<u>ROE, Normalized for Weather Impact on Sales</u>	<u>2012</u>	<u>2011</u>
8 Operating Income from Electric Operations:	\$24,371	\$24,952
9 Impact of weather on Mwh Sales:	(24,994)	9,730
10 Impact of weather on Electric Operating Income: <sup>1</sup>	(\$407)	\$254
11 Weather-Normalized Operating Income:	\$24,778	\$24,698
12 Average Regulated Rate Base:	\$338,666	\$322,995
13 Weather-Normal Rate of Return on Rate Base (ROR):	7.32%	7.65%
14 Weather-Normalized Return on Equity (ROE):	8.92%	9.05%

<sup>1</sup> Beginning in 2012 the weather impact estimate includes a demand component in addition to sales.

## Northern States Power Company Electric Utility - North Dakota

(Dollars In Thousands)

### II. OPERATING INCOME

<u>Line</u>	<u>Item</u>	<u>2012 Total NSP</u>	<u>2012 N.D. Juris.</u>	<u>N. D. %</u>	<u>2011 N.D. Juris.</u>	<u>Annual Change</u>
<b><u>Operating Revenues:</u></b>						
1	Residential	1,166,495	69,329	5.9%	68,744	0.8%
2	Small Comm. & Ind.	1,326,542	85,328	6.3%	83,167	2.6%
3	Large Comm. & Ind.	633,557	22,301	3.4%	21,516	3.6%
4	Public Street & Highway Ltg	26,142	1,540	6.2%	1,616	-4.7%
5	Other Sales to Publ Auth	<u>8,330</u>	<u>1,159</u>	<u>15.0%</u>	<u>1,246</u>	<u>-7.0%</u>
	Total Retail	3,161,066	179,657	5.6%	176,290	1.9%
6	Interdepartmental	532	0	0.0%	0	*
7	Sales for Resale	74,264	4,511	6.1%	4,497	0.3%
8	Interchange Agreement	449,958	26,898	5.8%	26,283	2.3%
9	Other	<u>112,083</u>	<u>8,540</u>	<u>6.1%</u>	<u>6,814</u>	<u>25.3%</u>
10	Total Revenues:	<u>3,797,903</u>	<u>219,606</u>	<u>5.8%</u>	<u>213,884</u>	<u>2.7%</u>
<b><u>Operating Expenses:</u></b>						
11	Fuel & Purchased Energy	1,242,746	77,805	6.3%	76,040	2.3%
12	Production	727,894	42,550	5.8%	43,220	-1.6%
13	Transmission	210,577	12,309	5.8%	11,219	9.7%
14	Distribution	111,134	6,387	5.7%	6,737	-5.2%
15	Customer Billing	53,705	4,128	7.7%	4,411	-6.4%
16	Customer Service	103,566	370	0.4%	489	-24.3%
17	Sales & Marketing	68	2	2.9%	135	-98.5%
18	Admin. & General	222,349	12,969	5.8%	11,770	10.2%
19	Depreciation & Amortization	384,321	20,400	5.3%	17,885	14.1%
20	Property Taxes	151,204	6,690	4.4%	5,881	13.8%
21	Payroll & Other Taxes	31,462	1,866	5.9%	1,820	2.5%
22	Income Taxes	0	0	*	(1,111)	-100.0%
23	Deferred Income Taxes & ITC	<u>156,513</u>	<u>9,759</u>	<u>6.2%</u>	<u>10,436</u>	<u>-6.5%</u>
24	Total Expenses:	<u>3,395,539</u>	<u>195,235</u>	<u>5.7%</u>	<u>188,932</u>	<u>3.3%</u>
25	Regulated Operating Income	<u>402,364</u>	<u>24,371</u>	<u>6.1%</u>	<u>24,952</u>	<u>-2.3%</u>

## Northern States Power Company Electric Utility - North Dakota

(Dollars In Thousands)

### III. AVERAGE RATE BASE

<u>Line</u>	<u>Item</u>	<u>2012</u> <u>Total NSP</u>	<u>2012</u> <u>N.D. Juris.</u>	<u>N. D. %</u>	<u>2011</u> <u>N.D. Juris.</u>	<u>Annual</u> <u>Change</u>
1	Plant in Service	14,347,235	780,660	5.4%	742,545	5.1%
2	Accumulated Depreciation	6,821,974	379,380	5.6%	364,662	4.0%
3	Net Plant in Service	7,525,261	401,280	5.3%	377,883	6.2%
4	Plant Held for Future Use	0	0	*	0	*
5	Construct Work in Progress	51,931	2,936	5.7%	657	346.9%
6	Materials and Supplies	128,683	7,471	5.8%	7,213	3.6%
7	Fuel Stocks	90,424	5,634	6.2%	5,454	3.3%
8	Prepayments & Other Rate Base	82,396	4,830	5.9%	3,833	26.0%
9	Customer Deposits	(3,188)	(29)	0.9%	(15)	93.3%
10	Cash Working Capital	0	0	*	0	*
11	Other Rate Base <sup>1</sup>	(63,118)	(3,776)	6.0%	(3,903)	-3.3%
12	Accum. Deferred Taxes	(1,679,223)	(79,680)	4.7%	(68,127)	17.0%
13	Total Other Rate Base	(1,392,095)	(62,614)	4.5%	(54,888)	14.1%
14	Total Average Rate Base	6,133,166	338,666	5.5%	322,995	4.9%

<sup>1</sup> Includes deferred assets and liabilities such as accrued vacations, post-retirement medical benefits (FASB 106), post employment benefits (FASB 112), unfunded pension liability, environmental cleanup, severance accrual, etc.

## Northern States Power Company Electric Utility - North Dakota

(Dollars In Thousands)

### IV. COST OF CAPITAL

<u>2012 Actual</u>					
<u>Line</u>	<u>Item</u>	<u>Amount</u>	<u>% of Total</u>	<u>Cost</u>	<u>Weighted Cost</u>
1	Long-Term Debt	\$3,360,934	45.38%	5.71%	2.59%
2	Short-Term Debt	<u>\$136,000</u>	<u>1.84%</u>	<u>0.98%</u>	<u>0.02%</u>
3	Total Debt	\$3,496,934	47.22%	5.52%	2.61%
4	Preferred Stock	\$0	0.00%	0.00%	0.00%
5	Common Equity	<u>\$3,908,649</u>	<u>52.78%</u>	<u>8.69%</u>	4.59%
6	Total Equity	\$3,908,649	52.78%		
7	Total Capital	\$7,405,583	100.00%		7.20%

<u>2012 Normalized</u>					
<u>Line</u>	<u>Item</u>	<u>Amount</u>	<u>% of Total</u>	<u>Cost</u>	<u>Weighted Cost</u>
8	Long-Term Debt	\$3,360,934	45.38%	5.71%	2.59%
9	Short-Term Debt	<u>\$136,000</u>	<u>1.84%</u>	<u>0.98%</u>	<u>0.02%</u>
10	Total Debt	3,496,934	47.22%	5.52%	2.61%
11	Preferred Stock	\$0	0.00%		0.00%
12	Common Equity	<u>\$3,908,649</u>	<u>52.78%</u>	<u>8.92%</u>	4.71%
13	Total Equity	\$3,908,649	52.78%		
14	Total Capital	\$7,405,583	100.00%		7.32%

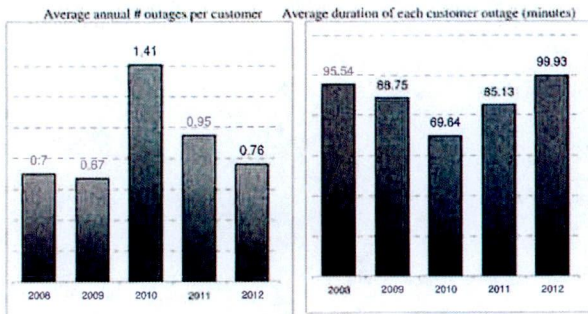
Northern States Power Company  
Electric Utility – North Dakota

Case No. PU-12-813  
Data Request No. NDPS-5-013 Supplement  
Attachment C - Page 7 of 13

**Xcel Energy**  
**Annual Reliability Report**  
**Outage Frequency and Duration Indices**

**System Avg Interruption Frequency Index (SAIFI)**

**Customer Avg Interruption Duration Index (CAIDI)**



Index	Normaliz	Normaliz
	SAIFI	CAIDI
2008	0.70	95.5
2009	0.67	88.8
2010	1.41	69.6
2011	0.95	85.1
2012	0.76	99.9

**SAIFI - Largest Five Substations**

	2008	2009	2010	2011	2012	5 Yr. Avg
Souris (Mnt)	0.58	0.48	0.29	0.88	0.36	0.52
Gateway (GF)	0.61	0.18	0.68	0.78	0.59	0.57
Cass County (Fgo)	0.44	0.58	0.67	0.82	0.71	0.64
Nordic (GF)	0.58	0.57	2.52	0.88	1.01	1.11
Red River (Fgo)	0.97	1.03	1.96	1.02	0.70	1.14

**CAIDI - Largest Five Substations**

	2008	2009	2010	2011	2012	5 Yr. Avg
Souris (Mnt)	66.7	61.0	82.7	71.2	105.8	77.5
Red River (Fgo)	94.0	81.4	70.3	73.8	110.1	85.9
Nordic (GF)	102.2	97.0	61.8	95.7	74.1	86.2
Gateway (GF)	113.7	122.1	47.9	109.1	89.1	96.4
Cass County (Fgo)	101.6	90.8	115.2	103.3	78.6	97.9

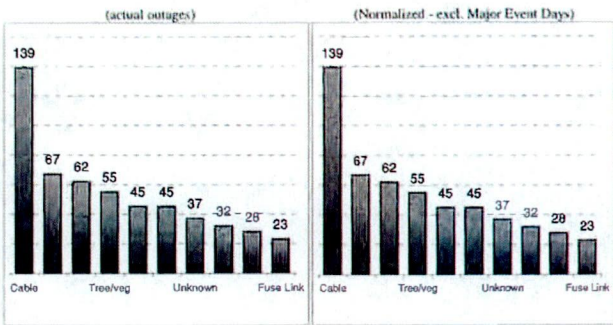
Data reflects outages lasting 5 minutes or longer. There were no Major Event Days in 2012 to normalize.

Northern States Power Company  
Electric Utility – North Dakota

Case No. PU-12-813  
Data Request No. NDPSC-5-013 Supplement  
Attachment C - Page 8 of 13

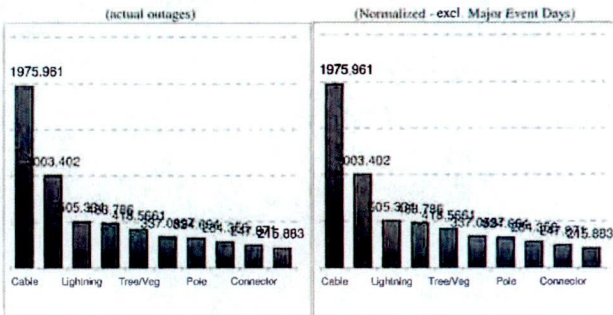
**Xcel Energy**  
**Annual Reliability Report**  
**Most Common Outage Causes**

**Top 10 Outage Causes**



Input Section	Actual Events	Excl. MEDs
1 Cable	139 Cable	139
2 Intentional	67 Intentional	67
3 Animal	62 Animal	62
4 Tree/veg	55 Tree/veg	55
5 Connector	45 Connector	45
6 Public Dan	45 Public Dan	45
7 Unknown	37 Unknown	37
8 Overload	32 Overload	32
9 Transform	28 Transform	28
10 Fuse Link	23 Fuse Link	23

**Top 10 Causes of Lengthy or Wide-spread Interruptions**  
(measured in customer-minutes without power - 000's)

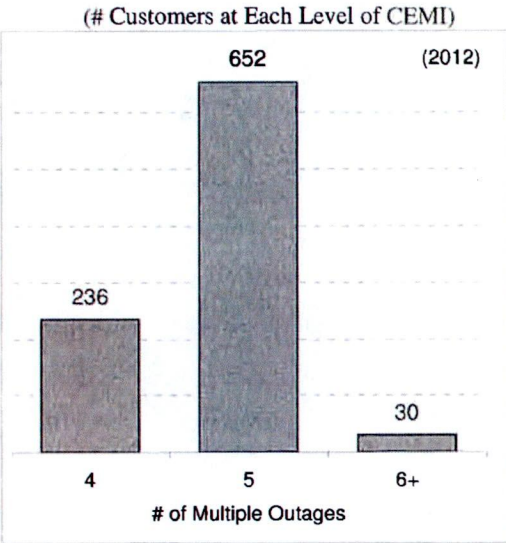


Input Section	Actual CMO	Excl. MEDs
1 Cable	1975.961 Cable	1,975.961
2 Intentional	1,003.402 Intentional	1,003.402
3 Lightning	505.388 Lightning	506
4 Relay	484 Relay	484
5 Tree/Veg	419 Tree/Veg	419
6 Public Dan	337 Public Dan	337
7 Pole	325 Pole	325
8 Insulator	284 Insulator	284
9 Connector	248 Connector	248
10 Conduct C	216 Conduct C	216

Note: Data reflects outages lasting 5 minutes or longer.

**Xcel Energy  
Annual Reliability Report  
CEMI, Feeder Outages, and Underground Cable Failures**

**Customers Experiencing Multiple Interruptions  
(CEMI)**

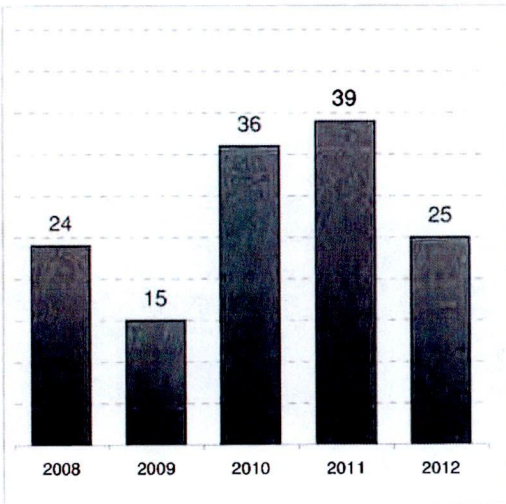


**Annual CEMI Credit Results**

Year	Customers w > 3 interr.	CEMI Credits
2012	918	none
2013		
2014		
2015		

Input Section	
CEMI Outages	CEMI Cust
4	236
5	652
6+	30

**Feeder-Level Outages**



**Underground Cable Failures**

Year	UG Cable Failures
2010	137
2011	149
2012	139
2013	
2014	
2015	

Input Section	
Fdr lvl outages	Fdrs
2008	24
2009	15
2010	36
2011	39
2012	25

(reflects primary, secondary cable failures)

Data reflects outages lasting 5 minutes or longer; Major Event Days and public damage events excluded.

Xcel Energy  
Electric Utility – State of North Dakota  
2013 Reliability Plan Summary

**Overhead Line Upgrades - \$1,522,000**

Xcel Energy's 2013 capital budget includes about \$1,522,000 to upgrade its electric overhead system in North Dakota. These improvements include replacing failed devices, installing upgrades necessary to the backbone system to serve new customers, and improvements to enhance reliability. Included in this effort is funding for our Reliability Exception Monitoring System ("REMS") program. This computer-based system initiates an engineering review of a part of our system by flagging any device that has tripped more than twice in a rolling 12 month period. Following such a review, corrective actions are identified and implemented where appropriate.

**Underground Cable Upgrade - \$903,000**

In 2013, Xcel Energy plans to spend about \$903,000 in capital funds to upgrade its underground cable system in North Dakota. A little over half of these expenditures will include replacing cables that have failed but are not fit to be repaired and returned to service. They also include cables that may have experienced multiple failures in the past but for which repairs still present a viable remedy. Projects will involve the installation of additional backbone system capacity to serve new load or relieve load on existing facilities.

In addition, these funds reflect Xcel Energy's continued efforts to proactively locate and remove non-jacketed 500 MCM cable remaining on our system. This project reflects one of several Settlement commitments from Case No.'s PU-10-657 and PU-11-55. The company plans to spend about \$450,000 in 2013 on this project. The total program has been extended from its initial 3 year term (2012 – 2014) to a 4 year project, and the expenditure budget increased from \$750,000 to \$1,700,000, using funds available from the Company's Intelliteam project.

**Distribution Pole Testing - \$47,000**

Xcel Energy's 2013 pole replacement plan includes an operating and maintenance expense budget of \$47,000 for testing wood distribution poles in North Dakota. The testing methodology conforms to a scientific procedure that is utilized throughout the industry. It includes a visual check and test of remaining pole strength. If a pole is identified as having strength characteristics below acceptable standards, the pole is scheduled for replacement or reinforcement. The expense budget for this program is subject to ongoing adjustments based on the Company's overall financial situation throughout the plan year.

## Northern States Power Company Supporting Information - North Dakota

### I. Sales and Customer Data

#### Electric Utility (N. D. Jurisdiction)

<u>Line</u>	<u>Customers (@ Dec)</u>	<u>2012</u>	<u>2011</u>	<u>2010</u>	<u>2009</u>	<u>2008</u>
1	Residential	77,231	76,126	76,319	75,608	75,036
2	Small C & I	12,182	12,033	12,078	11,989	11,895
3	Large C & I	21	20	20	19	22
4	PSHL/OSPA	<u>322</u>	<u>280</u>	<u>284</u>	<u>283</u>	<u>280</u>
5	Total Retail	89,756	88,459	88,701	87,899	87,233
<u>Line</u>	<u>Mwh Sales</u>	<u>2012</u>	<u>2011</u>	<u>2010</u>	<u>2009</u>	<u>2008</u>
6	Residential	758,810	776,125	769,024	794,420	761,934
7	Small C & I	1,069,443	1,085,821	1,057,747	1,116,612	1,093,952
8	Large C & I	349,595	350,764	349,581	310,239	328,203
9	PSHL/OSPA	<u>29,553</u>	<u>29,790</u>	<u>29,528</u>	<u>25,354</u>	<u>26,057</u>
10	Total Retail	2,207,401	2,242,500	2,205,880	2,246,625	2,210,146
11	Ave. ¢/Kwh	8.10	7.85	7.24	7.10	7.33
12	Ave. Res. Monthly Usage (kwh)	819	850	840	876	846
13	Ave. Res. Monthly Bill	\$74.46	\$75.16	\$68.32	\$69.96	\$69.19

Northern States Power Company  
Electric Utility – North Dakota

Case No. PU-12-813  
Data Request No. NDPSC-5-013 Supplement  
Attachment C - Page 12 of 13

**Xcel Energy**  
**Supporting Information - North Dakota**  
**II. AFFILIATED TRANSACTIONS Summary**

Line #	Affiliate Name	General Description of Services Rendered &/or Supplied	Portion Allocated to North Dakota Jurisdiction Electric and Gas Totals (1)	
			Expense (2)	Revenue (3)
1	Northern States Power Company (Wis.)	Electric and Gas Utility	7,356,944	26,916,044
2	Public Service of Colorado	Electric and Gas Utility	5,460	7,179
3	Southwestern Public Service	Electric Utility	2,012	962
4	United Power and Land	Real estate holdings	-	54
5	Eloigne Company	Affordable housing investment program	-	1,220
6	Xcel Energy Services	Xcel Energy Inc. service company	15,886,741	-
7	e'Prime	Engineering services	-	-
			<u>23,251,156</u>	<u>26,925,459</u>

Notes:

- (1) The amounts allocated to North Dakota electric and gas jurisdictions represent an estimate based on an overall allocation factor applied to all of the revenues and expenses for each affiliate. To derive the actual amounts by jurisdiction would require an allocation by transaction by account number and would require significant analysis and expense to perform.
- (2) Expense to North Dakota electric and gas jurisdictions. Revenue to affiliate for services provided to NSP (Mn).
- (3) Revenue to North Dakota electric and gas jurisdictions. Expense to the affiliate for services provided to the affiliate by NSP (MN).

Northern States Power Company  
Electric Utility – North Dakota

Case No. PU-12-813  
Data Request No. NDPSC-5-013 Supplement  
Attachment C - Page 13 of 13

**Xcel Energy**  
**Supporting Information - North Dakota**  
**III. Affiliated Transactions Summary**

	<u>Total Expense</u>	<u>Total Revenue</u>	<u>Elec %</u>	<u>Gas %</u>	<u>(Customers) ND Elec%</u>	<u>(Customers) ND Gas%</u>	<u>Allocation Used (1)</u>
NSP Wis.	700,842	952,566	92.2092%	7.7908%	6.3320%	9.9502%	Common
PSCo	86,227	113,381	100.0%	0.0%	6.3320%	0.0%	Electric
SPS	31,778	15,191	100.0%	0.0%	6.3320%	0.0%	Electric
UP&L	-	819	92.2092%	7.7908%	6.3320%	9.9502%	Common
Eloigne	-	18,443	92.2092%	7.7908%	6.3320%	9.9502%	Common
XES	240,202,796	-	92.2092%	7.7908%	6.3320%	9.9502%	Common
ePrime	-	-	100.0%	0.0%	6.3320%	0.0%	Electric
	<b>241,021,643</b>	<b>1,100,400</b>					

**(1) Allocation of Revenues & Expenses between NSP Minnesota and Affiliates**

Common Allocation Methodology is Labor	<u>Electric</u>	<u>Gas</u>	<u>Load Dispatch</u>	
Utility Labor Allocator	92.9310%	7.0690%	<b>Design Day</b>	10.6373%
Customers North Dakota Jurisdictional	6.3320%	9.9502%		
Factor Formula: ((Util Elec)*ND Jur Ele)+((Util Gas)*ND Jur Gas) =				6.5878%

**(2) Affiliated Transactions between Minnesota and Wisconsin**

	<u>Total</u>	<u>ND Alloc.</u>		<u>Total</u>	<u>ND Alloc.</u>	<u>Alloc. Method</u>	<u>ND Alloc. %</u>
<b>Electric Inter change Agreement dollars</b>				<b>Expenses</b>			
<b>Revenues</b>	195,624,441	11,259,947	Fixed	45,205,562	2,601,987	<b>Demand</b>	5.756%
	210,611,539	13,121,520	Variable	20,220,356	1,259,769	<b>Energy</b>	6.230%
	42,632,106	2,453,861	Transmission	59,918,260	3,448,835	<b>Demand</b>	5.756%
<b>Electric Total</b>	448,868,086	26,835,329		125,344,178	7,310,591		

**Gas SCADA Agreement**

SCADA	98,213	17,714
-------	--------	--------



2302 Great Northern Drive  
P O Box 2747  
Fargo, ND 58108-2747  
(701) 241-8632  
dave.sederquist@xcelenergy.com

May 9, 2012

Darrell Nitschke, Executive Secretary  
North Dakota Public Service Commission  
State Capitol Building, Dept. 408  
600 East Boulevard  
Bismarck, ND 58505-0480

Re: 2011 REPORT OF REGULATED EARNINGS FOR XCEL ENERGY'S  
NORTH DAKOTA ELECTRIC OPERATIONS

Dear Mr. Nitschke:

Enclosed are eight bound copies of Xcel Energy's Annual Report of 2011 regulated electric earnings in North Dakota. An electronic version of this report was emailed to you today as well.

Our natural gas earnings report is undergoing further review to ensure its accuracy. We have notified staff that we hope to have it completed and filed next week.

Please contact me if you have any questions or comments.

Sincerely,

A handwritten signature in cursive script that reads 'David H. Sederquist'.

DAVID H. SEDERQUIST  
SR. CONSULTANT, REGULATION/FINANCE

Enclosures

**ANNUAL REPORT**

**OF**

**NORTHERN STATES POWER COMPANY,  
A MINNESOTA CORPORATION**

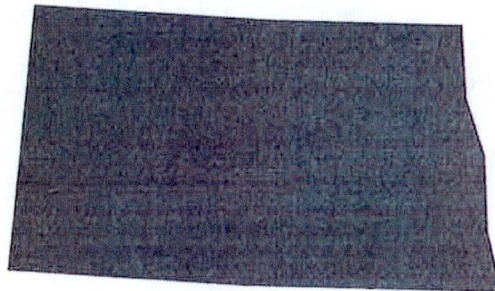
**TO THE**

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

**FOR THE YEAR ENDING**

**DECEMBER 31, 2011**

**North Dakota Jurisdiction**  
Electric Utility



**Filed May 9, 2012**

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**Northern States Power Company  
Electric Utility - North Dakota**

(Dollars In Thousands)

**I. RETURN ON EQUITY (ROE)**

<b><u>Actual Return on Equity (ROE)<sup>1</sup></u></b>	<b><u>2011</u></b>	<b><u>2010</u></b>
1 Operating Income from Electric Operations (E-2):	\$24,952	\$11,664
2 Average Regulated Rate Base (E-3):	\$322,995	\$282,316
3 Rate of Return on Rate Base (ROR) (line 1 / line 2):	7.73%	4.13%
4 Weighted Cost of Debt (E-4):	2.88%	2.99%
5 Weighted Cost of Preferred Stock (E-4):	0.00%	0.00%
6 % of Equity in Capital Structure (E-4):	52.67%	51.99%
7 Return on Equity (ROE):	9.20%	2.20%

<b><u>ROE, Normalized for Weather Impact on Sales<sup>1</sup></u></b>	<b><u>2011</u></b>	<b><u>2010</u></b>
8 Operating Income from Electric Operations:	\$24,952	\$11,664
9 Impact of weather on Mwh Sales:	9,730	(2,517)
10 Impact of weather on Electric Operating Income :	\$254	\$2
11 Weather-Normalized Operating Income:	\$24,698	\$11,662
12 Average Regulated Rate Base:	\$322,995	\$282,316
13 Weather-Normal Rate of Return on Rate Base (ROR):	7.65%	4.13%
14 Weather-Normalized Return on Equity (ROE):	9.05%	2.19%

## Northern States Power Company Electric Utility - North Dakota

(Dollars In Thousands)

### II. OPERATING INCOME

<u>Line</u>	<u>Item</u>	<u>2011</u> <u>Total NSP</u>	<u>2011</u> <u>N.D. Juris.</u>	<u>N. D. %</u>	<u>2010</u> <u>N.D. Juris.</u>	<u>Annual</u> <u>Change</u>
<b><u>Operating Revenues:</u></b>						
1	Residential	1,142,370	68,744	5.4%	61,131	12.5%
2	Small Comm. & Ind.	1,273,405	83,167	5.7%	72,918	14.1%
3	Large Comm. & Ind.	661,865	21,516	2.9%	19,074	12.8%
4	Public Street & Highway Ltg	25,590	1,616	5.7%	1,452	11.3%
5	Other Sales to Publ Auth	<u>8,665</u>	<u>1,246</u>	<u>12.7%</u>	<u>1,097</u>	<u>13.6%</u>
	Total Retail	3,111,896	176,290	5.0%	155,671	13.2%
6	Interdepartmental	548	0	0.0%	0	*
7	Sales for Resale	74,745	4,497	15.1%	11,295	-60.2%
8	Interchange Agreement	440,519	26,283	5.5%	24,210	8.6%
9	Other	118,333	6,814	4.8%	5,644	20.7%
10	Total Revenues:	<u>3,746,042</u>	<u>213,884</u>	<u>5.7%</u>	<u>196,820</u>	<u>8.7%</u>
<b><u>Operating Expenses:</u></b>						
11	Fuel & Purchased Energy	1,228,707	76,040	6.2%	86,548	-12.1%
12	Production	740,713	43,220	5.8%	40,558	6.6%
13	Transmission	195,079	11,219	5.8%	9,725	15.4%
14	Distribution	112,987	6,737	6.0%	5,779	16.6%
15	Customer Billing	59,289	4,411	7.4%	4,394	0.4%
16	Customer Service	115,749	489	0.4%	262	86.6%
17	Sales & Marketing	254	135	53.1%	151	-10.6%
18	Admin. & General	189,822	11,770	6.2%	12,374	-4.9%
19	Depreciation & Amortization	346,369	17,885	5.2%	15,981	11.9%
20	Property Taxes	123,651	5,881	4.8%	5,585	5.3%
21	Payroll & Other Taxes	30,956	1,820	5.9%	1,731	5.1%
22	Income Taxes	(189)	(1,111)	587.8%	0	*
23	Deferred Income Taxes & ITC	156,485	10,436	6.7%	2,068	404.6%
24	Total Expenses:	<u>3,299,872</u>	<u>188,932</u>	<u>5.7%</u>	<u>185,156</u>	<u>2.0%</u>
25	Regulated Operating Income	<u>446,170</u>	<u>24,952</u>	<u>5.6%</u>	<u>11,664</u>	<u>113.9%</u>

**Northern States Power Company  
Electric Utility - North Dakota**

(Dollars In Thousands)

**III. AVERAGE RATE BASE**

<u>Line</u>	<u>Item</u>	<u>2011 Total NSP</u>	<u>2011 N.D. Juris.</u>	<u>N. D. %</u>	<u>2010 N.D. Juris.</u>	<u>Annual Change</u>
1	Plant in Service	13,666,833	742,545	5.4%	673,626	10.2%
2	Accumulated Depreciation	6,539,914	364,662	5.6%	339,921	7.3%
3	Net Plant in Service	7,126,919	377,883	5.3%	333,705	13.2%
4	Plant Held for Future Use	0	0	*	0	*
5	Construct Work in Progress	10,012	657	6.6%	900	-27.0%
6	Materials and Supplies	124,370	7,213	5.8%	6,283	14.8%
7	Fuel Stocks	87,684	5,454	6.2%	5,234	4.2%
8	Prepayments & Other Rate Base	59,821	3,833	6.4%	4,379	-12.5%
9	Customer Deposits	(1,974)	(15)	0.8%	(166)	-91.0%
10	Cash Working Capital	0	0	*	0	*
11	Other Rate Base <sup>1</sup>	(65,643)	(3,903)	5.9%	(6,232)	-37.4%
12	Accum. Deferred Taxes	(1,380,354)	(68,127)	4.9%	(61,787)	10.3%
13	Total Other Rate Base	(1,166,084)	(54,888)	4.7%	(51,389)	6.8%
14	Total Average Rate Base	5,960,835	322,995	5.4%	282,316	14.4%

<sup>1</sup> Includes deferred assets and liabilities such as accrued vacations, post-retirement medical benefits (FASB 106), post employment benefits (FASB 112), unfunded pension liability, environmental cleanup, severance accrual, etc.

## Northern States Power Company Electric Utility - North Dakota

(Dollars In Thousands)

### IV. COST OF CAPITAL

<u>2011 Actual</u>					
<u>Line</u>	<u>Item</u>	<u>Amount</u>	<u>% of Total</u>	<u>Cost</u>	<u>Weighted Cost</u>
1	Long-Term Debt	\$3,286,351	46.90%	6.12%	2.87%
2	Short-Term Debt	<u>\$30,167</u>	<u>0.43%</u>	<u>3.06%</u>	<u>0.01%</u>
3	Total Debt	\$3,316,518	47.33%	6.09%	2.88%
4	Preferred Stock	\$0	0.00%	0.00%	0.00%
5	Common Equity	<u>\$3,690,284</u>	<u>52.67%</u>	<u>9.20%</u>	<u>4.85%</u>
6	Total Equity	\$3,690,284	52.67%		
7	Total Capital	\$7,006,802	100.00%		7.73%

<u>2010 Normalized</u>					
<u>Line</u>	<u>Item</u>	<u>Amount</u>	<u>% of Total</u>	<u>Cost</u>	<u>Weighted Cost</u>
8	Long-Term Debt	\$3,286,351	46.90%	6.12%	2.87%
9	Short-Term Debt	<u>\$30,167</u>	<u>0.43%</u>	<u>3.06%</u>	<u>0.01%</u>
10	Total Debt	3,316,518	47.33%	6.09%	2.88%
11	Preferred Stock	\$0	0.00%		0.00%
12	Common Equity	<u>\$3,690,284</u>	<u>52.67%</u>	<u>9.05%</u>	<u>4.76%</u>
13	Total Equity	\$3,690,284	52.67%		
14	Total Capital	\$7,006,802	100.00%		7.65%

**Xcel Energy  
Electric Utility - State of North Dakota  
Reliability Performance - Overall ND System  
2007 - 2011 Results - Normalized**

**System Average Interruption Frequency Index (SAIFI)**

(Average # of interruptions per customer)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011 YTD	0.05	0.28	0.31	0.44	0.48	0.77	0.83	0.90	1.01	1.07	1.11	1.13
2010 YTD	0.03	0.05	0.11	0.27	0.40	0.52	0.66	0.85	0.91	1.17	1.18	1.20
2009 YTD	0.01	0.02	0.08	0.08	0.22	0.29	0.41	0.50	0.56	0.59	0.61	0.68
2008 YTD	0.07	0.08	0.12	0.13	0.20	0.42	0.51	0.57	0.60	0.63	0.65	0.67
2007 YTD	0.01	0.12	0.20	0.24	0.30	0.39	0.46	0.57	0.60	0.70	0.83	0.89
5 year average:												0.91

**Customer Average Interruption Duration Index (CAIDI)**

(Average # of minutes per interruption per customer)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011 YTD	109.0	320.6	295.0	230.1	217.7	157.9	156.0	155.3	148.5	143.0	141.0	140.6
2010 YTD	62.3	75.4	76.6	65.6	75.5	68.3	70.3	64.0	65.3	59.4	59.6	62.8
2009 YTD	141.4	108.1	92.6	98.6	74.1	78.0	81.0	90.8	87.1	89.6	90.4	91.5
2008 YTD	87.7	86.7	74.5	78.0	75.7	85.7	88.1	92.2	94.4	95.4	94.6	95.6
2007 YTD	79.2	110.9	106.5	102.8	94.1	97.6	93.8	91.9	93.1	85.4	77.6	77.6
5 year average:												93.6

**Xcel Energy**  
**Electric Utility - State of North Dakota**  
**Reliability Performance - 5 Largest Substations**  
**2007 - 2011 Results - Normalized**

**System Average Interruption Frequency Index (SAIFI)**  
(Average # of interruptions per customer)

	<b>Cass County Sub (Fgo)</b>	<b>Red River Sub (Fgo)</b>	<b>Gateway Sub (GF)</b>	<b>Nordic Sub (GF)</b>	<b>Souris Sub (Minot)</b>
2011	1.80	1.13	0.81	0.69	1.00
2010	0.46	1.68	0.68	2.27	0.29
2009	0.72	0.96	0.19	0.55	0.49
2008	0.34	0.88	0.67	0.57	0.58
2007	0.29	1.12	2.36	0.25	0.72
5 year average:	0.72	1.15	0.94	0.86	0.62

**Customer Average Interruption Duration Index (CAIDI)**  
(Average # of minutes per interruption per customer)

	<b>Cass County Sub (Fgo)</b>	<b>Red River Sub (Fgo)</b>	<b>Gateway Sub (GF)</b>	<b>Nordic Sub (GF)</b>	<b>Souris Sub (Minot)</b>
2011	342.0	86.3	100.7	83.7	69.4
2010	127.1	58.2	44.3	61.9	76.5
2009	87.6	87.8	96.0	86.9	58.0
2008	143.2	96.7	100.6	85.4	62.8
2007	126.3	78.0	76.2	96.5	63.4
5 year average:	165.23	81.39	83.54	82.88	66.04

Xcel Energy  
Electric Utility – State of North Dakota  
2012 Reliability Plan Summary

**Overhead Line Upgrades - \$324,000**

Xcel Energy's 2012 capital budget includes about \$324,000 to upgrade its electric overhead system in North Dakota. These improvements include replacing failed devices, installing upgrades necessary to the backbone system to serve new customers, and installing upgrades necessary to solve reliability issues. Included in this effort is funding for our Reliability Exception Monitoring System ("REMS") program. Generally, this computer-based system initiates an investigation by flagging any device that has tripped more than twice in a rolling 12 month period. Following an engineering review, corrective actions are identified and implemented where appropriate.

**Distribution Pole Testing - \$251,000**

Xcel Energy's 2012 pole replacement plan includes an operating and maintenance expense budget of \$251,000 for testing wood distribution poles in North Dakota. The testing methodology conforms to a scientific procedure that is utilized throughout the industry. It includes a visual check and test of remaining pole strength. If a pole is identified as having strength characteristics below acceptable standards, the pole is scheduled for replacement or reinforcement. The expense budget for this program is subject to ongoing adjustments based on the Company's overall financial situation throughout the plan year.

**Underground Cable Upgrade - \$211,000**

In 2012, Xcel Energy plans to spend about \$211,000 in capital funds to upgrade its underground cable system in North Dakota. A little over half of these expenditures will include replacing cables that have failed but are not fit to be repaired and returned to service. They also include cables that may have experienced multiple failures in the past but for which repairs still present a viable remedy. Projects will involve the installation of additional backbone system capacity to serve new load or relieve load on existing facilities.

In addition, beginning in 2012, Xcel Energy will embark on a 3 year effort to proactively locate and remove non-standard 500 MCM cable remaining on our system. This project reflects one of several Settlement commitments in our most recent electric rate case (PU-10-657 and PU-11-55). The company plans to spend about \$102,000 in 2012 on this project.

## Northern States Power Company Supporting Information - North Dakota

### I. Sales and Customer Data

#### Electric Utility (N. D. Jurisdiction)

<u>Line</u>	<u>Customers (@ Dec)</u>	<u>2011</u>	<u>2010</u>	<u>2009</u>	<u>2008</u>	<u>2007</u>
1	Residential	76,126	76,319	75,608	75,036	74,094
2	Small C & I	12,033	12,078	11,989	11,895	11,821
3	Large C & I	20	20	19	22	21
4	PSHL/OSPA	<u>280</u>	<u>284</u>	<u>283</u>	<u>280</u>	<u>273</u>
5	Total Retail	88,459	88,701	87,899	87,233	86,209
<u>Line</u>	<u>Mwh Sales</u>	<u>2011</u>	<u>2010</u>	<u>2009</u>	<u>2008</u>	<u>2007</u>
6	Residential	776,125	769,024	794,420	761,934	761,356
7	Small C & I	1,085,821	1,057,747	1,116,612	1,093,952	1,067,116
8	Large C & I	350,764	349,581	310,239	328,203	358,129
9	PSHL/OSPA	<u>29,790</u>	<u>29,528</u>	<u>25,354</u>	<u>26,057</u>	<u>26,858</u>
10	Total Retail	2,242,500	2,205,880	2,246,625	2,210,146	2,213,459
11	Ave. ¢/Kwh	7.86	7.06	7.10	7.33	6.59
12	Ave. Res. Monthly Usage (kwh)	850	840	876	846	856
13	Ave. Res. Monthly Bill	\$75.25	\$66.75	\$69.96	\$69.19	\$62.40

**Xcel Energy**  
**Supporting Information - North Dakota**  
**II. AFFILIATED TRANSACTIONS Summary**

Line #	Affiliate Name	General Description of Services Rendered &/or Supplied	Portion Allocated to North Dakota Jurisdiction Electric and Gas Totals (1)	
			Expense (2)	Revenue (3)
1	Northern States Power Company (Wis.)	Electric and Gas Utility	7,276,846	26,320,435
2	Public Service of Colorado	Electric and Gas Utility	2,849	16,814
3	Southwestern Public Service	Electric Utility	1,714	4,427
4	United Power and Land	Real estate holdings	-	-
5	Eloigne Company	Affordable housing investment program	-	-
6	Xcel Energy Services	Xcel Energy Inc. service company	16,420,741	-
7	e'Prime	Engineering services	-	-

Notes:

- (1) The amounts allocated to North Dakota electric and gas jurisdictions represent an estimate based on an overall allocation factor applied to all of the revenues and expenses for each affiliate. To derive the actual amounts by jurisdiction would require an allocation by transaction by account number and would require significant analysis and expense to perform.
- (2) Expense to North Dakota electric and gas jurisdictions. Revenue to affiliate for services provided to NSP (Mn).
- (3) Revenue to North Dakota electric and gas jurisdictions. Expense to the affiliate for services provided to the affiliate by NSP (MN).

**Xcel Energy**  
**Supporting Information - North Dakota**  
**III. Affiliated Transactions Summary**

	<u>Total Expense</u>	<u>Total Revenue</u>	<u>Elec %</u>	<u>Gas %</u>	<u>(Customers) ND Elec%</u>	<u>(Customers) ND Gas%</u>	<u>Allocation Used (1)</u>
NSP Wis.	538,857	1,374,186	92.8654%	7.1346%	6.2805%	9.8133%	Common
PSCo	45,368	267,718	100.0%	0.0%	6.2805%	0.0%	Electric
SPS	27,288	70,492	100.0%	0.0%	6.2805%	0.0%	Electric
UP&L	-	-	92.8654%	7.1346%	6.2805%	9.8133%	Common
Eloigne	-	-	92.8654%	7.1346%	6.2805%	9.8133%	Common
XES	251,367,962	-	92.8654%	7.1346%	6.2805%	9.8133%	Common
ePrime	-	-	100.0%	0.0%	6.2805%	0.0%	Electric
	<b>251,979,475</b>	<b>1,712,396</b>					

**(1) Allocation of Revenues & Expenses between NSP Minnesota and Affiliates**

Common Allocation Methodology is Labor	<u>Electric</u>	<u>Gas</u>	<u>Load Dispatch</u>	
Utility Labor Allocator	92.8654%	7.1346%	<u>Design Day</u>	10.5580%
Customers North Dakota Jurisdictional	6.2805%	9.8133%		10.5613%
Factor Formula: ((Util Elec)*ND Jur Ele)+((Util Gas)*ND Jur Gas) =				6.5326%

**(2) Affiliated Transactions between Minnesota and Wisconsin**

	<u>Total</u>	<u>ND Alloc.</u>		<u>Total</u>	<u>ND Alloc.</u>	<u>Alloc. Method</u>	<u>ND Alloc %</u>
<b>Electric Inter change Agreement dollars</b>				<b>Expenses</b>			
<b>Revenues</b>	195,939,717	11,268,689	Fixed	48,949,521	2,815,136	<b>Demand</b>	5.751%
	202,288,680	12,582,154	Variable	19,429,562	1,208,499	<b>Energy</b>	6.220%
	41,200,349	2,369,473	Transmission	55,954,687	3,218,010	<b>Demand</b>	5.751%
<b>Electric Total</b>	<b>439,428,745</b>	<b>26,220,316</b>		<b>124,333,770</b>	<b>7,241,645</b>		
<b>Gas SCADA Agreement</b>							
SCADA	98,031	10,350					



2302 Great Northern Drive  
P O Box 2747  
Fargo, ND 58108-2747  
(701) 241-8632  
dave.sederquist@xcelenergy.com

May 9, 2011

**RECEIVED**

Darrell Nitschke, Executive Secretary  
North Dakota Public Service Commission  
State Capitol Building, Dept. 408  
600 East Boulevard  
Bismarck, ND 58505-0480

MAY 06 2011

**PUBLIC SERVICE COMMISSION**

Re: 2010 REPORT OF REGULATED EARNINGS FOR XCEL ENERGY'S  
NORTH DAKOTA ELECTRIC AND NATURAL GAS OPERATIONS

Dear Mr. Nitschke:

Enclosed are eight bound copies of Xcel Energy's Annual Report of 2010 regulated electric and natural gas earnings in North Dakota. An electronic version of this report was emailed on May 6 as well.

Please contact me if you have any questions or comments.

Sincerely,

DAVID H. SEDERQUIST  
SR. CONSULTANT, REGULATION/FINANCE

Enclosures

1 PU-11-147 Filed: 5/6/2011 Pages: 13  
2010 report of regulated electric earnings - North  
Dakota

Northern States Power Company  
David Sederquist, Sr. Consultant

**ANNUAL REPORT**  
**OF**  
**NORTHERN STATES POWER COMPANY,**  
**A MINNESOTA CORPORATION**  
**TO THE**  
**NORTH DAKOTA PUBLIC SERVICE COMMISSION**  
**FOR THE YEAR ENDING**  
**DECEMBER 31, 2010**

**North Dakota Jurisdiction**  
Electric and Natural Gas Utilities



**2010**

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**Northern States Power Company**  
**Electric Utility - North Dakota**  
(Dollars In Thousands)

**I. RETURN ON EQUITY (ROE)**

<u>Actual Return on Equity (ROE)<sup>1</sup></u>	<u>2010</u>	<u>2009</u>
1 Operating Income from Electric Operations (E-2):	\$11,664	\$21,709
2 Average Regulated Rate Base (E-3):	\$282,316	\$264,909
3 Rate of Return on Rate Base (ROR) (line 1 / line 2):	4.13%	8.19%
4 Weighted Cost of Debt (E-4):	2.99%	3.06%
5 Weighted Cost of Preferred Stock (E-4):	0.00%	0.00%
6 % of Equity in Capital Structure (E-4):	51.99%	52.23%
7 Return on Equity (ROE):	2.20%	9.83%

<u>ROE, Normalized for Weather Impact on Sales<sup>1</sup></u>	<u>2010</u>	<u>2009</u>
8 Operating Income from Electric Operations:	\$11,664	\$21,709
9 Impact of weather on Mwh Sales:	(2,517)	7,352
10 Impact of weather on Electric Operating Income :	\$2	(\$456)
11 Weather-Normalized Operating Income:	\$11,662	\$22,165
12 Average Regulated Rate Base:	\$282,316	\$264,909
13 Weather-Normal Rate of Return on Rate Base (ROR):	4.13%	8.37%
14 Weather-Normalized Return on Equity (ROE):	2.19%	10.16%

<sup>1</sup> Reported Actual and weather-normalized Returns on Equity (ROE) reflect a one time deferred fuel expense write-off of \$11,125,000. Adjusting for this item would result in an actual ROE of 6.81%.

**Northern States Power Company**  
**Electric Utility - North Dakota**  
(Dollars In Thousands)

**II. OPERATING INCOME**

<u>Line Item</u>	<u>2010 Total NSP</u>	<u>2010 N.D. Juris.</u>	<u>N. D. %</u>	<u>2009 N.D. Juris.</u>	<u>Annual Change</u>
<b><u>Operating Revenues:</u></b>					
1 Residential	1,091,313	61,131	5.8%	63,471	-3.7%
2 Small Comm. & Ind.	1,234,448	72,918	6.2%	76,388	-4.5%
3 Large Comm. & Ind.	624,462	19,074	2.8%	17,424	9.5%
4 Public Street & Highway Ltg	24,748	1,452	5.9%	1,453	-0.1%
5 Other Sales to Publ Auth	<u>8,458</u>	<u>1,097</u>	<u>9.9%</u>	<u>838</u>	<u>30.8%</u>
Total Retail	2,983,429	155,671	5.3%	159,574	-2.4%
6 Interdepartmental	417	0	0.0%	0	*
7 Sales for Resale	204,835	11,295	4.0%	8,155	38.5%
8 Interchange Agreement	416,076	24,210	5.5%	22,941	5.5%
9 Other	<u>103,265</u>	<u>5,644</u>	<u>5.6%</u>	<u>5,745</u>	<u>-1.8%</u>
10 Total Revenues:	<u>3,708,022</u>	<u>196,820</u>	5.3%	196,416	0.2%
<b><u>Operating Expenses:</u></b>					
11 Fuel & Purchased Energy	1,328,234	86,548	6.5%	72,993	18.6%
12 Production	717,081	40,558	5.7%	38,429	5.5%
13 Transmission	174,351	9,725	5.6%	9,301	4.6%
14 Distribution	109,899	5,779	5.3%	5,612	3.0%
15 Customer Billing	58,762	4,394	7.5%	4,583	-4.1%
16 Customer Service	79,140	262	0.3%	280	-6.4%
17 Sales & Marketing	332	151	45.5%	50	202.0%
18 Admin. & General	203,310	12,374	6.1%	12,070	2.5%
19 Depreciation & Amortization	331,995	15,981	4.8%	14,892	7.3%
20 Property Taxes	116,166	5,585	4.8%	5,065	10.3%
21 Payroll & Other Taxes	29,044	1,731	6.0%	1,743	-0.7%
22 Income Taxes	(915)	0	0.0%	1,727	-100.0%
23 Deferred Income Taxes & ITC	<u>138,424</u>	<u>2,068</u>	<u>1.5%</u>	<u>7,962</u>	<u>-74.0%</u>
24 Total Expenses:	<u>3,285,823</u>	<u>185,156</u>	5.6%	174,707	6.0%
25 Regulated Operating Income	422,199	11,664	2.8%	21,709	-46.3%

**Northern States Power Company**  
**Electric Utility - North Dakota**  
(Dollars In Thousands)

**III. AVERAGE RATE BASE**

<u>Line</u>	<u>Item</u>	2010		<u>N. D. %</u>	2009		<u>Annual Change</u>
		<u>Total NSP</u>	<u>N.D. Juris.</u>		<u>N.D. Juris.</u>		
1	Plant in Service	12,722,342	673,626	5.3%	636,654		5.8%
2	Accumulated Depreciation	<u>6,245,875</u>	<u>339,921</u>	<u>5.4%</u>	<u>332,388</u>		<u>2.3%</u>
3	Net Plant in Service	6,476,467	333,705	5.2%	304,266		9.7%
4	Plant Held for Future Use	0	0	*	0		*
5	Construct Work in Progress	16,425	900	5.5%	8,224		-89.1%
6	Materials and Supplies	111,130	6,283	5.7%	5,770		8.9%
7	Fuel Stocks	86,048	5,234	6.1%	6,119		-14.5%
8	Prepayments & Other Rate Base	64,841	4,379	6.8%	3,771		16.1%
9	Customer Deposits	(2,617)	(166)	6.3%	(108)		53.7%
10	Cash Working Capital	0	0	*	0		*
11	Other Rate Base <sup>1</sup>	(107,540)	(6,232)	5.8%	(7,157)		-12.9%
12	Accum. Deferred Taxes	<u>(1,220,754)</u>	<u>(61,787)</u>	<u>5.1%</u>	<u>(55,976)</u>		<u>10.4%</u>
13	Total Other Rate Base	(1,052,467)	(51,389)	4.9%	(39,357)		30.6%
14	Total Average Rate Base	5,424,000	282,316	5.2%	264,909		6.6%

<sup>1</sup> Includes deferred assets and liabilities such as accrued vacations, post-retirement medical benefits (FASB 106), post employment benefits (FASB 112), unfunded pension liability, environmental cleanup, severance accrual, etc.

**Northern States Power Company**  
**Electric Utility - North Dakota**  
(Dollars In Thousands)

**IV. COST OF CAPITAL**

<u>2010 Actual</u>					
<u>Line</u>	<u>Item</u>	<u>Amount</u>	<u>% of Total</u>	<u>Cost</u>	<u>Weighted Cost</u>
1	Long-Term Debt	\$3,097,147	47.24%	6.31%	2.98%
2	Short-Term Debt	<u>\$50,250</u>	<u>0.77%</u>	<u>0.92%</u>	<u>0.01%</u>
3	Total Debt	\$3,147,397	48.01%	6.22%	2.99%
4	Preferred Stock	\$0	0.00%	0.00%	0.00%
5	Common Equity	<u>\$3,408,561</u>	<u>51.99%</u>	2.20%	1.14%
6	Total Equity	\$3,408,561	51.99%		
7	Total Capital	\$6,555,958	100.00%		4.13%

<u>2010 Normalized</u>					
<u>Line</u>	<u>Item</u>	<u>Amount</u>	<u>% of Total</u>	<u>Cost</u>	<u>Weighted Cost</u>
8	Long-Term Debt	\$3,097,147	47.24%	6.31%	2.98%
9	Short-Term Debt	<u>\$50,250</u>	<u>0.77%</u>	<u>0.92%</u>	<u>0.01%</u>
10	Total Debt	3,147,397	48.01%	6.22%	2.99%
11	Preferred Stock	\$0	0.00%		0.00%
12	Common Equity	<u>\$3,408,561</u>	<u>51.99%</u>	2.19%	1.14%
13	Total Equity	\$3,408,561	51.99%		
14	Total Capital	\$6,555,958	100.00%		4.13%

**Northern States Power Company  
Electric Utility - State of North Dakota  
Reliability Performance - Overall ND System  
2010 Results - Normalized**

System Average Interruption Frequency Index (SAIFI)

(Average # of interruptions per customer)

YTD	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2010	0.03	0.05	0.11	0.27	0.40	0.52	0.66	0.85	0.91	1.17	1.18	1.20
2009	0.01	0.02	0.08	0.08	0.22	0.29	0.41	0.50	0.56	0.59	0.61	0.68
2008	0.07	0.08	0.12	0.13	0.20	0.42	0.51	0.57	0.60	0.63	0.65	0.67
2007	0.01	0.12	0.20	0.24	0.30	0.39	0.46	0.57	0.60	0.70	0.83	0.89
2006	0.03	0.13	0.20	0.22	0.27	0.35	0.47	0.52	0.57	0.59	0.61	0.62
10 yr average:												0.81

Customer Average Interruption Duration Index (CAIDI)

(Average # of minutes per interruption per customer)

YTD	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2010	62.31	75.37	76.59	65.55	75.47	68.26	70.26	64.04	65.33	59.37	59.60	62.81
2009	141.42	108.13	92.63	98.62	74.15	77.99	80.97	90.76	87.11	89.57	90.36	91.55
2008	87.71	86.67	74.52	78.01	75.68	85.68	88.08	92.20	94.42	95.44	94.63	95.60
2007	79.15	110.87	106.52	102.84	94.13	97.55	93.78	91.86	93.05	85.42	77.65	77.59
2006	88.27	55.17	68.05	67.34	68.78	69.27	74.42	76.10	75.15	76.72	76.59	76.95
10 yr average:												80.90

**Northern States Power Company  
Electric Utility - State of North Dakota  
Reliability Performance - 5 Largest Substations  
2010 Results - Normalized**

System Average Interruption Frequency Index (SAIFI)  
(Average # of interruptions per customer)

	Cass County Sub (Fgo)	Red River Sub (Fgo)	Gateway Sub (GF)	Nordic Sub (GF)	Souris Sub (Minot)
2010	0.46	1.68	0.68	2.27	0.29
2009	0.72	0.96	0.19	0.55	0.49
2008	0.34	0.88	0.67	0.57	0.58
2007	0.29	1.12	2.36	0.25	0.72
2006	0.36	0.60	1.51	0.37	0.42
5 year average:	0.43	1.05	1.08	0.80	0.50

Customer Average Interruption Duration Index (CAIDI)  
(Average # of minutes per interruption per customer)

	Cass County Sub (Fgo)	Red River Sub (Fgo)	Gateway Sub (GF)	Nordic Sub (GF)	Souris Sub (Minot)
2010	127.11	58.18	44.28	61.94	76.52
2009	87.6	87.8	96.0	86.9	58.0
2008	143.2	96.7	100.6	85.4	62.8
2007	126.3	78.0	76.2	96.5	63.4
2006	123.42	91.46	50.50	96.35	68.84
5 year average:	121.51	82.42	73.51	85.42	65.92

Northern States Power Company  
Electric Utility – State of North Dakota  
2011 Reliability Plan Summary

**Underground Cable Upgrade - \$677,000**

In 2011, Xcel Energy plans to spend about \$677,000 in capital funds to upgrade its underground cable system in North Dakota. These improvements include replacing cables that have failed and are not fit to be repaired and returned to service, as well as cables that may have experienced multiple failures in the past but for which repairs still present a viable remedy. Projects will also involve the installation of additional backbone system capacity to serve new load or relieve load on existing facilities.

**Overhead Upgrade - \$470,000**

Xcel Energy's 2011 capital budget includes about \$470,000 to upgrade its overhead system in North Dakota. These improvements include replacing failed devices, installing upgrades necessary to the backbone system to serve new customers, and installing upgrades necessary to solve reliability issues. Included in this effort is funding for our Reliability Exception Monitoring System ("REMS") program. This system initiates an investigation by flagging when a device has tripped more than twice in a rolling 12 month period. Following an investigation, corrective actions are identified and implemented where appropriate.

**Distribution Pole Testing - \$73,000**

Xcel Energy's 2011 pole replacement plan includes an operating and maintenance expense budget of \$73,000 for testing wood distribution poles in North Dakota. The testing methodology conforms to a scientific procedure that is utilized throughout the industry. It includes a visual check and test of remaining pole strength. If a pole is identified as having strength characteristics below acceptable standards, the pole is scheduled for replacement or reinforcement. The expense budget for this program is subject to ongoing adjustments based on the Company's overall financial situation throughout the plan year.

- Non Public Document – Contains Trade Secret Data  
 Public Document – Trade Secret Data Excised  
 Public Document

Xcel Energy

Case No.: PU-12-813

Response To: North Dakota Public Service Commission      Data Request No.      NDPSC-5-020

Requestor: Snavelly King

Date Received: March 29, 2013

---

Question:

Witness: Anne E. Heuer-Revenue Requirement (Exhibit AEH-1)

Please refer to page 8 of the Heuer Testimony. Are any of the NSP-NDO's capital additions to be placed in service in this rate proceeding greater than \$25 million? If so, please provide a breakdown of the costs, the expected in-service date, and any changes to the initial project cost.

Response:

Please see Attachment A for all capital additions for NSPM for 2012 and 2013. The list is identical to that provided for NDPSC 2-010 with the location information added.

---

Preparer: Michael Bliss  
Title: Accounting Analyst  
Department: Capital Asset Accounting  
Telephone: 612-330-6216  
Date: May 1, 2013

Northern States Power Company  
Electric Utility - State of North Dakota

Case No-12-813  
Data Request NDSPC 5-20  
Attachment A, Page 1 of 46

**Additions by Project  
for NSPM Electric Utility 2012 and 2013  
with Major Location**

Project	Description	Major Location	2012	2013	Grand Total
10006393	Minnesota-Sub Capac Reinforcem	Elec Dist-Sub-MN	425,310	803,267	1,228,576
10006417	Minnesota- Dist Sub Eq Replace	Elec Dist-Sub-MN	1,524,349	2,215,158	3,739,507
10006431	Office & Miscellaneous Buildin	Office, Service & Other Bldgs-MN	(1,001)	-	(1,001)
10006666	Tools & Equipment-Transportati	General Plant-MN	222,351	87,095	309,447
10006686	Spec Cnstr - Sm Tool/Equip	General Plant-MN	110,184	79,720	189,904
10006816	PI-Basic Budget	Elec Prod-Nuclear-MN-Prairie Island	8,039,225	-	8,039,225
10006954	Mpls-New Ug Extension	Elec Dist-Mass-MN	846,856	1,325,075	2,171,930
10006957	Mpls-Ug Conversion/Rebuild	Elec Dist-Mass-MN	1,313,573	1,411,920	2,725,493
10006968	Minnesota-Electric Meter Blank	Elec Dist-Mass-MN	4,420,303	4,234,852	8,655,155
10007058	Mpls-Elec Tool/Equip	General Plant-MN	114,827	109,660	224,487
10007068	Mntka- New Ug Extension	Elec Dist-Mass-MN	326,507	421,983	748,490
10007086	Mntka-Oh Rebuilds	Elec Dist-Mass-MN	495,295	660,862	1,156,158
10007114	Mntka-Elec Tools/Equip	General Plant-MN	25,560	15,137	40,696
10007241	South Dakota - Oh Extension	Elec Dist-Mass-SD	547,287	393,700	940,987
10007278	South Dakota - Oh Rebuilds	Elec Dist-Mass-SD	839,048	668,269	1,507,317
10007315	South Dakota - Tools & Equip	General Plant-SD	90,399	89,023	179,421
10007391	Edina-Ug Extensions	Elec Dist-Mass-MN	341,644	765,280	1,106,924
10007416	Edina-Oh Rebuilds	Elec Dist-Mass-MN	509,296	519,741	1,029,037
10007440	Edina-Elect Tool/Equip	General Plant-MN	23,686	22,641	46,327
10007457	Maple Grv- Elec Ug Extension	Elec Dist-Mass-MN	648,483	874,357	1,522,840
10007463	Minnesota- New Bus Transformer	Elec Dist-Mass-MN	16,936,997	15,761,272	32,698,269
10007487	Maple Grv-Oh Rebuilds	Elec Dist-Mass-MN	446,386	512,155	958,541
10007517	Maple Grv-Elec Tools/Equip	General Plant-MN	37,850	35,531	73,381
10008018	Chi-Lcr 115kv Line	Elec Tran-Line-MN	14,634	-	14,634
10008491	Northwest - Ug Extensions	Elec Dist-Mass-MN	1,003,980	906,667	1,910,647
10008512	Northwest - Overhead Rebuilds	Elec Dist-Mass-MN	652,080	482,041	1,134,121
10008596	Northwest - Elec Tools/Equip	General Plant-MN	116,609	100,359	216,968
10008652	Newport-Elec Tool/Equip	General Plant-MN	21,201	23,138	44,340
10144483	Mpls-Oh Extension	Elec Dist-Mass-MN	170,280	452,024	622,305
10144484	Mpls-Oh Services	Elec Dist-Mass-MN	230,038	341,170	571,208
10144485	Mpls-New Ug Services	Elec Dist-Mass-MN	248,591	192,000	440,591
10144486	Mpls- New Ug Network	Elec Dist-Mass-MN	140,199	267,259	407,458
10144487	Mpls-New Oh Street Lights	Elec Dist-Mass-MN	216,306	230,604	446,910
10144488	Mpls-New Ug Street Lights	Elec Dist-Mass-MN	64,040	166,475	230,514
10144489	Mpls-Elec Non-Refundable Ciac	Elec Dist-Mass-MN	(328,373)	(470,000)	(798,373)
10144490	Mpls-Oh Rebuilds	Elec Dist-Mass-MN	795,409	969,801	1,765,210
10144491	Minnesota- Dist Sub Tool/Equip	General Plant-MN	390,393	556,207	946,601

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10144492	Mpls-Oh Reinforcements	Elec Dist-Mass-MN	80,827	200,834	281,662
10144493	Mpls-Ug Reinforcement	Elec Dist-Mass-MN	53,489	73,143	126,632
10144494	Mpls-Oh Relocations	Elec Dist-Mass-MN	266,795	310,335	577,130
10144495	Mpls-Ug Relocations	Elec Dist-Mass-MN	459,087	565,020	1,024,107
10144497	Mntka-Oh Extension	Elec Dist-Mass-MN	164,909	102,961	267,870
10144498	Mntka-Oh Services	Elec Dist-Mass-MN	26,371	47,660	74,031
10144499	Mntka-New Ug Services	Elec Dist-Mass-MN	323,220	396,000	719,220
10144500	Mntka-New Oh Street Lights	Elec Dist-Mass-MN	28,684	30,357	59,041
10144501	Mntka-New Ug Street Lights	Elec Dist-Mass-MN	31,349	151,226	182,575
10144502	Mntka-Elec Non-Refundable CIAC	Elec Dist-Mass-MN	(205,064)	(221,000)	(426,064)
10144503	Mntka-Ug Conversion/Rebuild	Elec Dist-Mass-MN	486,511	567,206	1,053,717
10144504	Mntka-Oh Reinforcements	Elec Dist-Mass-MN	101,014	67,933	168,948
10144505	Mntka-Ug Reinforcements	Elec Dist-Mass-MN	70,118	20,496	90,614
10144506	Mntka-Oh Relocations	Elec Dist-Mass-MN	338,272	428,429	766,701
10144507	Mntka-Ug Relocations	Elec Dist-Mass-MN	110,197	112,258	222,456
10144509	Edina-Oh Extension	Elec Dist-Mass-MN	28,513	49,247	77,761
10144510	Edina-New Oh Services	Elec Dist-Mass-MN	40,703	55,974	96,677
10144511	Edina-Ug Services	Elec Dist-Mass-MN	140,408	136,000	276,408
10144512	Edina-New Oh Street Lights	Elec Dist-Mass-MN	36,611	28,455	65,065
10144513	Edina-New Ug Street Lights	Elec Dist-Mass-MN	131,588	280,500	412,089
10144514	Edina-Elec Non-Refundable CIAC	Elec Dist-Mass-MN	(111,957)	(102,000)	(213,957)
10144515	Edina-Ug Conversions/Rebuild	Elec Dist-Mass-MN	649,281	790,626	1,439,907
10144516	Edina-Oh Reinforcements	Elec Dist-Mass-MN	18,541	13,900	32,441
10144517	Edina-Ug Reinforcements	Elec Dist-Mass-MN	30,119	66,138	96,257
10144518	Edina-Oh Relocations	Elec Dist-Mass-MN	203,900	307,917	511,817
10144519	Edina-Ug Relocations	Elec Dist-Mass-MN	426,710	387,615	814,325
10144521	White Bear-Oh Extension	Elec Dist-Mass-MN	77,537	192,601	270,138
10144523	White Bear-Oh Services	Elec Dist-Mass-MN	52,004	88,657	140,661
10144525	White Bear-Ug Services	Elec Dist-Mass-MN	686,295	787,000	1,473,295
10144527	White Bear-Oh Street Lights	Elec Dist-Mass-MN	52,277	51,363	103,640
10144528	White Bear-Ug Street Lts	Elec Dist-Mass-MN	445,722	372,436	818,158
10144529	Wb-Elec Non-Refundable Ciac	Elec Dist-Mass-MN	(212,872)	(253,000)	(465,872)
10144530	White Bear-Oh Rebuilds	Elec Dist-Mass-MN	570,906	428,330	999,235
10144531	White Bear-Ug Conv/Rebuilds	Elec Dist-Mass-MN	1,095,328	283,939	1,379,267
10144532	White Bear-Oh Reinforcements	Elec Dist-Mass-MN	121,284	284,283	405,567
10144533	White Bear-Ug Reinforcements	Elec Dist-Mass-MN	39,321	81,897	121,219
10144535	White Bear-Ug Relocations	Elec Dist-Mass-MN	99,831	120,580	220,411

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10144536	White Bear-Electric Tools & Eq	General Plant-MN	35,565	25,768	61,332
10144561	Maple Grv-New Oh Street Lights	Elec Dist-Mass-MN	47,374	32,959	80,332
10144563	Maple Grv-Oh Extension	Elec Dist-Mass-MN	124,826	83,013	207,840
10144565	Maple Grv-Oh Services	Elec Dist-Mass-MN	29,238	47,790	77,028
10144566	Maple Grv-New Elec Ug Services	Elec Dist-Mass-MN	294,760	355,000	649,760
10144570	Maple Grv-New Ug Street Lights	Elec Dist-Mass-MN	102,086	186,282	288,369
10144572	Mplgrv-Elec Non-Refundable Cia	Elec Dist-Mass-MN	(210,820)	(140,000)	(350,820)
10144573	Maple Grv-Ug Conversion/Rebuil	Elec Dist-Mass-MN	806,232	874,007	1,680,239
10144574	Maple Grv-Oh Reinforcements	Elec Dist-Mass-MN	13,472	85,548	99,019
10144575	Maple Grv-Ug Reinforcements	Elec Dist-Mass-MN	6,008	17,880	23,889
10144576	Maple Grv-Oh Relocations	Elec Dist-Mass-MN	136,795	271,283	408,078
10144578	Maple Grv-Ug Relocations	Elec Dist-Mass-MN	247,146	290,221	537,368
10144635	Northwest-New Oh Street Lights	Elec Dist-Mass-MN	171,414	101,161	272,575
10144636	Northwest-New Oh Extensions	Elec Dist-Mass-MN	481,742	494,856	976,599
10144637	Northwest-New Oh Services	Elec Dist-Mass-MN	67,997	106,629	174,626
10144638	Northwest-New Ug Services	Elec Dist-Mass-MN	317,260	377,000	694,260
10144640	Northwest-New Ug Street Lights	Elec Dist-Mass-MN	169,961	58,420	228,381
10144641	Nw-Elec Non-Refundable Ciac	Elec Dist-Mass-MN	(175,650)	(227,000)	(402,650)
10144642	Northwest-Ug Conversion/Rebuil	Elec Dist-Mass-MN	65,601	220,088	285,689
10144643	Northwest-Oh Reinforcements	Elec Dist-Mass-MN	105,796	173,988	279,784
10144644	Northwest-Ug Reinforcement	Elec Dist-Mass-MN	3,258	3,872	7,130
10144645	Northwest-Oh Relocations	Elec Dist-Mass-MN	557,481	702,425	1,259,907
10144646	Northwest-Ug Relocations	Elec Dist-Mass-MN	94,245	41,712	135,957
10144700	North Dakota -Oh Extension	Elec Dist-Mass-ND	287,571	298,411	585,982
10144701	North Dakota -Oh Services	Elec Dist-Mass-ND	76,890	104,804	181,694
10144702	North Dakota -Ug Extension	Elec Dist-Mass-ND	640,418	1,146,923	1,787,341
10144703	North Dakota -Ug Services	Elec Dist-Mass-ND	226,588	279,000	505,588
10144704	North Dakota -Oh Street Lights	Elec Dist-Mass-ND	108,198	73,471	181,670
10144706	Nd-Elec Non-Refundable Ciac	Elec Dist-Mass-ND	(213,357)	(418,000)	(631,357)
10144707	North Dakota -Oh Rebuilds	Elec Dist-Mass-ND	296,161	221,696	517,857
10144708	North Dakota -Ug Conv/Rebuilds	Elec Dist-Mass-ND	383,339	205,618	588,957
10144709	North Dakota -Oh Reinforcement	Elec Dist-Mass-ND	30,689	82,268	112,956
10144710	North Dakota -Ug Reinforcement	Elec Dist-Mass-ND	5,435	12,394	17,828
10144711	North Dakota -Oh Relocations	Elec Dist-Mass-ND	32,587	136,955	169,542
10144712	North Dakota -Ug Relocations	Elec Dist-Mass-ND	25,355	54,270	79,625
10144713	North Dakota -Elec Tools & Eq	General Plant-ND	28,545	43,532	72,077
10144748	Newport-Oh Extension	Elec Dist-Mass-MN	90,182	149,529	239,711

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10144749	Newport-Oh Services	Elec Dist-Mass-MN	48,650	39,098	87,749
10144750	Newport-Ug Services	Elec Dist-Mass-MN	610,229	630,000	1,240,229
10144752	Newport-Oh Streetlights	Elec Dist-Mass-MN	30,151	23,796	53,947
10144753	Newport-Ug Streetlights	Elec Dist-Mass-MN	12,668	141,855	154,523
10144754	Npt-Elec Non-Refundable Ciac	Elec Dist-Mass-MN	(252,468)	(248,000)	(500,468)
10144755	Newport-Oh Rebuilds	Elec Dist-Mass-MN	391,920	445,835	837,754
10144756	Newport-Ug Conversions/Rebuild	Elec Dist-Mass-MN	826,226	534,420	1,360,646
10144757	Newport-Oh Reinforcements	Elec Dist-Mass-MN	85,580	168,411	253,991
10144758	Newport-Ug Reinforcements	Elec Dist-Mass-MN	67,374	75,991	143,365
10144759	Newport-Oh Relocations	Elec Dist-Mass-MN	347,058	491,063	838,120
10144760	Newport-Ug Relocations	Elec Dist-Mass-MN	269,644	307,290	576,934
10144771	Southeast-Oh Extension	Elec Dist-Mass-MN	312,261	524,550	836,812
10144772	Southeast-Oh Services	Elec Dist-Mass-MN	88,946	142,286	231,231
10144773	Southeast-Ug Services	Elec Dist-Mass-MN	398,831	454,000	852,831
10144775	Southeast-Oh Streetlights	Elec Dist-Mass-MN	254,373	194,204	448,577
10144776	Southeast-Ug Streetlights	Elec Dist-Mass-MN	72,786	107,773	180,559
10144777	Se-Elec Non-Refundable Ciac	Elec Dist-Mass-MN	(186,471)	(313,000)	(499,471)
10144778	Southeast-Oh Rebuilds	Elec Dist-Mass-MN	1,248,772	1,189,689	2,438,461
10144779	Southeast-Ug Conv/Rebuilds	Elec Dist-Mass-MN	388,009	489,321	877,331
10144780	Southeast-Oh Reinforcements	Elec Dist-Mass-MN	98,527	192,198	290,725
10144781	Southeast-Ug Reinforcements	Elec Dist-Mass-MN	14,749	31,344	46,093
10144782	Southeast-Oh Relocations	Elec Dist-Mass-MN	1,047,366	1,265,947	2,313,312
10144783	Southeast-Ug Relocations	Elec Dist-Mass-MN	187,255	161,978	349,232
10144784	Southeast-Elec Tools & Equip	General Plant-MN	66,913	80,325	147,238
10144795	St Paul-Oh Extension	Elec Dist-Mass-MN	62,843	209,123	271,967
10144796	St Paul-Oh Services	Elec Dist-Mass-MN	125,974	147,416	273,390
10144797	St Paul-Ug Services	Elec Dist-Mass-MN	88,050	39,000	127,050
10144798	St Paul-Ug Network	Elec Dist-Mass-MN	331,583	571,770	903,353
10144799	St Paul-Oh Streetlights	Elec Dist-Mass-MN	78,808	82,083	160,890
10144800	St Paul-Ug Streetlights	Elec Dist-Mass-MN	16,386	9,254	25,640
10144801	St P-Elec Non-Refundable Ciac	Elec Dist-Mass-MN	(179,736)	(188,000)	(367,736)
10144802	St Paul-Oh Rebuilds	Elec Dist-Mass-MN	526,065	668,334	1,194,399
10144803	St Paul-Ug Conversions/Rebuild	Elec Dist-Mass-MN	462,104	628,678	1,090,782
10144804	St Paul-Oh Reinforcements	Elec Dist-Mass-MN	97,342	343,246	440,588
10144805	St Paul-Ug Reinforcements	Elec Dist-Mass-MN	14,588	62,737	77,326
10144806	St Paul-Oh Relocations	Elec Dist-Mass-MN	152,332	224,635	376,966
10144807	St Paul-Ug Relocations	Elec Dist-Mass-MN	65,781	78,282	144,063

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10144808	St Paul-Elec Tools & Equip	General Plant-MN	25,069	21,957	47,026
10145065	Newport-Ug Extensions	Elec Dist-Mass-MN	854,103	1,534,599	2,388,703
10145070	Southeast-Ug Extensions	Elec Dist-Mass-MN	784,994	1,168,925	1,953,919
10145179	St Paul-Ug Extensions	Elec Dist-Mass-MN	493,732	943,007	1,436,738
10145833	White Bear Ug Extensions	Elec Dist-Mass-MN	526,112	950,802	1,476,914
10145962	South Dakota - Oh Service	Elec Dist-Mass-SD	108,677	81,952	190,629
10145964	South Dakota - Ug Extension	Elec Dist-Mass-SD	1,684,394	2,224,296	3,908,690
10145966	South Dakota - Ug Service	Elec Dist-Mass-SD	580,509	560,000	1,140,509
10145970	South Dakota - Oh Streetlights	Elec Dist-Mass-SD	117,031	64,426	181,456
10145972	South Dakota - Ug Streetlights	Elec Dist-Mass-SD	66,601	28,258	94,859
10145974	Sd-Elec Non-Refundable Ciac	Elec Dist-Mass-SD	(229,817)	(275,000)	(504,817)
10145976	South Dakota - Ug Conv/Rebid	Elec Dist-Mass-SD	613,514	408,608	1,022,122
10145978	South Dakota - Oh Reinforcemnt	Elec Dist-Mass-SD	63,716	430,940	494,656
10145982	South Dakota - Oh Relocations	Elec Dist-Mass-SD	328,017	435,471	763,487
10145984	South Dakota - Ug Relocations	Elec Dist-Mass-SD	113,847	136,937	250,784
10146153	White Bear Oh Relocations	Elec Dist-Mass-MN	407,554	581,061	988,615
10229363	Nspm Metering Sys-Tools & Equi	General Plant-MN	148,221	128,873	277,095
10229574	Nspm-Fdr Cable Replacement-Eme	Elec Dist-Mass-MN	3,350,447	3,716,042	7,066,489
10229647	NSPM-Poor Perf Fdr Replace Blk	Elec Dist-Mass-MN	253,157	1,964,282	2,217,439
10233671	Mn-Construct Dist Sub Tool & E	General Plant-MN	47,516	46,125	93,641
10245168	Nd-Worst Performing Feeder	Elec Dist-Mass-ND	-	59,109	59,109
10245248	MNGP Ind Spent Fuel Storage Install	Elec Prod-Nuclear-MN-Monticello	(34,236)	-	(34,236)
10245258	MNGP Extended Power Uprate	Elec Prod-Nuclear-MN-Monticello	17,962,103	299,362,304	317,324,407
10268169	Riv Merp - Demolition	Elec Prod-Steam-MN-Riverside	50,398	-	50,398
10311808	SWMN825 SPK to LFJ 345 Transmi	Elec Tran-Line-MN	(445)	-	(445)
10333869	NSPM-Accelerated URD Cable Rep	Elec Dist-Mass-MN	8,037,077	9,918,917	17,955,994
10353573	MN Major Storm Recovery Blanke	Elec Dist-Mass-MN	525,893	949	526,842
10381269	2004 Elec Recon Carryover-NSPM	Elec Dist-Mass-MN	3,303,539	3,838,921	7,142,460
10381285	2004 WAN/LAN Refresh - MN	Office, Service & Other Bldgs-MN	(3,410)	-	(3,410)
10383535	SS Corporate Communications Au	Office, Service & Other Bldgs-MN	225,891	67,661	293,551
10386260	PI-ZE PIPING SYSTEM REPLACEMEN	Elec Prod-Nuclear-MN-Prairie Island	766,604	-	766,604
10386411	MNGP Main Generator Hydrogen P	Elec Prod-Nuclear-MN-Monticello	0	-	0
10386846	PI-LICENSE RENEWAL PROJECT	Elec Prod-Nuclear-MN-Prairie Island	5,839	-	5,839
10387103	MNGP Paperless Recorders	Elec Prod-Nuclear-MN-Monticello	-	6,454,854	6,454,854
10390056	PI-U2 STEAM GENERATOR REPLACE	Elec Prod-Nuclear-MN-Prairie Island	-	285,109,366	285,109,366
10390328	Scrap Sale Credits-MN	Elec Dist-Mass-MN	(930,343)	-	(930,343)
10404795	Mpls-OH to UG Service Conv	Elec Dist-Mass-MN	269,975	189,618	459,593

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10404807	Mntka-OH to UG Service Conv	Elec Dist-Mass-MN	102,344	72,072	174,416
10404810	Edina-OH to UG Service Conv	Elec Dist-Mass-MN	132,582	92,664	225,246
10404812	White Bear-OH to UG Service Co	Elec Dist-Mass-MN	110,054	71,214	181,268
10404815	Maple Grv-OH to UG Service Con	Elec Dist-Mass-MN	39,613	29,172	68,785
10404822	Northwest-OH to UG Service Con	Elec Dist-Mass-MN	28,814	24,024	52,838
10404828	ND-OH to UG Service Conv	Elec Dist-Mass-ND	15,619	9,438	25,057
10404836	Newport-OH to UG Service Conv	Elec Dist-Mass-MN	33,891	24,882	58,773
10404844	Southeast-OH to UG Service Con	Elec Dist-Mass-MN	25,648	18,018	43,666
10404850	St Paul-OH to UG Service Conv	Elec Dist-Mass-MN	174,776	126,126	300,902
10437120	Capitalized Locating Cost-Elec	Elec Dist-Mass-MN	160,603	188,442	349,044
10450425	Clring wo's for credits for CRS bil	Elec Dist-Mass-MN	(1,680,816)	-	(1,680,816)
10494498	SD URD Cable Accel Replacement	Elec Dist-Mass-SD	287,301	149,265	436,567
10494522	ND URD Cable Accel Replacement	Elec Dist-Mass-ND	127,407	145,723	273,129
10506768	WLM1C Grate Bed Replacement	Elec Prod-Steam-MN-Wilmarth	-	233,829	233,829
10508764	GMM0C MN Co Emergent Capital	Elec Prod-Steam-MN-Allen S King	0	0	0
10509766	REW0C - East Cell 1B Construct	Elec Prod-Steam-MN-Red Wing	22,611	-	22,611
10511578	BDS5C Combustor Inspection	Elec Prod-Other-MN-Black Dog	487,972	-	487,972
10511936	BDS0C Reroof 3 & 4 turbine roo	Elec Prod-Steam-MN-Black Dog	1,947	-	1,947
10512686	IVH2C-U2 Turbine Rotor Disc Re	Elec Prod-Other-MN-Inver Hills	(3,398)	-	(3,398)
10516736	Southeast - Elec Tools & Equip	General Plant-MN	38,000	-	38,000
10518337	WLM0C Elevator Replacement	Elec Prod-Steam-MN-Wilmarth	219,371	-	219,371
10518548	WLM0C Landfill Cell 6 and 7A C	Elec Prod-Steam-MN-Wilmarth	318,497	-	318,497
10519682	2004 SD Tran Sub Blanket	Elec Tran-Sub-SD	187	-	187
10522808	Oil bkr replacement (10) - MN	Elec Dist-Sub-MN	(7,486)	-	(7,486)
10522944	Replace 7 CM2 Network Protecto	Elec Dist-Mass-MN	166,495	-	166,495
10522951	Replace Vault Top	Elec Dist-Vault-MN	271,667	1,140,826	1,412,494
10523092	Retire subs in Minnesota	Elec Dist-Sub-MN	24,262	-	24,262
10524252	BDS2C Low voltage bkr's & xfmrs	Elec Prod-Other-MN-Black Dog	11,859	-	11,859
10525688	2005 NSP Tran Line Blanket	Elec Tran-Line-MN	589	-	589
10525696	2005 NSP Tran Sub Blanket Tran	Elec Tran-Sub-MN	73,571	-	73,571
10532360	Mnt Reload 25 (C26)	Elec Prod-Nuclear-MN-Monticello	114	-	114
10532379	PI1 Reload 26 (C27)	Elec Prod-Nuclear-MN-Prairie Island	41,245	-	41,245
10532433	PI-TN-40 Transport License	Elec Prod-Nuclear-MN-Prairie Island	16,096	-	16,096
10557022	Fleet New Unit Purchase El Ops	Transportation Equipment-MN	6,069,612	5,543,641	11,613,253
10557030	Fleet New Unit Purchase Common	Transportation Equipment-MN	427,333	912,570	1,339,903
10593255	Transportation Blanket Elec	General Plant-MN	13,574	1,960	15,534
10610653	REW1C-REPLACE U1 SIDE MEMBRANE WALL	Elec Prod-Steam-MN-Red Wing	-	634,890	634,890

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Project	Description	Major Location	2012	2013	Grand Total
10611071	SHC1C U1 Boiler Arch Padwelde	Elec Prod-Steam-MN-Sherburne	12,753,588	-	12,753,588
10611309	SHCJ Demin System Replacement	Elec Prod-Steam-MN-Sherburne	1,589	-	1,589
10615153	IA Tariff Fund NSP	Elec Tran-Sub-MN	480,991	1,942,424	2,423,415
10622959	2005 MN Tran Line Relocation B	Elec Tran-Line-MN	18,294	-	18,294
10632000	2006 NSP Tran Line Blanket	Elec Tran-Line-MN	(361)	-	(361)
10632001	Terminal Gas Breakers	Elec Tran-Sub-MN	(8)	-	(8)
10632313	Champlin tap to Crooked Lake	Elec Tran-Line-MN	(8,334)	-	(8,334)
10634128	SHCCC U1 U2 Pond 3S	Elec Prod-Steam-MN-Sherburne	(1,542)	-	(1,542)
10634307	SHCCC Yard Rail Replacements 2	Elec Prod-Steam-MN-Sherburne	275,166	-	275,166
10634372	Replace Burnside #1 to 28 MVA	Elec Dist-Sub-MN	4	-	4
10636591	PI2 Reload 26 (C27)	Elec Prod-Nuclear-MN-Prairie Island	25,277,481	-	25,277,481
10636915	PI-Foxboro H-Line Protection Repl	Elec Prod-Nuclear-MN-Prairie Island	-	7,057,736	7,057,736
10637181	WLM0C Scalping Conveyor Replac	Elec Prod-Steam-MN-Wilmarth	-	675,802	675,802
10637236	SHCJC Coal Yard Computer	Elec Prod-Steam-MN-Sherburne	4,451	-	4,451
10637366	HNI0C-3 Headgates and Hoists R	Elec Prod-Hydro-MN-Hennepin ISD	-	1,579,463	1,579,463
10637380	SHC1C Replace Condensor Exhaus	Elec Prod-Steam-MN-Sherburne	-	983,795	983,795
10637389	SHC2C Replace Condensor Exhaus	Elec Prod-Steam-MN-Sherburne	-	703,359	703,359
10637406	SHCCC Site Replace Asphalt	Elec Prod-Steam-MN-Sherburne	-	329,620	329,620
10637411	SHCJC Misc Mobile Equipment Re	General Plant-MN	-	66,162	66,162
10673530	2005 ND Tran Sub Blanket	Elec Tran-Sub-ND	12,037	-	12,037
10692281	NSPM Communication Equip-Dist Subs	Elec Dist-Sub-MN	778,575	461,588	1,240,164
10716803	Replace Transformer Cooling at	Elec Dist-Sub-MN	6	-	6
10735790	MNGP 2006 Site Tools & Equip B	Elec Prod-Nuclear-MN-Monticello	6	-	6
10741615	Fleet New Unit Purchase El Ops	General Plant-ND	441,430	250,523	691,953
10741648	Fleet New Unit Purchase El Ops	General Plant-SD	280,475	486,344	766,819
10741664	Fleet New Unit Purchase Common	General Plant-ND	-	19,811	19,811
10769149	PI-1R-11/12&2R-11/12 Rad Mon	Elec Prod-Nuclear-MN-Prairie Island	(5)	-	(5)
10780769	NSP 5-Year Line Blanket Author	Elec Tran-Line-MN	614	-	614
10781699	WLM2C Upper Air Htr Mod Repla	Elec Prod-Steam-MN-Wilmarth	64,505	-	64,505
10781715	WLM1C Boiler Feed Chute Repla	Elec Prod-Steam-MN-Wilmarth	50,074	-	50,074
10781743	WLM0C Walking Floor Replaceme	Elec Prod-Steam-MN-Wilmarth	207,177	-	207,177
10782355	SER-0-C-SMC-2011 Misc. Tools	General Plant-MN	90,835	4,010	94,845
10783147	NSP 5-Year Relay Blanket Auth	Elec Tran-Sub-MN	(0)	-	(0)
10784493	BDS0111 2011 Tool Blanket	General Plant-MN	10,757	-	10,757
10784959	HNI3C-U3 Runners Replace	Elec Prod-Hydro-MN-Hennepin ISD	11,390	-	11,390
10784960	HNI4C-U4 Runners Replace	Elec Prod-Hydro-MN-Hennepin ISD	1,626,976	-	1,626,976
10784962	HNI3C-U3 Generator Rewind	Elec Prod-Hydro-MN-Hennepin ISD	(52,739)	-	(52,739)

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10784963	HNI4C-U4 Generator Rewind	Elec Prod-Hydro-MN-Hennepin ISD	381,748	-	381,748
10784965	HNI0C-Plant Automation	Elec Prod-Hydro-MN-Hennepin ISD	2,355,866	-	2,355,866
10784969	HNI5C-U5 Runners Replace	Elec Prod-Hydro-MN-Hennepin ISD	-	1,399,616	1,399,616
10784971	HNI5C-U5 Generator Rotor	Elec Prod-Hydro-MN-Hennepin ISD	-	526,559	526,559
10785193	SD Relocation Blanket	Elec Tran-Line-SD	374	-	374
10785206	ND Relocation Blanket	Elec Tran-Line-ND	525,628	-	525,628
10785449	SER-0-C-MMR1201-Videoprobe	General Plant-MN	49,990	10	50,000
10785642	HBC0C HB CC Tool Blank 2011	General Plant-MN	20,082	-	20,082
10785658	HBC8C U8 Hot Gas Path 16K EOH	Elec Prod-Other-MN-High Bridge-MERP	613,130	-	613,130
10785661	HBC7C U7 Combustion Inspection	Elec Prod-Other-MN-High Bridge-MERP	303,443	-	303,443
10785670	SHC U3 Repl Ash Silo Mixers	Elec Prod-Steam-MN-Sherburne	36,171	-	36,171
10785682	SHCJC Recnstr Coal Yard Ditch L	Elec Prod-Steam-MN-Sherburne	1,202	-	1,202
10785725	SER-0-C-MMR1202-Tools & Equipment	General Plant-MN	32,514	2,669	35,183
10785734	SER-0-C-MMR-Replace ET MIZ-21A	General Plant-MN	24,591	-	24,591
10785737	SHCJ UJ 57 Belt Conv Gallery H	Elec Prod-Steam-MN-Sherburne	3,310	-	3,310
10785744	SER-0-C PMO0113 Wireless Test T	General Plant-MN	-	31,000	31,000
10785746	SHCJC 4C Belt Conv Gallery Hea	Elec Prod-Steam-MN-Sherburne	611,063	9,698	620,761
10786005	SHCJC Ut J 2009 Tools & Equip Repl	General Plant-MN	0	-	0
10786221	SHC3C 11 Mill Ovrhl-Rpl Pulvzr	Elec Prod-Steam-MN-Sherburne	13	-	13
10786278	SHCJC UJ 2011 Tools and Equip	General Plant-MN	100,405	5	100,410
10786683	SHC3C U3 Turbine Increase Capa	Elec Prod-Steam-MN-Sherburne	566,307	-	566,307
10786941	IVH6C-U6 Turbine Rotor Disc Re	Elec Prod-Other-MN-Inver Hills	1,346,891	-	1,346,891
10786966	ANS0C-2011 Misc Tools & Equipm	General Plant-SD	17,085	-	17,085
10786967	BLL0C-2011 Misc Tools and Equi	General Plant-MN	4,452	-	4,452
10790334	Logistics - NSPM - Tools	General Plant-MN	173,581	111,002	284,584
10794783	CSC0107-Can Crusher	General Plant-MN	24,996	4	25,000
10796310	North Dakota Inspect, replace	Elec Dist-Mass-ND	206,584	219,453	426,037
10796786	500 kV Line	Elec Tran-Line-MN	(1,587)	-	(1,587)
10796852	Intelliteam SG Rollout	Elec Dist-Mass-MN	962,919	78,241	1,041,160
10796998	Minnesota inspect/replace pole	Elec Dist-Mass-MN	4,936,946	2,546,085	7,483,031
10797036	South Dakota - Inspect/Replace	Elec Dist-Mass-SD	141,523	657,815	799,339
10798851	PI- Relicense ISFSI	Elec Prod-Nuclear-MN-Prairie Island	-	4,124,362	4,124,362
10799010	ASK1C-Reheater Tube Section Re	Elec Prod-Steam-MN-Allen S King	-	19,691,925	19,691,925
10799065	PI1 Reload 27 (C28)	Elec Prod-Nuclear-MN-Prairie Island	76,286,937	-	76,286,937
10799276	MNGP Remote Camera Monitoring	Elec Prod-Nuclear-MN-Monticello	-	4,679,255	4,679,255
10799344	MNGP DAS & PPCS Rplc	Elec Prod-Nuclear-MN-Monticello	-	2,000,813	2,000,813
10799659	MNGP Facilities Infrastructure	Elec Prod-Nuclear-MN-Monticello	(265,449)	-	(265,449)

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10799675	MNGP RHRSW Pump Assembly	Elec Prod-Nuclear-MN-Monticello	502,226	-	502,226
10799679	MNGP Security Equipment Replac	Elec Prod-Nuclear-MN-Monticello	49,912	-	49,912
10799951	2011 WAN/LAN Refresh MN	General Plant-MN	13,280	-	13,280
10799955	2011 Radio/Micro Refresh MN	General Plant-MN	(800)	-	(800)
10799957	2011 PC Refresh - MN	General Plant-MN	1,877	-	1,877
10799962	2011 Server Refresh - MN	General Plant-MN	(106)	-	(106)
10799978	2011 EMS Hdwr/Wrkstn Repl - MN	General Plant-MN	695	-	695
10801476	PI-U1 Turb Oil Reservoir Filtr	Elec Prod-Nuclear-MN-Prairie Island	1,815,839	1,713,540	3,529,378
10801631	PI Chemistry Instr Upgrd (WinCDMS)	Elec Prod-Nuclear-MN-Prairie Island	64,824	-	64,824
10810516	OMS Expansion Project-OEP	Computer Software-MN	2,227,843	-	2,227,843
10812281	Strategic Technology - NSPM	Computer Software-MN	1,033,133	1,201,828	2,234,961
10815861	MN Cellnet Electric Meters	Elec Dist-Mass-MN	1,733,130	-	1,733,130
10815870	MN Elec Cellnet Comm Modules	General Plant-MN	586,412	-	586,412
10815972	Bill Print ReDesign	Computer Software-MN	589,052	-	589,052
10841412	WLM0C Station Battery Replacement	Elec Prod-Steam-MN-Wilmarth	(1,001)	-	(1,001)
10889130	CapX Brookings Proj Dvlp, Non S	Elec Tran-Line-MN	-	19,360,258	19,360,258
10889132	CapX LaCrosse Proj Dvlp, Non S	Elec Tran-Line-MN	-	1,174,706	1,174,706
10889149	CapX Agreements Templates	Elec Tran-Line-MN	1	-	1
10889155	CapX 345 CON	Elec Tran-Line-MN	1	-	1
10889163	CapX Fargo Development, Non Sh	Elec Tran-Line-MN	1,225,756	-	1,225,756
10910062	SHC1C U1 Emissions Reduction Proj	Elec Prod-Steam-MN-Sherburne	320,446	-	320,446
10910064	SHC2C U2 Emissions Reduction Proj	Elec Prod-Steam-MN-Sherburne	270,689	-	270,689
10911859	SD Transmission Line Blanket	Elec Tran-Line-SD	3,907	0	3,908
10912324	Monti Reload 26 (C27)	Elec Prod-Nuclear-MN-Monticello	-	79,898,669	79,898,669
10912329	PI Unit 2 Reload 27 (C28)	Elec Prod-Nuclear-MN-Prairie Island	-	52,586,833	52,586,833
10930204	REW0C-East Cell 3A Closure Lan	Elec Prod-Steam-MN-Red Wing	-	306,559	306,559
10930259	REW0C-Tools 2012	General Plant-MN	29,303	-	29,303
10930263	SHCJC UJ 2012 Tools and Equip	General Plant-MN	189,278	10,829	200,106
10930392	HBC0C HB CC Tool Blank 2012	General Plant-MN	20,177	-	20,177
10930404	HBC0C HB CC Tool Blank 2013	General Plant-MN	-	50,000	50,000
10931219	BDS0C 2012 Tool Blanket	General Plant-MN	94,933	-	94,933
10933069	SER-0-C-SMC-2012 Misc. Tools	General Plant-MN	149,669	251	149,920
10933101	WLM0C 2011 Tools & Equipment B	General Plant-MN	20,587	0	20,587
10934177	SHCCC Yard Dm Pipng 1100 Lin	Elec Prod-Steam-MN-Sherburne	(266)	-	(266)
10934289	SHCCC Pond 2 Capping PH III	Elec Prod-Steam-MN-Sherburne	722	-	722
10934296	SHC2C Repl 27 HP Feedwater Hea	Elec Prod-Steam-MN-Sherburne	-	2,386,881	2,386,881
10935154	HNI0C 2012 Misc Tools for SAF	General Plant-MN	10,194	-	10,194

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10936352	ANS0C 2012 Anson Misc Tools Blanket	General Plant-SD	14,960	40	15,000
10936407	BLL0C 2012 MN Peaking Tool Blanket	General Plant-MN	14,691	309	15,000
10936726	Install Wind Power Storage Ba	Elec Prod-Other-MN-Wind Storage	(67,147)	-	(67,147)
10936995	ASK1C-Boiler Water Makeup Demi	Elec Prod-Steam-MN-Allen S King	-	2,424,788	2,424,788
10937196	CS Cap Tools & Equipment - Com	General Plant-MN	18,801	1	18,803
10937220	CS Mechanical - common	Office, Service & Other Bldgs-MN	2,490	291	2,781
10937225	ASK0C-2012 Tool Blanket	General Plant-MN	111,052	8,948	120,000
10937227	CS Electrical - common	Office, Service & Other Bldgs-MN	1,440	169	1,610
10937228	ASK1C-2012 Boiler FW Insul & A	Elec Prod-Steam-MN-Allen S King	159,390	-	159,390
10937410	SER-0-C-CHM 11 Gas Chromatograph	General Plant-MN	73,055	-	73,055
10937440	SER-0-C-MMR 11 Video Crawler	General Plant-MN	(483)	-	(483)
10937447	SER-0-C-CHM-0112 Spectrophotmeter	General Plant-MN	152,930	70	153,000
10937831	SER-0-C-CHM-0212 Misc. Tools	General Plant-MN	19,589	411	20,000
10940986	CS Office Furniture & Equip Co	Office, Service & Other Bldgs-MN	88,601	5	88,606
10941938	Chisago Co - Breakers	Elec Tran-Sub-MN	15,701	-	15,701
10942409	Coon Creek - Breakers	Elec Tran-Sub-MN	(58)	-	(58)
10942462	Kegan Lake - Lebanon Hills	Elec Tran-Line-MN	(5,019)	-	(5,019)
10942466	King - Breakers	Elec Tran-Sub-MN	(129,599)	-	(129,599)
10942497	Monticello - Breaker	Elec Tran-Sub-MN	(1,546)	-	(1,546)
10942526	Split Rock - Breakers	Elec Tran-Sub-SD	-	1,781,819	1,781,819
10942533	TIP-L NSPM Wood Structures	Elec Tran-Line-MN	460	-	460
10942538	TIP-S NSPM Relays	Elec Tran-Sub-MN	121,436	-	121,436
10947269	Rein Lindstrom Sub 2 28 MVA	Elec Dist-Sub-MN	5	-	5
10947274	1/1/2008Inst Feeder EBL to HHH	Elec Dist-Mass-MN	48,975	-	48,975
10947391	Relocate for LRT in St. Paul	Elec Dist-Mass-MN	1,668,292	-	1,668,292
10948327	Reliability Monitoring Sys REM	Elec Dist-Mass-MN	52,141	1,932,326	1,984,466
10948331	Reliability Monitoring System	Elec Dist-Mass-ND	14,624	13,073	27,697
10948334	Reliability Monitoring System	Elec Dist-Mass-SD	15,570	13,416	28,986
10948462	Commodity Management System	Computer Software-MN	(417,253)	-	(417,253)
10948897	2012 LAN/WAN Refresh	General Plant-MN	353,659	-	353,659
10948934	2012 PC Planned Refresh MN	General Plant-MN	1,564,713	32,943	1,597,656
10948958	2012 Server Refresh	General Plant-MN	370,243	45,990	416,234
10948978	2012 Voice Refresh	General Plant-MN	352,000	-	352,000
10949004	2012 Radio/Microwave Refresh	General Plant-MN	99,894	-	99,894
10950500	Misc Building Projects	Office, Service & Other Bldgs-MN	807,325	1,040,366	1,847,690
10953801	Install Auto Source Transfer for MN	Elec Dist-Mass-MN	97,375	90,416	187,791
10953864	Land for Oakland Substation	Elec Dist-Sub-MN	369,979	-	369,979

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Project	Description	Major Location	2012	2013	Grand Total
10954865	Inst 2 Fdrs from BCR#1	Elec Dist-Mass-MN	-	242,490	242,490
10954877	reinf 13.8kv BCR #1 50MVA	Elec Dist-Sub-MN	-	54,392	54,392
10954893	Environmental Work NSPM EL	Elec Dist-Mass-MN	105,187	230,474	335,661
10956880	MNGP Contam Monitors (ARGOS)	Elec Prod-Nuclear-MN-Monticello	(144)	(0)	(144)
10957083	MNGP Cooling Tower Cell Re	Elec Prod-Nuclear-MN-Monticello	(10,131)	-	(10,131)
10958468	PI 121 CT Deck, Header, Valves	Elec Prod-Nuclear-MN-Prairie Island	-	2,203,661	2,203,661
10965933	Comm Wind N - G586 at Yankee S	Elec Tran-Sub-MN	1,832	-	1,832
10987111	NSPM E Corp Sec Build	Office, Service & Other Bldgs-MN	34,014	-	34,014
10987149	NSPM C Corp Sec Furn	General Plant-MN	202,605	321,426	524,031
10987155	NSPM E Corp Sec Furn	General Plant-MN	490,302	361,466	851,768
10999134	West New Ulm Sub - Land	Elec Tran-Sub-MN	228,597	-	228,597
10999142	Install 69kV Line 0719 Searle	Elec Tran-Line-MN	(2,197)	-	(2,197)
11039033	PI-Calculatoin Recovery & Impr	Elec Prod-Nuclear-MN-Prairie Island	3,395	-	3,395
11043842	MNGP Fire PRA Model Tool	Elec Prod-Nuclear-MN-Monticello	-	12,097,384	12,097,384
11045400	SHC3C U3 Uprate Project	Elec Prod-Steam-MN-Sherburne	121,252	-	121,252
11046737	Reinf FAPTR1 to 28MVA	Elec Dist-Sub-MN	-	20,388	20,388
11055854	MN Substation Construction	Elec Tran-Sub-MN	26	-	26
11057269	NSP TAM Non-Allocated Capital	Elec Tran-Line-MN	(9,164,839)	-	(9,164,839)
11064545	Control Center Chairs	General Plant-MN	1,389	-	1,389
11065581	HPFF upgrade - Lines	Elec Tran-Line-MN	22,278	-	22,278
11065584	HPFF upgrade - Subs	Elec Tran-Sub-MN	1,689,331	-	1,689,331
11071339	SER-0-C SMC 2013 Misc tools	General Plant-MN	-	149,071	149,071
11074745	SHC1C Replace 17 Feedwater Hea	Elec Prod-Steam-MN-Sherburne	2,475,134	-	2,475,134
11074770	SHCJC UJ Yard Scraper Repl 201	Elec Prod-Steam-MN-Sherburne	(834)	-	(834)
11075097	SHCJC UJ Yard Scraper Repl 201	Elec Prod-Steam-MN-Sherburne	(831)	-	(831)
11075119	SHCCC Repl U1 2 Stack Elevator	Elec Prod-Steam-MN-Sherburne	809,859	-	809,859
11078818	IVHC0 2012 Small Tools Blanket	General Plant-MN	15,161	-	15,161
11078822	IVHC0 2013 Small Tools Blanket	General Plant-MN	-	15,000	15,000
11078874	SHCCC Repl U1 and 2 Coal Sampl	Elec Prod-Steam-MN-Sherburne	-	2,054,273	2,054,273
11078875	ANSC0 2013 Angus Anson Tool Bl	General Plant-SD	-	13,000	13,000
11078894	BLLC0 2013 Misc Tools Blanket	General Plant-MN	-	14,958	14,958
11079931	REW0113 Capital Tools 2013	General Plant-MN	-	30,000	30,000
11079942	REW0313-Bottom Ash Conveyor U2	Elec Prod-Steam-MN-Red Wing	-	94,664	94,664
11080117	WLM0C 2012 Tools & Equipment B	General Plant-MN	59,706	-	59,706
11080119	WLM0C 2013 Tools & Equipment B	General Plant-MN	-	60,000	60,000
11080687	BDS0C 2013 Tool Blanket	General Plant-MN	-	95,000	95,000
11081139	NSP Spare 345-161kV 336MVA Trans	Elec Tran-Sub-MN	2,246,987	-	2,246,987

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11081144	NSP Spare 161-115 Transformer	Elec Tran-Sub-MN	109,046	-	109,046
11081149	Kohlman Lake Replace 345 kV Relayin	Elec Tran-Sub-MN	1,171,585	-	1,171,585
11081155	Sheyenne- Install Fault Recorder	Elec Tran-Sub-MN	981	-	981
11081185	Chisago Co - Fault Recorder	Elec Tran-Sub-MN	434	-	434
11082583	HNIC0 2013 HNI Small Tools Blanket	General Plant-MN	-	14,970	14,970
11082588	HNIC0 Roof Replacement	Elec Prod-Hydro-MN-Hennepin ISD	-	400,642	400,642
11082769	NSPM T-Line EOL Rplmnts PH 3	Elec Tran-Line-MN	1,224,215	-	1,224,215
11082815	NSPM T-Line EOL Rplmnts PH 2	Elec Tran-Line-MN	662,414	-	662,414
11083225	Paynesville 115/69 Transformer	Elec Tran-Sub-MN	337	-	337
11083232	Osakis (West Union) Ssauk Centre Li	Elec Tran-Line-MN	4,011,049	-	4,011,049
11083237	Lawerance 2nd 115/69 tranformer Lin	Elec Tran-Line-SD	5,021	-	5,021
11083239	Lawerance 2nd 115/69 transformer Su	Elec Tran-Sub-SD	323	-	323
11083242	Lake City 2nd Source Line	Elec Tran-Line-MN	521,154	-	521,154
11083243	SHC1C Repl Bottom Ash Sluice G	Elec Prod-Steam-MN-Sherburne	686,374	-	686,374
11083250	Fenton 69 kV Interconnection Line	Elec Tran-Line-MN	20,012	-	20,012
11083252	Fenton 69 kV Interconnection Sub	Elec Tran-Sub-MN	83,811	-	83,811
11083259	Douglas County 0867, Line	Elec Tran-Line-MN	2,854	-	2,854
11083265	Douglas County 2nd 115/69 Xmfr Sub	Elec Tran-Sub-MN	596	-	596
11083273	ASK0C-2013 Tool Blanket	General Plant-MN	-	118,903	118,903
11083280	SHCCC Pond 3S Vertical Extensi	Elec Prod-Steam-MN-Sherburne	-	799,209	799,209
11083296	RIV9C Combustion Inspection Pa	Elec Prod-Other-MN-Riverside-MERP	2,946,697	-	2,946,697
11083317	RIV0C-2011 Tool Blanket	General Plant-MN	9,826	-	9,826
11083330	RIV10C-U10 Combustion Inspect No 1	Elec Prod-Other-MN-Riverside-MERP	-	300,539	300,539
11083345	RIV0C-2012 Tool Blanket	General Plant-MN	49,332	-	49,332
11083373	RIV0C-2013 Tool Blanket	General Plant-MN	-	60,000	60,000
11083615	West Waconia-Scott 115kV Sub	Elec Tran-Sub-MN	9,243	-	9,243
11083637	Transmission Oil Containment sub	Elec Tran-Sub-MN	185	-	185
11083649	North Mankato 115kV plan Line	Elec Tran-Line-MN	911	-	911
11083668	Lake Emily Cap Bank Sub	Elec Tran-Sub-MN	(9,000)	-	(9,000)
11084048	SHCJC UJ Tools and Equipment	General Plant-MN	-	164,335	164,335
11084515	SER0C-MMR1203-Digital Imaging Syst	General Plant-MN	11,998	2	12,000
11084517	SER0C-MMR1204-ET Analysis equipmen	General Plant-MN	9,998	2	10,000
11084519	SER0C-MMR1301-Tools and Equip	General Plant-MN	-	24,996	24,996
11084525	SER0C-CHM0113 Gas Chromatograph	General Plant-MN	-	50,977	50,977
11084540	SER0C-PMO0112 Wireless Testing Trns	General Plant-MN	36,926	2	36,928
11086454	GRE Crooked Lk-Enterprize Park 115k	Elec Tran-Sub-MN	-	2,747,407	2,747,407
11086497	WNDC0 2012 Wind Tool Blanket	General Plant-MN	19,588	412	20,000

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Project	Description	Major Location	2012	2013	Grand Total
11086500	WNDC0 2013 Wind Tool Blanket	General Plant-MN	-	10,000	10,000
11086757	Pleasant Valley - Byron 161kV Line	Elec Tran-Line-MN	3,340,725	-	3,340,725
11086835	BDS5C U5 Generator Stator Rewi	Elec Prod-Other-MN-Black Dog	3,476,610	-	3,476,610
11087316	Purch Radios MN outside projec	General Plant-MN	5,173,935	-	5,173,935
11087337	2011 Planned Telecom Refresh	General Plant-MN	7,379	-	7,379
11087426	2012 Planned Telecom Refresh	General Plant-MN	52,529	7,469	59,998
11087435	2012 Planned Telecom Refresh	General Plant-MN	-	55,006	55,006
11087470	2011 Unplanned LAN WAN Refresh	General Plant-MN	44,947	46	44,993
11087479	2012 Unplanned LAN WAN Refresh	General Plant-MN	88,064	200	88,263
11087493	2013 Unplanned LAN WAN Refresh	General Plant-MN	-	76,005	76,005
11087595	WLM1C Lower Air Heater Repl	Elec Prod-Steam-MN-Wilmarth	80,124	-	80,124
11087596	WLM2C Lower Air Heater Repl	Elec Prod-Steam-MN-Wilmarth	68,900	-	68,900
11087597	WLM0C Landfill Cell 7B/8A Clos	Elec Prod-Steam-MN-Wilmarth	-	356,073	356,073
11088349	SER0C-CHM0213 DGA Gas Chromatograp	General Plant-MN	-	50,997	50,997
11088351	SER-0-C-CHM0313 Misc. Tools	General Plant-MN	-	19,259	19,259
11088473	2012 Unplanned Radio Refresh	General Plant-MN	67,208	101	67,309
11088483	2013 Unplanned Radio Refresh	General Plant-MN	-	50,000	50,000
11088521	2012 Unplanned Telecom Refresh	General Plant-MN	35,660	4,339	39,999
11088534	2013 Unplanned Telecom Refresh	General Plant-MN	-	38,501	38,501
11088578	2012 Unplanned Voice Refresh	General Plant-MN	38,654	1,346	40,000
11088601	2013 Unplanned Voice Refresh	General Plant-MN	-	38,501	38,501
11088691	2013 Planned LAN WAN Refresh	General Plant-MN	-	542,568	542,568
11088705	2013 Planned Radio MW Refresh	General Plant-MN	-	97,502	97,502
11088715	2013 Planned Voice Refresh	General Plant-MN	-	372,527	372,527
11088743	2013 Server Refresh	General Plant-MN	-	364,035	364,035
11088752	2013 EMS Workstation Hardware	Communication Site-MN	-	65,606	65,606
11088759	2013 Planned PC Refresh	General Plant-MN	-	1,597,494	1,597,494
11090036	REW0C-Scalping Conveyor Replac	Elec Prod-Steam-MN-Red Wing	315,330	-	315,330
11095063	Relocate 4.2 miles of AFT315 Feeder	Elec Dist-Mass-MN	1,590	-	1,590
11095139	SPCC NSPM Oil Spill Prevention	Elec Dist-Sub-MN	611,698	689,794	1,301,493
11096972	TPIP - North Dakota	Elec Dist-Mass-ND	34,229	1,575	35,805
11096984	MN Infrastructure Invest -OH Rebuild	Elec Dist-Mass-MN	-	2,669,225	2,669,225
11099409	Participate 115/13.8kV CHS Upgrade	Elec Dist-Sub-MN	505,709	872,922	1,378,630
11099447	RM- Relocate Feeders Rice St	Elec Dist-Mass-MN	(519,000)	-	(519,000)
11099780	MNGP 2013 Dry Fuel Storge Load	Elec Prod-Nuclear-MN-Monticello	-	36,930,636	36,930,636
11099788	MNGP 2013 LPRMs	Elec Prod-Nuclear-MN-Monticello	-	846,192	846,192
11100245	PI-Rewind 122 CT pmp Motor	Elec Prod-Nuclear-MN-Prairie Island	345,986	18,000	363,986

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Project	Description	Major Location	2012	2013	Grand Total
11100312	MNGP Site Blanket	Elec Prod-Nuclear-MN-Monticello	160,596	-	160,596
11100811	Reliability Monitoring System Minn	Elec Dist-Mass-MN	101,587	17,462	119,049
11100848	Reliability Monitoring System Mine	Elec Dist-Mass-MN	93,233	1,450	94,683
11100858	Reliability Monitoring System Edina	Elec Dist-Mass-MN	25,471	18	25,489
11100863	Reliability Monitoring System Fari	Elec Dist-Mass-MN	43,853	24	43,877
11100869	Reliability Monitoring System Newpo	Elec Dist-Mass-MN	87,940	1,166	89,106
11100898	Reliability Monitoring System WBear	Elec Dist-Mass-MN	207,575	4,947	212,522
11100904	Reliability Monitoring System NW	Elec Dist-Mass-MN	43,846	2,769	46,615
11101206	MNGP Plant Process Computer Rpic	Elec Prod-Nuclear-MN-Monticello	1,427,162	-	1,427,162
11101409	PI-U2 Przr PORVs Air Accumulat	Elec Prod-Nuclear-MN-Prairie Island	-	1,574,533	1,574,533
11101498	PI-9 TN-40 Casks (30-38)	Elec Prod-Nuclear-MN-Prairie Island	-	35,620,252	35,620,252
11102217	2011 Unplanned Server Refresh	General Plant-MN	838	2	840
11102263	2012 Unplanned Server Refresh	General Plant-MN	169,746	27,263	197,009
11102283	2013 Unplanned Server Refresh	General Plant-MN	-	412,942	412,942
11102446	2011 Unplanned PC Refresh	General Plant-MN	27,986	-	27,986
11102456	2012 Unplanned PC Refresh	General Plant-MN	387,503	23,599	411,102
11102493	2013 Unplanned PC Refresh	General Plant-MN	-	467,772	467,772
11102991	Install new Louise Sub	Elec Dist-Sub-SD	10,278	-	10,278
11103009	PI-Security Battery Replacemen	Elec Prod-Nuclear-MN-Prairie Island	1,568,169	-	1,568,169
11103036	PI Online Xfmr Mon 1GT,2GT,1M,	Elec Prod-Nuclear-MN-Prairie Island	605,598	-	605,598
11103043	Install 35 kV Sectionalizing Switch	Elec Dist-Mass-SD	87,637	339	87,976
11103046	Louise Sub feeders & exits	Elec Dist-Mass-SD	46,171	-	46,171
11103171	PI-2010 I/T Capital Blanket	General Plant-MN	2,220	-	2,220
11130541	Transportation Blanket, Trans MN	General Plant-MN	19,555	4,838	24,393
11134334	Maple Grove Imp. for 345kV Tran,sub	Office, Service & Other Bldgs-MN	1,523	-	1,523
11137360	Corp Data Warehouse Ph1	Computer Software-MN	501,402	-	501,402
11139476	115-14kV, 50MVA NSPM B-Reserve PURC	Elec Dist-Sub-MN	5,556	-	5,556
11154524	Nobles Wind	Elec Prod-Other-MN-Nobles Wind	125,469	-	125,469
11155526	Nobles Wind Farm Land Land Rts	Elec Prod-Other-MN-Nobles Wind	6,160	-	6,160
11155545	Merricourt Wind Farm New Substation	Elec Tran-Sub-ND	(51)	-	(51)
11160582	Install West Waconia Transformer #2	Elec Dist-Sub-MN	390	-	390
11160652	I3 Reconfigure NOR024 feeder	Elec Dist-Mass-ND	3	-	3
11164041	MDT s for Mobile Maint & Inspe	General Plant-MN	61,213	-	61,213
11177566	Hiawatha Project Transmission, Line	Elec Tran-Line-MN	-	3,184,203	3,184,203
11180728	GRE - St Lawrence Interconnect,Line	Elec Tran-Line-MN	-	644,340	644,340
11184334	G349 Brookings Wind Int. Sub	Elec Tran-Sub-SD	(725)	-	(725)
11189778	ND T-Line EOL Rplmts Ph 1, Line	Elec Tran-Line-ND	830,506	-	830,506

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Project	Description	Major Location	2012	2013	Grand Total
11200685	REW1C-Membrane Walls Replaceme	Elec Prod-Steam-MN-Red Wing	-	1,101,984	1,101,984
11200892	ASK1C-Ovation Controls Simulat	Elec Prod-Steam-MN-Allen S King	-	1,572,294	1,572,294
11201456	WLM0C Fuel & Ash PLC Replaceme	Elec Prod-Steam-MN-Wilmarth	528,702	-	528,702
11201746	Logistics - Fencing - NSPM	General Plant-MN	27,673	120,432	148,105
11201748	Logistics - Security Equipment-NSPM	General Plant-MN	5,000	53,555	58,555
11205897	MNGP Security Improvements 200	Elec Prod-Nuclear-MN-Monticello	(0)	-	(0)
11208552	FPIP Feeders - South Dakota	Elec Dist-Mass-SD	(285)	37,891	37,607
11209876	NSM0837-Replace 4 Structures,Line	Elec Tran-Line-MN	1,796,657	-	1,796,657
11210705	BDS5C U5 Row 1 Vanes	Elec Prod-Other-MN-Black Dog	2,514,991	-	2,514,991
11210833	Wind Forecasting-Mesonet Forec	Computer Software-MN	341,003	-	341,003
11214332	MNVC0 MN Falls Dam Remediation	Elec Prod-Steam-MN-Minn Valley	-	2,678	2,678
11215761	NBLC0 2012 Misc Tools Equip BI	General Plant-MN	39,750	250	40,000
11215828	NBLC0 2013 Misc Tools Equip	General Plant-MN	-	20,000	20,000
11215938	RIVOC-North Warehouse Demoliti	Elec Prod-Other-MN-Riverside-MERP	-	45,169	45,169
11217238	SHC3C U3 Backpass Sootblwng Sy	Elec Prod-Steam-MN-Sherburne	2,607,739	-	2,607,739
11217240	SHCCC New Stacker Rail & Found	Elec Prod-Steam-MN-Sherburne	3,623	-	3,623
11217241	SHCJC Stacker Elec & Contrl Sy	Elec Prod-Steam-MN-Sherburne	-	1,757,047	1,757,047
11217809	BS-Fcst-OTI-SW-CM-M	Computer Software-MN	-	1,959,125	1,959,125
11217851	ASK1C-HAZOP TH3 Dustless Trans	Elec Prod-Steam-MN-Allen S King	562,481	-	562,481
11217852	ASK1C-Screenhouse TrashRake Re	Elec Prod-Steam-MN-Allen S King	-	480,166	480,166
11217859	ASK1C-Feedwater Heater 16B Rep	Elec Prod-Steam-MN-Allen S King	-	1,335,046	1,335,046
11217860	ASK1C-AFC-1A Flite Conveyor Re	Elec Prod-Steam-MN-Allen S King	-	400,845	400,845
11217861	ASK1C-AFC-2B Flite Conveyor Re	Elec Prod-Steam-MN-Allen S King	-	402,371	402,371
11218004	BS-Fcst-MI-SW-CM-M	Computer Software-MN	-	1,277,323	1,277,323
11218029	BS-Fcst-BD-SW-CM-M	Computer Software-MN	(148,730)	87,814	(60,916)
11218059	BS-Fcst-CSR-SW-CM-M	Computer Software-MN	66,309	236,733	303,042
11218128	BS-Fcst-HWR-SW-CM-M	Computer Software-MN	158,301	169,748	328,049
11218800	Louise New Substation, Sub	Elec Tran-Sub-SD	399	-	399
11218803	Colvill 115/69kV Xmfr, Line	Elec Tran-Line-MN	1,246	-	1,246
11218805	Colvill 115/69kV Xmfr, Sub	Elec Tran-Sub-MN	(12,502)	-	(12,502)
11218822	GRE Nininger Interconnect, Line	Elec Tran-Line-MN	182	-	182
11218826	GRE Northport Interconnect,Line	Elec Tran-Line-MN	442,586	-	442,586
11218839	Grove Lake - Lowry, Line	Elec Tran-Line-MN	4,030,522	-	4,030,522
11218844	Pike Lake Interconnection, Line	Elec Tran-Line-MN	45	-	45
11218852	St Cloud Loop, Line	Elec Tran-Line-MN	-	414,173	414,173
11218854	St Cloud Loop - Sub	Elec Tran-Sub-MN	-	3,644,976	3,644,976
11218865	Louise New Substation, Line	Elec Tran-Line-SD	364	-	364

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11218892	Westgate TR1, Sub	Elec Tran-Sub-MN	322	-	322
11218904	Pike Lake Interconnection, Sub	Elec Tran-Sub-MN	28	-	28
11219375	Hiawatha 115kV, Land	Elec Tran-Sub-MN	-	3,995,000	3,995,000
11219377	Midtown 115 kV, Line	Elec Tran-Line-MN	-	17,041,324	17,041,324
11219619	NSP Line Capacity, Line	Elec Tran-Line-MN	794,358	1,448,137	2,242,495
11219660	NSP-APT 550 Replmts, Sub	Elec Tran-Sub-MN	109	-	109
11219661	NSPM-Ledex Replacements, Sub	General Plant-MN	530,247	-	530,247
11219664	NSPM Trans Switch Replmnt, Line	Elec Tran-Line-MN	208,493	-	208,493
11219667	NSPM Unserviceable Bkr R,Sub	Elec Tran-Sub-MN	194	-	194
11219669	Obsolete Breaker Replmnt, Sub	Elec Tran-Sub-MN	(106)	-	(106)
11219844	CAPX 2020 MN, ROW	Elec Tran-Line-MN	1,271,241	(123,946)	1,147,295
11220638	CAPX2020 La Crosse Underlying,Line	Elec Tran-Line-MN	4,807	448,231	453,038
11220643	CAPX2020 N/S Hampton MN, Land	Elec Tran-Sub-MN	250,506	-	250,506
11224397	Passport- ERO System Protectio	Computer Software-MN	1,371	-	1,371
11225112	Building Renovation/Remodel	Office, Service & Other Bldgs-MN	4,938,912	6,142,567	11,081,478
11225220	Roads and Gates	Office, Service & Other Bldgs-MN	158,314	166,545	324,859
11225235	Electrical	Office, Service & Other Bldgs-MN	35,136	37,536	72,672
11225241	Structural	Office, Service & Other Bldgs-MN	92,221	10,026	102,247
11225245	Mechanical	Office, Service & Other Bldgs-MN	1,596,818	1,370,568	2,967,387
11225246	Roof Replacement	Office, Service & Other Bldgs-MN	485,182	642,564	1,127,745
11225252	Tools & Equipment	Office, Service & Other Bldgs-MN	16,204	1	16,204
11225275	Office Furniture & equipment	Office, Service & Other Bldgs-MN	420,983	173,003	593,986
11225306	Unbudgeted Emergencies	Office, Service & Other Bldgs-MN	261,220	473,179	734,399
11225446	Fire Protection	Office, Service & Other Bldgs-MN	34,198	3,954	38,152
11226930	Logistics - NSPM - Tools - ND	General Plant-ND	15,607	10,934	26,542
11227014	BS-Fcst-OTI-NW-CM-M	General Plant-MN	224,298	1,605,200	1,829,498
11227064	BS-Fcst-MI-COMM-EL-M	Office, Service & Other Bldgs-MN	60,530	3,252,924	3,313,454
11227116	BS-Fcst-HWR-NW-CM-M	General Plant-MN	206,095	954,007	1,160,102
11227949	Barnes Sub- Retire 24-4kVSubstation	Elec Dist-Sub-ND	(547)	-	(547)
11227970	SHCCC 2012 Tools & Equipment	General Plant-MN	512,154	12,998	525,152
11227972	SHCCC 2013 Tools & Equipment	General Plant-MN	-	168,752	168,752
11228127	SER-0-CHM-0413- Trace Lvl Hg Anlyzr	General Plant-MN	-	34,999	34,999
11228176	NSM0519 Buffalo Ridge UG Rpl, Line	Elec Tran-Line-MN	3,243,850	-	3,243,850
11228295	Lowery Ave Bridge Reconstruction	Elec Dist-Mass-MN	625,220	-	625,220
11228305	Rd Widening Quentin Ave/123rd/Hwy	Elec Dist-Mass-MN	328,101	-	328,101
11229437	Install New Feeders on EDP #3	Elec Dist-Mass-MN	34	-	34
11230243	PI-2011 I/T Capital Blanket	General Plant-MN	242,933	-	242,933

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11230258	PI-2011 Misc Tools & Equipment	General Plant-MN	439,004	-	439,004
11230279	PI-2011 Misc Office Furniture	General Plant-MN	21,043	-	21,043
11230292	PI-10CFR73 Continuous Detection	Elec Prod-Nuclear-MN-Prairie Island	614	-	614
11230304	PI-10CFR73 Security-No Single Act	Elec Prod-Nuclear-MN-Prairie Island	200,492	-	200,492
11230311	PI-10CFR73 Pathways	Elec Prod-Nuclear-MN-Prairie Island	36,681	-	36,681
11230318	PI-GL0801 Modeling Software	Computer Software-MN	8,451	-	8,451
11230379	PI-Receiving Warehouse	Elec Prod-Nuclear-MN-Prairie Island	6,917,833	-	6,917,833
11230579	PI-Roof Replacements	Elec Prod-Nuclear-MN-Prairie Island	462,580	-	462,580
11230621	PI-HDTP Speed Control Repl	Elec Prod-Nuclear-MN-Prairie Island	3,281,923	2,906,646	6,188,570
11230749	PI Spare Circ Water Pump Motor	Elec Prod-Nuclear-MN-Prairie Island	1,282,140	-	1,282,140
11230885	Replace Distribution Cabinets-NSPM	Elec Dist-Mass-MN	13,733	59,805	73,538
11230972	PI-123 CT Motors & Gear Boxes	Elec Prod-Nuclear-MN-Prairie Island	-	950,585	950,585
11230990	SHC3C U3 Baghouse Bag Repl	Elec Prod-Steam-MN-Sherburne	1,664,421	-	1,664,421
11231007	Inst new 13.8kV Breaker at Aldrich	Elec Dist-Sub-MN	20	-	20
11232908	Tran Line MN Tax Rebate, Line	Elec Tran-Line-MN	(3,000,000)	-	(3,000,000)
11232958	10CFR73 Security Detection & A	Elec Prod-Nuclear-MN-Monticello	81,001	-	81,001
11233042	MNGP RHRSW Pipe Rpl Div II	Elec Prod-Nuclear-MN-Monticello	(333,630)	-	(333,630)
11233049	MNGP #13 250V Battery Replacem	Elec Prod-Nuclear-MN-Monticello	-	460,643	460,643
11233067	MNGP #11 125V Battery Replacem	Elec Prod-Nuclear-MN-Monticello	-	242,067	242,067
11233143	MNGP Security Range Upgrades	Elec Prod-Nuclear-MN-Monticello	1,056,009	-	1,056,009
11233281	MNGP Noble Chem Mitgton & Mntr	Elec Prod-Nuclear-MN-Monticello	-	11,258,131	11,258,131
11236521	LEX-GLK Re-Conductor	Elec Tran-Line-MN	13,220	-	13,220
11236978	Logistics - Tools - SD	General Plant-SD	38,735	17,221	55,956
11247020	G287 enXco Nobles -Network, Sub	Elec Tran-Sub-MN	179	-	179
11251067	Kelso Substation	Elec Tran-Sub-MN	137	-	137
11252228	CAPX2020 Quarry Sub(Non-Shared)	Elec Tran-Sub-MN	103,389	-	103,389
11252532	CAPX2020 Monti Sub, (Non-Share	Elec Tran-Sub-MN	54,734	-	54,734
11256373	SHERCO Sub - Reactive, Sub	Elec Tran-Sub-MN	1,342	-	1,342
11256400	ELM Creek Sub-Reactive, Sub	Elec Tran-Sub-MN	615	-	615
11258660	Corporate Data Warehouse Ph3-T	Computer Software-MN	1,927,429	-	1,927,429
11260515	SWTC - Con & R Permit, Line	Elec Tran-Line-MN	890,779	-	890,779
11267546	eDiscovery Ph 2	Computer Software-MN	8,825	-	8,825
11271740	PI Cold Chem Lab Sample Coolin	Elec Prod-Nuclear-MN-Prairie Island	204,178	-	204,178
11272752	Eden Prairie Sub #3	Elec Tran-Sub-MN	46,709	-	46,709
11274627	Asset Sale - MN Substation	Elec Dist-Sub-MN	(237)	-	(237)
11275941	Convert AFT315-AFT321-B tie to 35kV	Elec Dist-Mass-MN	0	-	0
11286886	Install new feeder off TLK TR1	Elec Dist-Mass-MN	0	-	0

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11287962	Lafayette Bridge Relocation	Elec Dist-Mass-MN	26,981	-	26,981
11290561	Install new Indiana 13.8kV feeder	Elec Dist-Mass-MN	2	-	2
11294210	Install West Waconia Transformer #2	Elec Dist-Mass-MN	(3)	-	(3)
11296804	CRM Sales Force SW MN	Computer Software-MN	1,342,306	-	1,342,306
11301858	MNGP Plant Computer Blanket 20	Elec Prod-Nuclear-MN-Monticello	99,891	-	99,891
11302421	10CFR73 No Single Act New Sec	Elec Prod-Nuclear-MN-Monticello	393,000	-	393,000
11302806	Fleet new Unit 2011, EI Trans, MN	Transportation Equipment-MN	1,002,142	-	1,002,142
11302821	Fleet New Units 2012 EI Trans,	Transportation Equipment-MN	8,090,877	-	8,090,877
11302824	Fleet New Unit 2013 EI Trans, MN	Transportation Equipment-MN	-	7,350,000	7,350,000
11303181	Line 760 replace structures, Line	Elec Tran-Line-MN	(14,021)	-	(14,021)
11303974	Mallard Substation	Elec Tran-Sub-ND	-	75,988	75,988
11303978	Forbes 500 kV Relay Replacement,Sub	Elec Tran-Sub-MN	21,972	-	21,972
11304499	Cannon Falls - Breaker ELR, Sub	Elec Tran-Sub-MN	(169)	-	(169)
11304507	Southtown - Breaker ELR, Sub	Elec Tran-Sub-MN	2,456	-	2,456
11304511	Douglas County - Breaker ELR, Sub	Elec Tran-Sub-MN	263	-	263
11304516	South Breaker ELR, Sub	Elec Tran-Sub-ND	(112)	-	(112)
11307887	West Waconia Transformer #2, Sub	Elec Tran-Sub-MN	(215)	-	(215)
11314218	Relocate for LRT in St Paul-UG Net	Elec Dist-Mass-MN	3,531	-	3,531
11314865	ELP085 Dist Feeder Comm Equip	General Plant-MN	421	-	421
11315523	CAPX Fargo-Monti-Quarry Non Sh	Elec Tran-Line-MN	507,458	-	507,458
11315533	NSM 752 Glenwood - Lowry, Line	Elec Tran-Line-MN	386	-	386
11318446	Lake Emily XMSN Switches	Elec Dist-Sub-MN	8,635	-	8,635
11325531	NSPM Inspect/Replace Poles	Elec Dist-Mass-MN	136,351	84,994	221,345
11325534	ND Inspect/Replace Poles	Elec Dist-Mass-ND	1,228	3,951	5,179
11325535	SD Inspect/Replace Poles	Elec Dist-Mass-SD	-	11,797	11,797
11327764	Roseau Co-Series Cap Ctrl Sys Ph 2	Elec Tran-Sub-MN	315	-	315
11328950	VAR - Network System Project	General Plant-MN	1,001,446	-	1,001,446
11329406	NSPM 2010 S&E B, Line	Elec Tran-Line-MN	9,089	-	9,089
11329488	SD 2010 S&E B, Line	Elec Tran-Line-SD	(6,218)	-	(6,218)
11330051	NSPM 2011 S&E B, Line	Elec Tran-Line-MN	363,010	-	363,010
11330057	MSPM 2012 S&E B, Line	Elec Tran-Line-MN	1,266,557	-	1,266,557
11330067	NSPM 2013 S&E B, Line	Elec Tran-Line-MN	-	1,519,301	1,519,301
11332944	H102 - Line 0911 (Mallard), Line	Elec Tran-Line-ND	242,439	-	242,439
11333104	MNGP 2010 Tools & Equipment	Elec Prod-Nuclear-MN-Monticello	80,196	-	80,196
11335513	SD Pole Trussing, 2010, Line	Elec Tran-Line-SD	7,839	-	7,839
11337412	Reinforce WSF073 feeder	Elec Dist-Mass-SD	(316,274)	-	(316,274)
11338876	Parkers Lake Sub	Elec Tran-Sub-MN	12,949	-	12,949

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11338880	Split Rock Sub	Elec Tran-Sub-SD	409	-	409
11339041	MNGP Repl of Fetterolf Manifol	Elec Prod-Nuclear-MN-Monticello	-	775,432	775,432
11340153	Byron-Replace 345kV Relay for Smmpa	Elec Tran-Sub-MN	74	-	74
11342151	CAPX 0954Quarry-Alexandria 345	Elec Tran-Line-MN	2,985,470	-	2,985,470
11342162	CAPX 0955(MN)Alexandria-ND Bor	Elec Tran-Line-MN	3,269,609	1,703,104	4,972,713
11342169	CAPX 0955(ND)ND Border to Biso	Elec Tran-Line-ND	984,671	-	984,671
11342687	Retire Portal Pipeline substation i	Elec Dist-Sub-ND	20,896	-	20,896
11342944	CAPX Fargo- Bison Sub (ND), La	Elec Tran-Sub-ND	420,034	-	420,034
11342951	CAPX North Rochester N/S, Land	Elec Tran-Sub-MN	500,000	-	500,000
11344510	H103-Mallard Sub relay & Bus Int.,S	Elec Tran-Sub-ND	111,333	-	111,333
11344952	HBC0C Ammonia Safety Shower	Elec Prod-Other-MN-High Bridge-MERP	1,766	-	1,766
11344953	HBC9C St Turbine Bently Nev Up	Elec Prod-Other-MN-High Bridge-MERP	112,361	-	112,361
11344962	HBC0C GE System 1 Vibration	Elec Prod-Other-MN-High Bridge-MERP	234,794	-	234,794
11344973	HBC7C U7 Air Intake Hi Effic F	Elec Prod-Other-MN-High Bridge-MERP	-	94,835	94,835
11344977	HBC8C Air Intake hi Eff Filter	Elec Prod-Other-MN-High Bridge-MERP	-	94,835	94,835
11344979	HBC7C Generator Partial Disch	Elec Prod-Other-MN-High Bridge-MERP	-	77,502	77,502
11344983	HBC8C Generator Partial Disch	Elec Prod-Other-MN-High Bridge-MERP	-	76,725	76,725
11347913	GDMC0 Gearbox Replacements	Elec Prod-Other-MN-Grand Meadow	1,227,411	-	1,227,411
11347920	GDMC0 Condition Monitor Sys	Elec Prod-Other-MN-Grand Meadow	849	-	849
11347926	GDMC0 Central Greasing Sys	Elec Prod-Other-MN-Grand Meadow	22,984	-	22,984
11347935	0740 Cnvert Augusta-Chaska-SCT, Lin	Elec Tran-Line-MN	-	434,908	434,908
11347947	0871 Laminate Arms, Line	Elec Tran-Line-MN	217,375	-	217,375
11347949	5503 SPK-CHC Laminate Arms	Elec Tran-Line-SD	814	-	814
11347954	Buffalo Ridge Substation Eq, S	Elec Tran-Sub-MN	(0)	-	(0)
11347980	Hollydale 115kV Conversion, Su	Elec Tran-Sub-MN	-	1,175,640	1,175,640
11347982	Hollydale to Medina Purchase G, Li	Elec Tran-Line-MN	131	498,702	498,834
11348022	Meadowlake to Twin Lakes 115kV,ROW	Elec Tran-Line-MN	-	500,000	500,000
11348028	SHC2C Repl 22 Main Station Aux	Elec Prod-Steam-MN-Sherburne	-	1,311,815	1,311,815
11348030	Medina 115kV Conversion, Sub	Elec Tran-Sub-MN	-	50,071	50,071
11348035	SHC3C Repl Primary Air Heatr B	Elec Prod-Steam-MN-Sherburne	36	-	36
11348036	GDMC0 2012 Generator Replaceme	Elec Prod-Other-MN-Grand Meadow	133,703	-	133,703
11348045	MN Pole Trussing, 2012, Line	Elec Tran-Line-MN	7,561	-	7,561
11348050	MN Pole Trussing, 2013, Line	Elec Tran-Line-MN	-	75,568	75,568
11348061	2011 NSM Major Line Refurbishment,L	Elec Tran-Line-MN	2,098,520	-	2,098,520
11348062	MNVC0 Ash Pond Removal	Elec Prod-Steam-MN-Minn Valley	(5)	-	(5)
11348066	NSM0748 Line Refurbishment, Line	Elec Tran-Line-MN	1,738,522	-	1,738,522
11348072	NSM0825 Line Refurbishment, Line	Elec Tran-Line-MN	12,145	-	12,145

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11348074	NSPM 2011 S&E, Sub	Elec Tran-Sub-MN	422,297	-	422,297
11348111	NSPM 2012 S&E, Sub	Elec Tran-Sub-MN	696,781	-	696,781
11348119	NSPM 2013 S&E, Sub	Elec Tran-Sub-MN	-	847,011	847,011
11348126	NSP COM Tool, 2011	General Plant-MN	385,400	-	385,400
11348159	0868 Sauk River-SCL Inland Out Line	Elec Tran-Line-MN	1,937	-	1,937
11348186	CAPX La Crosse N/S Roch-N.Hill	Elec Tran-Line-MN	-	7,909,940	7,909,940
11348193	CAPX La Crosse N/S Roch-N.Hill	Elec Tran-Line-MN	1,549,200	199,400	1,748,600
11348236	Scot County Sub Term, Sub	Elec Tran-Sub-MN	-	3,546,429	3,546,429
11348242	Winthrop Bus Protection, Sub	Elec Tran-Sub-MN	4,514	-	4,514
11348324	GDMC0 Gearbox Repl 2013	Elec Prod-Other-MN-Grand Meadow	-	1,196,747	1,196,747
11348542	HBC0C Riding Floor Scrubber	Elec Prod-Other-MN-High Bridge-MERP	45,934	-	45,934
11348546	HBC7C U7 CT Spin Cool Alternat	Elec Prod-Other-MN-High Bridge-MERP	635,187	-	635,187
11348548	Meadowlake Substation, Land	Elec Tran-Sub-MN	1,274,318	-	1,274,318
11348592	SHC3C Boiler Section Repl 2020	Elec Prod-Steam-MN-Sherburne	178,605	-	178,605
11349172	HNIC1 Replace Underground Cable	Elec Prod-Hydro-MN-Hennepin ISD	-	242,955	242,955
11349185	HNIC1 Replace Trash Racks	Elec Prod-Hydro-MN-Hennepin ISD	-	367,012	367,012
11349243	SER0C -RTC 2012 Tools	General Plant-MN	28,067	4,815	32,882
11349251	SER0C -RTC 2013 Tools	General Plant-MN	-	29,998	29,998
11349511	REW0C ASH BUILDING REPLACEMENT	Elec Prod-Steam-MN-Red Wing	406,153	-	406,153
11349686	WLM0C Roof Replacements	Elec Prod-Steam-MN-Wilmarth	457	-	457
11349694	WLM2C U2 Duct Work Repl	Elec Prod-Steam-MN-Wilmarth	337,808	-	337,808
11349698	WLM2C Baghouse Bag Replacement	Elec Prod-Steam-MN-Wilmarth	114,466	-	114,466
11349706	Champlin Road Improvement Douglas	Elec Dist-Mass-MN	(96)	-	(96)
11349731	RIV0C-Cntr Link Install St Ant	Elec Prod-Other-MN-Riverside-MERP	89,814	-	89,814
11349753	RIV0C-Plant Security	Elec Prod-Other-MN-Riverside-MERP	(8,301)	-	(8,301)
11349757	RIV7C-U7 Turb Emergency Trip S	Elec Prod-Other-MN-Riverside-MERP	169,408	-	169,408
11349790	WLM1C Baghouse Bag Replacement	Elec Prod-Steam-MN-Wilmarth	124,274	-	124,274
11349797	WLM0C Station Battery and Inve	Elec Prod-Steam-MN-Wilmarth	99,546	-	99,546
11349818	WLM0C Reverse Osmosis Skid Rep	Elec Prod-Steam-MN-Wilmarth	76,423	-	76,423
11350229	ASK1C-Coal Handling Slew Boom	Elec Prod-Steam-MN-Allen S King	162,949	-	162,949
11350566	ASK1C-AQCS Bldg Heating Systems	Elec Prod-Steam-MN-Allen S King	(7,709)	-	(7,709)
11350574	ASK1C-Phase 2 Plant Evac System	Elec Prod-Steam-MN-Allen S King	(2,438)	-	(2,438)
11350821	SHCCC U1 2 Boiler CO/NO Analyz	Elec Prod-Steam-MN-Sherburne	551,227	-	551,227
11350828	SHC3C U3 Spray Dryer Chamber L	Elec Prod-Steam-MN-Sherburne	0	-	0
11351342	Hwy 23 Road Move Paynesville	Elec Dist-Mass-MN	42,094	-	42,094
11351394	REW0C SCREEN HOUSE DEWATERING	Elec Prod-Steam-MN-Red Wing	-	23,049	23,049
11351401	REW1C U1 BAGHOUSE BAGS REPLACE	Elec Prod-Steam-MN-Red Wing	151,005	-	151,005

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11351460	BDS0C Cedar Discharge Gates Re	Elec Prod-Steam-MN-Black Dog	(16,630)	-	(16,630)
11351468	BDS0C BD Bridges/Hi Rvr Road &	Elec Prod-Steam-MN-Black Dog	(743)	-	(743)
11351474	Line 0899, Line	Elec Tran-Line-MN	-	569,652	569,652
11351477	New Mayhew-Benton County, Line	Elec Tran-Line-MN	-	3,950,216	3,950,216
11351485	Line 0868, Line	Elec Tran-Line-MN	3,208	-	3,208
11351493	Sauk River, Sub	Elec Tran-Sub-MN	-	33,054	33,054
11351496	Benton County, Sub	Elec Tran-Sub-MN	-	127,724	127,724
11351498	St Cloud, Sub	Elec Tran-Sub-MN	-	106,852	106,852
11351501	Granite City, Sub	Elec Tran-Sub-MN	-	213,734	213,734
11352016	Purch Server for OEP 2009	General Plant-MN	5,001	-	5,001
11353052	Columbia Mall Feeder Extension	Elec Dist-Mass-ND	37,312	-	37,312
11353059	Hwy 494/169 Relocate OH Fdr	Elec Dist-Mass-MN	1,514,640	-	1,514,640
11353257	SHCJC UJ PLC Replacements	Elec Prod-Steam-MN-Sherburne	127,632	-	127,632
11353296	Pomerleau Lake, Land	Elec Tran-Sub-MN	15,000	3,194,000	3,209,000
11353409	Pomerleau Lake to Meadow Lake, ROW	Elec Tran-Line-MN	-	500,000	500,000
11357159	PI Sub CT Relay Project, Sub	Elec Tran-Sub-MN	(660)	-	(660)
11358567	SHC3C U3 Slaking Water Heating	Elec Prod-Steam-MN-Sherburne	6,954	-	6,954
11358755	ITSA Pole GIS SW	Computer Software-MN	374,502	-	374,502
11358788	DataBase SW for GIS ITSA Pole	Computer Software-MN	712,868	-	712,868
11358877	SER0C 11 PMO Wireless Test Tra	General Plant-MN	372	-	372
11358880	SER0C 11 PMO Boiler Camera	General Plant-MN	3,796	-	3,796
11360137	SHCJC Pur Water Jet Cutter	General Plant-MN	6,177	-	6,177
11361763	Install UG Feeders ar Long Lake #2	Elec Dist-Mass-MN	233,176	563,661	796,837
11361768	NSPM Repl Under Frequency Relays	Elec Dist-Sub-MN	9,246	86,417	95,663
11362013	Convert portions of Marshall 4kV	Elec Dist-Mass-MN	304,825	-	304,825
11362016	Main Street Reconf 071 Feeder	Elec Dist-Mass-MN	0	-	0
11362023	Cedar Lk 071 extend feeder	Elec Dist-Mass-MN	1	-	1
11362025	Install new Fdr bay for OsseoOSS077	Elec Dist-Sub-MN	43	-	43
11362027	Install new Osseo feeder OSS077	Elec Dist-Mass-MN	(144,607)	-	(144,607)
11362031	West Rvr Rd new feeder	Elec Dist-Mass-MN	(337)	-	(337)
11362033	Install new Fdr bay for West Rvr Rd	Elec Dist-Sub-MN	128	-	128
11362035	Install new Fdr from Eden Prairie93	Elec Dist-Mass-MN	524,871	-	524,871
11362038	Inst Eden Prairie TR4-TR2 bus tie	Elec Dist-Sub-MN	1,938,414	-	1,938,414
11363171	Install Lincoln County TR8, 50 MVA	Elec Dist-Sub-SD	58	-	58
11363172	Parallel WSF062 cable in duct line	Elec Dist-Mass-SD	15,422	-	15,422
11363173	Tie to WSF065 on Kiwanis & 13th	Elec Dist-Mass-SD	61,965	-	61,965
11363178	Req dist move due to phase 1- SWTC	Elec Dist-Mass-MN	1,037,068	1,391,419	2,428,487

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11363179	Req dist move due to phase2 -SWTC	Elec Dist-Mass-MN	-	482,881	482,881
11363180	Transfer Plato load - sub	Elec Dist-Sub-MN	-	1,688,031	1,688,031
11363182	Replace Ductline Snelling Ave.	Elec Dist-Mass-MN	1,055,682	-	1,055,682
11363201	Line 0704 West Hastings to Redwind,	Elec Tran-Line-MN	7,909	-	7,909
11364155	GIS Transmission Ph 2 MN	Computer Software-MN	1,255,243	-	1,255,243
11366598	NSPM Spare 345-115 Transformer, Sub	Elec Tran-Sub-MN	3,360,062	-	3,360,062
11366603	Inver Hills - Rplace TR9, Sub	Elec Tran-Sub-MN	3	-	3
11366605	Line 0844 Black Dog-Savage, Line	Elec Tran-Line-MN	-	7,618,489	7,618,489
11366761	MNGP 4 KV HELB Room Barrier	Elec Prod-Nuclear-MN-Monticello	2,514,595	6,476	2,521,071
11366774	MNGP Purch spare CRDH Pump Mtr	Elec Prod-Nuclear-MN-Monticello	-	150,911	150,911
11366884	MNGP Rplc NON 1E Inverter, Y-9	Elec Prod-Nuclear-MN-Monticello	-	488,761	488,761
11366893	MNGP Reactor Vessel Incore Dry	Elec Prod-Nuclear-MN-Monticello	-	952,265	952,265
11367385	NSPM C Corp Sec Ntwk	General Plant-MN	133,763	3,616	137,379
11367571	NBLC0 Condition Monitoring Sys	Elec Prod-Other-MN-Nobles Wind	1,709,627	-	1,709,627
11367661	MNGP Met Tower Lightning Prot	Elec Prod-Nuclear-MN-Monticello	856,997	25,301	882,298
11367663	MNGP HAYS 02 Monitor Rplc	Elec Prod-Nuclear-MN-Monticello	545,438	25,939	571,377
11368101	PI Force On Force Modifications	Elec Prod-Nuclear-MN-Prairie Island	516,250	-	516,250
11368106	PI River Temp Monitoring Sys	Elec Prod-Nuclear-MN-Prairie Island	471,835	-	471,835
11368110	PI U1 ECCS Venting Sys GL0801	Elec Prod-Nuclear-MN-Prairie Island	(52,401)	-	(52,401)
11368189	MNGP Upgrade Old Whse 5	Elec Prod-Nuclear-MN-Monticello	2,647	-	2,647
11368236	PI Hot Lab Electrical Upgrades	Elec Prod-Nuclear-MN-Prairie Island	-	619,983	619,983
11368301	NSPM E Corp Sec Ntwk	General Plant-MN	286,284	153,446	439,730
11373772	SHC3C U3 2016 Mill OH Repl Pul	Elec Prod-Steam-MN-Sherburne	6,269	-	6,269
11379851	Chestnut SC Elevator Upgrade	Office, Service & Other Bldgs-MN	925	-	925
11379854	Maple Grove Garage & Bldg K	Office, Service & Other Bldgs-MN	7,658,163	-	7,658,163
11379857	Montrose Building	Office, Service & Other Bldgs-MN	13,796	-	13,796
11381177	SHC1C U1 SUS Cable Repl	Elec Prod-Steam-MN-Sherburne	37,403	-	37,403
11382113	BS-Fcst-BD-NW-CM-M	General Plant-MN	709,509	1,881,264	2,590,773
11382151	BS-Fcst-LRR-SW-CM-M	Computer Software-MN	387,228	947,126	1,334,354
11382159	H102-Wahpeton Sub Wave Trap, Sub	Elec Tran-Sub-ND	(73,046)	-	(73,046)
11382164	ND T-Line EOL Rplmnts Phase 2	Elec Tran-Line-ND	38,712	-	38,712
11382170	SD T-Line EOL Rplmnts Phase 2, Line	Elec Tran-Line-SD	65,478	-	65,478
11382243	BS-Fcst-ITS-NW-CM-M	General Plant-MN	107,065	1,270,667	1,377,732
11382280	BS-Fcst-ITS-SW-CM-M	Computer Software-MN	352,684	1,949,929	2,302,612
11383584	0824 SCL-Wakefield I-94 X-ing, 0973	Elec Tran-Line-MN	74	-	74
11383604	NSP Spare 230-115 Transformer, Sub	Elec Tran-Sub-MN	(183,652)	-	(183,652)
11383932	G971 - Adams Wind, Sub	Elec Tran-Sub-MN	(62,754)	-	(62,754)

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11384687	LC 0822-RMT-CAF-LIDAR,Model,PhRaise	Elec Tran-Line-MN	27,584	-	27,584
11385076	North Mankato Line 5402 Kelso, Line	Elec Tran-Line-MN	2,387	-	2,387
11385343	LC Roseau Cty Rpl 500kV CT s&CCVT s	Elec Tran-Sub-MN	262,477	-	262,477
11386445	LC 0978 MNN-PKL-LiDAR,Model,Interse	Elec Tran-Line-MN	(1,624)	-	(1,624)
11386456	LC 0867 DGC-MP Interconnect-LiDAR,M	Elec Tran-Line-MN	(65)	-	(65)
11386494	LC 0902-MP Interconnect,LiDAR,	Elec Tran-Line-MN	2,940,115	-	2,940,115
11386651	LC 0994-ASK-CHI,LiDAR,Model,Interse	Elec Tran-Line-MN	(1,079)	-	(1,079)
11386663	LC 0890-GRC-XRD,LiDAR,Model,Phase R	Elec Tran-Line-MN	(591)	-	(591)
11386703	LC 0881-RRK-CGR,LiDAR,Model,Phase R	Elec Tran-Line-MN	1,080	-	1,080
11386730	LC 0921-RRK-0921,LiDAR, Model, Inte	Elec Tran-Line-MN	45	-	45
11386741	LC 0865 RRK-ASK,LiDAR,Model,Phase R	Elec Tran-Line-MN	(52)	-	(52)
11387704	CAPX2020 Monti-Quarry Line,Non Shar	Elec Tran-Line-MN	123,926	-	123,926
11388311	NSP Spare 115-69kV, 112MVA Xfmr, Su	Elec Tran-Sub-MN	6,087	-	6,087
11390395	Line 0723-Switch for G971, Line	Elec Tran-Line-MN	379,513	-	379,513
11391320	WLM1C U1 CO2 Flow Monitoring	Elec Prod-Steam-MN-Wilmarth	(4)	-	(4)
11391324	WLM2C U2 CO2 Flow Monitoring	Elec Prod-Steam-MN-Wilmarth	4	-	4
11392083	TAPS SW MN	Computer Software-MN	1,361,754	-	1,361,754
11393571	Distribution Grid Optimization	Computer Software-MN	217,532	12	217,544
11394160	G685 Danielson Substation	Elec Tran-Sub-MN	(75,701)	-	(75,701)
11394165	Line 0793 - Switch for G685, Line	Elec Tran-Line-MN	377,018	-	377,018
11394185	SWTC PHASE 2 CON & Route Permit, Li	Elec Tran-Line-MN	-	587,385	587,385
11395300	Install Renner sub LAND	Elec Dist-Sub-SD	350,100	-	350,100
11396168	LC 5527-SPK-CHC-Survey, Line	Elec Tran-Line-SD	31,154	-	31,154
11396172	LC 0839-SHY-MDW-RED-MPR-Survey, Lin	Elec Tran-Line-ND	17,762	-	17,762
11396177	LC 0860-MAL-SOR-Survey, Line	Elec Tran-Line-ND	(1,005)	-	(1,005)
11396178	LC 0866-CAS-SHY-MPL-Survey, Line	Elec Tran-Line-ND	(376)	-	(376)
11396376	LC 0871-RIV-WCR-Survey, Line	Elec Tran-Line-MN	(286)	-	(286)
11396382	LC 0887-SCL-BEN-GRC-Survey,Line	Elec Tran-Line-MN	(657)	-	(657)
11396386	LC 5505-RIV-BRP-CNC-Survey,Line	Elec Tran-Line-MN	(526)	-	(526)
11396393	LC 5519-CHI-WYO-HUG-GLK-Survey,Line	Elec Tran-Line-MN	49,059	-	49,059
11396400	LC 5522-ECK-L5506-Survey,Line	Elec Tran-Line-MN	(882)	-	(882)
11396408	LC 5526-RLK-LOK-Survey,Line	Elec Tran-Line-MN	(1,272)	-	(1,272)
11396640	Orono 115kV Conversion, Sub	Elec Tran-Sub-MN	-	2,433,218	2,433,218
11398809	NSPM 3rd Party owned Pole Transfers	Elec Dist-Mass-MN	50,651	150,646	201,297
11402454	LC 0992-SHC-BUL-CNC, Lidar, Line	Elec Tran-Line-MN	1,693	-	1,693
11402461	LC 0805-RIV-ALD, Lidar,Line	Elec Tran-Line-MN	502	-	502
11402465	LC 0873-MST-FST Lidar, Line	Elec Tran-Line-MN	(302)	-	(302)

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Project	Description	Major Location	2012	2013	Grand Total
11402477	LC 0804-RIV-TWL Lidar, Line	Elec Tran-Line-MN	(435)	-	(435)
11402526	LC 0989-BLL-IVH-RRK,Lidar, Line	Elec Tran-Line-MN	(9,488)	-	(9,488)
11402530	LC 5501-RIV-ELP Lidar, Line	Elec Tran-Line-MN	(951)	-	(951)
11402535	LC 0977-ASK-TER Lidar, Line	Elec Tran-Line-MN	(819)	-	(819)
11402536	LC 0996-PKL-GRE Dickenson Lidar, Li	Elec Tran-Line-MN	(1,746)	-	(1,746)
11402570	LC 0984-SHC-CNC-TER Lidar, Line	Elec Tran-Line-MN	66,967	-	66,967
11402573	LC 0985-SHC-CNC Lidar, Line	Elec Tran-Line-MN	(309)	-	(309)
11402576	LC 0879-CHC-Grant Lidar,Phase Raise	Elec Tran-Line-SD	327	-	327
11404338	Drayton-Letellier Fiber Optic, Line	Elec Tran-Line-ND	16,224	-	16,224
11405011	ND Major Storm Recovery Blanke	Elec Dist-Mass-ND	93	0	93
11405950	Winona Wind LLC Interconnection - S	Elec Dist-Sub-MN	(136,139)	-	(136,139)
11405955	Install new HUG312 fdr at Hugo	Elec Dist-Mass-MN	4,369,188	-	4,369,188
11405962	Extend two feeders to Visi	Elec Dist-Mass-MN	22,181	-	22,181
11405963	Install Ducline on Riverside Ave	Elec Dist-Mass-MN	2,025,544	-	2,025,544
11406894	Monticello Sub- 345kV GSU Gen Leads	Elec Tran-Sub-MN	(5,552)	-	(5,552)
11406948	Richfield sewer/trail project	Elec Dist-Mass-MN	278,042	-	278,042
11409965	5503 SPK-CHC-LiDAR,Model,Phase Rais	Elec Tran-Line-SD	(592)	-	(592)
11410368	SHC3C U3 Belt 6 to 7 Chute Rep	Elec Prod-Steam-MN-Sherburne	27,000	-	27,000
11410677	CAPX Hampton-N.Rochester 345kV, N/S	Elec Tran-Line-MN	-	98,000	98,000
11410946	Bird Island-Rpl 69kV Breaker 4N426,	Elec Tran-Sub-MN	1,205	-	1,205
11410961	Cass Cty-SHY&SHY-RED Relaying, Sub	Elec Tran-Sub-ND	777,602	-	777,602
11410965	Cliff Ave-Replace 69kV Breaker 211,	Elec Tran-Sub-SD	161	-	161
11410967	Edina-Replace APT 550, Sub	Elec Tran-Sub-MN	1,282	-	1,282
11410973	Gopher-Replace APT 550, Sub	Elec Tran-Sub-MN	1,581	-	1,581
11410976	Granite City-Replace APT 550,	Elec Tran-Sub-MN	1,190	-	1,190
11410982	King-LLK & WLR Relaying, Sub	Elec Tran-Sub-MN	911,560	-	911,560
11410988	Lexington - Replace APT 550, Sub	Elec Tran-Sub-MN	2,247	-	2,247
11411000	Main Street - Replace APT 550, Sub	Elec Tran-Sub-MN	36,044	-	36,044
11411008	Oakdale - LLK Relaying, Sub	Elec Tran-Sub-MN	294,589	-	294,589
11411010	Oakdale - Replace APT 550, Sub	Elec Tran-Sub-MN	656	-	656
11411012	Parkers Lake-Rpl 15kVReactor Breake	Elec Tran-Sub-MN	77,506	-	77,506
11411082	Reinforce Mayville regulators MAY21	Elec Dist-Sub-ND	11	-	11
11411089	Transfer Hollydale to GSL342	Elec Dist-Mass-MN	138,586	-	138,586
11411226	Prairie-Replace APT 550, Sub	Elec Tran-Sub-ND	31,562	-	31,562
11411234	Red River-MPR&CAS-SHY Relaying, Sub	Elec Tran-Sub-ND	853,084	-	853,084
11411239	Red River-Replace APT 550, Sub	Elec Tran-Sub-ND	175,541	-	175,541
11411242	Sheyenne-CAS & CAS-RED Relaying,Sub	Elec Tran-Sub-ND	876,400	-	876,400

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Project	Description	Major Location	2012	2013	Grand Total
11411245	Wilson-Rpl 115kV Breaker 5M167,Sub	Elec Tran-Sub-MN	526,663	-	526,663
11411273	NSM 0714-Rapidan -Mountain Lk Pole,	Elec Tran-Line-MN	5,696	-	5,696
11411296	NSM 0752-Paynesville Trans to Lowry	Elec Tran-Line-MN	1,121	-	1,121
11411321	NSM 0753-Dodge Center to Kenyon, Li	Elec Tran-Line-MN	1,152	-	1,152
11411332	NSM 0761-Mazepa Tap-West Albany, L	Elec Tran-Line-MN	5,831	-	5,831
11411347	NSM 0794-Black Oak to Douglas Cty,	Elec Tran-Line-MN	1,121	-	1,121
11411387	MNGP Appen R Hot Shorts Cble R	Elec Prod-Nuclear-MN-Monticello	1,074,859	-	1,074,859
11411510	0706 Nerstand,MN replace SW 177&178	Elec Tran-Line-MN	(49,551)	-	(49,551)
11411542	0712 Cannon Falls,MN SW150&151,Line	Elec Tran-Line-MN	4,667	-	4,667
11411543	0719 Essig,MN replace SW 321&322,Li	Elec Tran-Line-MN	49,661	-	49,661
11411547	0721 Gibbon,MN replace SW4S17&4S172	Elec Tran-Line-MN	250,113	-	250,113
11411550	0756 Maynard, MN replace SW 425, Li	Elec Tran-Line-MN	(330)	-	(330)
11411556	0790 Cokato, MN replace SW 111&367,	Elec Tran-Line-MN	271,723	-	271,723
11412601	G971-AWG Substation, Commuication,S	Elec Tran-Sub-MN	(38,658)	-	(38,658)
11412652	G685-DLS Substation Communication,	Elec Tran-Sub-MN	(34,527)	-	(34,527)
11412928	WIN 2000 SW MN	Computer Software-MN	9,974	-	9,974
11413007	NSM 0909-Audubon to Baddoura, Line	Elec Tran-Line-MN	3,305,718	-	3,305,718
11414687	NSPM Spare 115-69kV,70 MVA Xf	Elec Tran-Sub-MN	683,303	-	683,303
11415365	St Cloud,Remote End work for Quarry	Elec Tran-Sub-MN	1,160,900	-	1,160,900
11415369	Sauk River-Remote End work, Quarry,	Elec Tran-Sub-MN	3,608	-	3,608
11415477	NSM 0730-Souix Falls to Cliff Ave,	Elec Tran-Line-SD	2,530	-	2,530
11415489	NSM 0768-South to Hatton, Line	Elec Tran-Line-ND	16,542	-	16,542
11415491	NSM 0786-Grand Forks WAPA-GF Steam,	Elec Tran-Line-ND	2,313	-	2,313
11416532	Line 0711 Tap H061Switching Station	Elec Tran-Line-MN	8,709	-	8,709
11418744	Vasa sub for H061 Wind, Land	Elec Tran-Sub-MN	(25,597)	-	(25,597)
11418747	Vasa Sub for H061 Wind, Sub	Elec Tran-Sub-MN	(118)	-	(118)
11420602	Broadway (Forest Lake) OH-UG	Elec Dist-Mass-MN	52,001	-	52,001
11420656	Reserve 70MVA 115-35kV Transformer	Elec Dist-Sub-MN	96,830	-	96,830
11420660	New Ductline on 5th btwn Broadway &	Elec Dist-Mass-MN	889,605	-	889,605
11423066	Replace Failed GSLTR08	Elec Dist-Sub-MN	21	-	21
11423462	Convert Orono to 115 kV	Elec Dist-Sub-MN	425,813	2,506,953	2,932,766
11423506	Install feeder load monitoring	Elec Dist-Sub-MN	4,136	-	4,136
11423510	Install tie CHC311-LAW321	Elec Dist-Mass-SD	49,893	-	49,893
11423878	Hiawatha Project Pre Construction,	Elec Tran-Line-MN	-	3,265,002	3,265,002
11424836	MNGP RHR & Core Spray Cable Re	Elec Prod-Nuclear-MN-Monticello	-	1,557,194	1,557,194
11426403	Install a 50MVA 115/13.8 kV transfo	Elec Dist-Sub-MN	16,458	1,538,381	1,554,840
11426525	ITSM Ph1 SW MN	Computer Software-MN	2,050,502	-	2,050,502

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Project	Description	Major Location	2012	2013	Grand Total
11427032	Repl failed TR1 St Cloud	Elec Dist-Sub-MN	111	-	111
11427707	Quarry Sub, Ph 2, 345kV Non Shared,	Elec Tran-Sub-MN	-	3,417,124	3,417,124
11427844	WLM0C Control and ID Fan Room	Elec Prod-Steam-MN-Wilmarth	(713)	-	(713)
11427992	MNGP Low Degraded Voltage Motor Ter	Elec Prod-Nuclear-MN-Monticello	(682)	-	(682)
11428062	MNGP Turbine Bldg CRW Mod Trit	Elec Prod-Nuclear-MN-Monticello	303	-	303
11430185	MNGP Purchase Desktop PC s	General Plant-MN	60,185	-	60,185
11434783	GIST-II Computer Software, NSPM	General Plant-MN	1,450,063	590,421	2,040,484
11434874	Upgrd RMT311 brkr for UMORE Wind Tu	Elec Dist-Sub-MN	2,065	-	2,065
11437578	Sioux Falls SC Renovation	General Plant-SD	34,582	-	34,582
11438090	Regulatory Process Standard SW MN	Computer Software-MN	-	186,074	186,074
11438153	Enterprise Purge and Archive SW MN	Computer Software-MN	-	376,357	376,357
11438259	OAM Account Mgmt Phase 2 SW MN	Computer Software-MN	(166)	-	(166)
11441769	FST TR04 Failed Transformer	Elec Dist-Sub-MN	32,371	-	32,371
11442636	Reconductor SOR060 feeder in Minot	Elec Dist-Mass-ND	46	-	46
11443924	Line 0870 sale of ROW	Elec Tran-Line-MN	2,242	-	2,242
11447173	Underwood Substation for Lake City,	Elec Tran-Sub-MN	36,693	-	36,693
11448342	Merriam Park TR2	Elec Dist-Sub-MN	51,192	-	51,192
11449228	PI U1 SR Battery Charger Repl	Elec Prod-Nuclear-MN-Prairie Island	21,330	-	21,330
11450088	NSPM Wind AGC RTU, Communication, S	General Plant-MN	558,929	-	558,929
11451086	Purch Server OES Project MN	General Plant-MN	19,525	-	19,525
11451851	ISOC - Interruptible Service Option	Elec Dist-Sub-MN	3,184	-	3,184
11451896	Line 0836 Pole Trussing, Line	Elec Tran-Line-MN	1,152	-	1,152
11451897	Line 0833 Pole Trussing, Line	Elec Tran-Line-MN	1,180	-	1,180
11451902	Line 0830 Pole Trussing, Line	Elec Tran-Line-MN	1,157	-	1,157
11451949	Line 0754 Pole Trussing, Line	Elec Tran-Line-MN	1,213	-	1,213
11451963	Line 0750 Pole Trussing, Line	Elec Tran-Line-MN	1,121	-	1,121
11451965	Line 0746 Pole Trussing, Line	Elec Tran-Line-ND	2,313	-	2,313
11451968	Line 0736 Pole Trussing, Line	Elec Tran-Line-MN	1,121	-	1,121
11451976	Line 0735	Elec Tran-Line-MN	2,241	-	2,241
11453014	Primavera new version P6.8 MN	Computer Software-MN	833,172	-	833,172
11453550	Franchise Renewal Elec	Elec Dist-Mass-MN	147,261	-	147,261
11457414	0912-C002 Drayton-Letellier, Capacity	Elec Tran-Line-ND	361	-	361
11457773	SD 2011 S&E B, Line	Elec Tran-Line-SD	26,530	-	26,530
11457780	PI 121 Cng Water Pump Rebuild	Elec Prod-Nuclear-MN-Prairie Island	763,166	-	763,166
11458339	IEM EMS SW MN	Computer Software-MN	1,544,730	-	1,544,730
11458855	Purch Web Security Gateway App	General Plant-MN	27,317	-	27,317
11459798	RPAM Landworks MN	Computer Software-MN	279,790	-	279,790

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Project	Description	Major Location	2012	2013	Grand Total
11461206	Tool Blanket MN, Line	General Plant-MN	194,315	-	194,315
11461265	Cherry Creek-Rpl CHC-GRT-MIT Relay,	Elec Tran-Sub-SD	651	-	651
11461268	Grant-Rpl CHC-GRT-MIT Realy, Sub	Elec Tran-Sub-SD	779	-	779
11462022	Trussing Line 0879, ND, Line	Elec Tran-Line-SD	6,106	-	6,106
11462028	Trussing Line 0721 MN, Line	Elec Tran-Line-MN	2,241	-	2,241
11462037	Trussing Line 0717 MN, Line	Elec Tran-Line-MN	1,121	-	1,121
11464319	MNGP 2011 Tools & Equipment Blanket	General Plant-MN	404,211	-	404,211
11464577	Install TR2 at DAN 12kV	Elec Dist-Sub-MN	31,242	-	31,242
11466030	Hennepin Trng ElecTools&Equip	General Plant-MN	75,000	-	75,000
11466216	RPAM Tringa MN	Computer Software-MN	1,180,521	-	1,180,521
11466354	LC 5544-WLM-ESW-Uprate to 4 fps,Lin	Elec Tran-Line-MN	98,000	-	98,000
11466931	Fifth St Pumping Plant, Sub	Elec Tran-Sub-MN	518,175	-	518,175
11467472	MNGP 2013	Elec Prod-Nuclear-MN-Monticello	-	58,978	58,978
11467546	ASK1C-Cooling Tower Cell Repla	Elec Prod-Steam-MN-Allen S King	(240)	-	(240)
11467670	Hwy 212 Corridor Permitting	Elec Tran-Line-MN	-	475,084	475,084
11468318	5306 Pleasant Valley to Byron, ROW	Elec Tran-Line-MN	15,829	-	15,829
11468481	MNGP Cyber Security 08-09	Elec Prod-Nuclear-MN-Monticello	-	5,656,375	5,656,375
11469293	BLC: Auto sectionalize switchgear	Elec Dist-Sub-MN	1,463	-	1,463
11471203	NSM 0729-Centerville Rpl SW 829,Lin	Elec Tran-Line-SD	26,422	-	26,422
11477235	Parkers Lake-Replace APT 550, Sub	Elec Tran-Sub-MN	218,531	-	218,531
11479563	Coon Creek-Repl 345kV Relay, Sub	Elec Tran-Sub-MN	6,344	-	6,344
11479564	Terminal-Repl 345kV Relay, Sub	Elec Tran-Sub-MN	20,941	-	20,941
11479566	Chisago County-Repl 345kV Relay, Su	Elec Tran-Sub-MN	10,398	-	10,398
11479914	Danube Distribution Sub Tap, Line	Elec Tran-Line-MN	2,194	-	2,194
11479915	Adams Sub,345kV-50MVAR Reactor, Sub	Elec Tran-Sub-MN	2,460,729	-	2,460,729
11482457	SERV-0-C-CHM0412-AutoCloud/Pr Instr	General Plant-MN	33,000	-	33,000
11482466	SERV-0-C-CHM0513-Oil&Grease An	General Plant-MN	-	31,000	31,000
11482731	ASK0C-CO Detection Install	Elec Prod-Steam-MN-Allen S King	1,124	-	1,124
11482735	Remove Dell Rapids TR2	Elec Dist-Sub-MN	29,714	-	29,714
11482964	CAPX Brookings 0982 WLM-BLL,Line	Elec Tran-Line-MN	45,073	781,100	826,173
11482966	Sheas Lake New 345/115kV, Sub	Elec Tran-Sub-MN	-	15,418,071	15,418,071
11483024	SERV-0C-MTR1301-Vibration data	General Plant-MN	-	49,000	49,000
11483419	FCS Upgrade MN	Computer Software-MN	(1)	-	(1)
11483657	Sheas Lake Sub, Land	Elec Tran-Sub-MN	926	-	926
11483725	CAPX Brookings Lyon Cty, Sub	Elec Tran-Sub-MN	-	17,950,546	17,950,546
11483734	CAPX Brookings Helena, sub	Elec Tran-Sub-MN	-	11,677,103	11,677,103
11484450	WLM2C Generator Stator Re-wedg	Elec Prod-Steam-MN-Wilmarth	137,254	-	137,254

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11484454	WLM0C Station Aux 4 Transforme	Elec Prod-Steam-MN-Wilmarth	99,471	-	99,471
11484509	WLM0C Warehouse	Elec Prod-Steam-MN-Wilmarth	99,386	-	99,386
11484513	WLM1C U1 Boiler Sight Glass	Elec Prod-Steam-MN-Wilmarth	30,348	-	30,348
11484519	WLM2C U2 Boiler Sight Glass	Elec Prod-Steam-MN-Wilmarth	30,348	-	30,348
11484754	New Chaska sub - land	Elec Dist-Sub-MN	241,680	-	241,680
11485233	ASK1C-Gas Recirc FanRot Assemb Repl	Elec Prod-Steam-MN-Allen S King	1,735,035	-	1,735,035
11485248	ASK1C-Turbine Control Syst Rep	Elec Prod-Steam-MN-Allen S King	-	1,229,857	1,229,857
11485264	ASK1C-Coal Syst Controls Repla	Elec Prod-Steam-MN-Allen S King	-	1,383,082	1,383,082
11485268	ASK1C-Lift Station Replace	Elec Prod-Steam-MN-Allen S King	145,239	-	145,239
11485279	ASK1C-Hazardous Waste Storage Area	Elec Prod-Steam-MN-Allen S King	252,913	-	252,913
11485290	ASK1C-Waterwall Panel Replacement	Elec Prod-Steam-MN-Allen S King	-	8,045,731	8,045,731
11485299	ASK1C-Dewater Bin Lower Gate R	Elec Prod-Steam-MN-Allen S King	393,419	-	393,419
11485301	ASK1C-Cyclone Inlet Exp Joint Repl	Elec Prod-Steam-MN-Allen S King	414,069	-	414,069
11485310	ASK1C-SCR Catalyst MiddleLayer	Elec Prod-Steam-MN-Allen S King	2,405,432	-	2,405,432
11485325	ASK1C-Bunker Gate Actuators	Elec Prod-Steam-MN-Allen S King	558,492	-	558,492
11485389	BLLC0 U1-4 HMI Hardware Server	Elec Prod-Other-MN-Blue Lake	86,280	-	86,280
11485395	ANSC0 U2-3 Volt Reg Requiremen	Elec Prod-Other-SD-Angus Anson	-	85,792	85,792
11485402	RIV7C-U7 Lube Oil Skid Install	Elec Prod-Other-MN-Riverside-MERP	44,980	-	44,980
11485433	BDS0C 34 Battery Replacement	Elec Prod-Steam-MN-Black Dog	54,360	-	54,360
11485439	BDS3C 3 Battery Replacement	Elec Prod-Steam-MN-Black Dog	30,178	-	30,178
11485443	BDS0C Ergonomic Overhead Troll	Elec Prod-Steam-MN-Black Dog	70,103	-	70,103
11485461	KEYC0 Battery Replacement	Elec Prod-Other-MN-Key City	-	23,032	23,032
11485464	BDS0C 1-2 Uninterruptible Pwr	Elec Prod-Steam-MN-Black Dog	-	437,293	437,293
11485475	BDS0C 1-2 UPS Battery Replacem	Elec Prod-Steam-MN-Black Dog	-	78,019	78,019
11485505	HBC8C Spin Cool Alternative	Elec Prod-Other-MN-High Bridge-MERP	467,500	-	467,500
11485506	HBC7C SCR Blower Replacement	Elec Prod-Other-MN-High Bridge-MERP	-	64,200	64,200
11485507	HBC8C SCR Blower Replacement	Elec Prod-Other-MN-High Bridge-MERP	-	125,635	125,635
11485712	RIV0C-Nitrogen Supply for AuxB	Elec Prod-Other-MN-Riverside-MERP	55,661	-	55,661
11485714	RIV7C-U7 Protective Relays Replace	Elec Prod-Other-MN-Riverside-MERP	190,413	-	190,413
11486742	REW2C BIN 21 AUGER REPLACEMENT	Elec Prod-Steam-MN-Red Wing	83,094	-	83,094
11486748	REW0C GLAND SEAL SYSTEM	Elec Prod-Steam-MN-Red Wing	109,520	-	109,520
11486750	REW0C RECEIVING BUILDING FEED	Elec Prod-Steam-MN-Red Wing	69,107	-	69,107
11486755	REW0C SITE STORM WATER CONTROL	Elec Prod-Steam-MN-Red Wing	206,984	-	206,984
11486771	REW2C BIN 22 AUGER REPLACEMENT	Elec Prod-Steam-MN-Red Wing	80,410	-	80,410
11486783	REW0C C8 CONVEYOR REPLACEMENT	Elec Prod-Steam-MN-Red Wing	112,486	-	112,486
11486788	REW0C TWS DEICING SYSTEM	Elec Prod-Steam-MN-Red Wing	123,649	-	123,649
11486793	REW0C TRUCK UNLOADING HPU	Elec Prod-Steam-MN-Red Wing	87,018	-	87,018

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11486882	BDS5C CT Exhaust Replacement	Elec Prod-Other-MN-Black Dog	13,801,090	-	13,801,090
11487044	WLM1C Burner Management System	Elec Prod-Steam-MN-Wilmarth	-	77,249	77,249
11487048	WLM0C South Stockroom Addition	Elec Prod-Steam-MN-Wilmarth	221,231	-	221,231
11487055	WLM2C U2 Bin 21 Screw Auger Re	Elec Prod-Steam-MN-Wilmarth	-	93,131	93,131
11487672	HNIC0 Replace Plant Ventilatio	Elec Prod-Hydro-MN-Hennepin ISD	-	155,927	155,927
11487675	SHCJC Inst Frozen Coal Hammerm	Elec Prod-Steam-MN-Sherburne	646,262	-	646,262
11487698	SHCJC Dumper Elevator Moderniz	Elec Prod-Steam-MN-Sherburne	298,841	-	298,841
11487728	SHC3C Mill Overhaul Rpl Pulv G	Elec Prod-Steam-MN-Sherburne	-	687,093	687,093
11487736	SHC3C Mill Overhaul Rpl Pulv G	Elec Prod-Steam-MN-Sherburne	316,427	-	316,427
11487746	SHC3C Watr Fill Statn Data Col	Elec Prod-Steam-MN-Sherburne	71,600	-	71,600
11487750	SHC1C Condenser Dogbone Repl	Elec Prod-Steam-MN-Sherburne	81,064	-	81,064
11487752	SHC1C Turbine Deck Lighting Re	Elec Prod-Steam-MN-Sherburne	(13,620)	-	(13,620)
11487760	SHC1C Breeching X-Joint Repl	Elec Prod-Steam-MN-Sherburne	263,639	-	263,639
11487765	SHC2C Air Heater Basket Cold En	Elec Prod-Steam-MN-Sherburne	-	926,918	926,918
11487767	SHC2C Vibratory Feeder Upgrade	Elec Prod-Steam-MN-Sherburne	-	800,753	800,753
11487783	SHCCC Turbine Freight Elev Mod	Elec Prod-Steam-MN-Sherburne	953	-	953
11487786	SHCCC Water Fill Statn Data Co	Elec Prod-Steam-MN-Sherburne	122,117	-	122,117
11487791	SHCCC Bottom Ash Ceramic Pipe	Elec Prod-Steam-MN-Sherburne	715,823	-	715,823
11487793	SHCCC Personnel Warning Sys Up	Elec Prod-Steam-MN-Sherburne	279,731	-	279,731
11487795	SHCCC N Water Fill Station Rpl	Elec Prod-Steam-MN-Sherburne	111,786	-	111,786
11487796	SHCCC U1&2 Scrubber Mod Reheat	Elec Prod-Steam-MN-Sherburne	236,030	-	236,030
11487920	SHCJC Track AFT Rail Repl	Elec Prod-Steam-MN-Sherburne	-	205,995	205,995
11487921	SHCJC Limestone Track Repl	Elec Prod-Steam-MN-Sherburne	-	167,632	167,632
11487926	SHC2C Condenser Dogbone Repl	Elec Prod-Steam-MN-Sherburne	-	181,253	181,253
11487928	SHC3C Mill Overhaul Rpl Pulv G	Elec Prod-Steam-MN-Sherburne	-	346,637	346,637
11487952	REW0C DUCT SCRUBBER INJECTION	Elec Prod-Steam-MN-Red Wing	3,351	-	3,351
11487992	SHC3C U3 Cooling Tower Repl	Elec Prod-Steam-MN-Sherburne	-	14,568,910	14,568,910
11488125	SHC3C Condenser Dogbone Repl	Elec Prod-Steam-MN-Sherburne	35,017	-	35,017
11488156	Black Dog - Replace APT-550, Sub	Elec Tran-Sub-MN	251,202	-	251,202
11488163	Blue Lake - Replace APT-550, Sub	Elec Tran-Sub-MN	173,435	-	173,435
11488173	Cass County - Replace APT-550, Sub	Elec Tran-Sub-ND	233,930	-	233,930
11488178	SHC2C U2 Air Htr Hot Int Baske	Elec Prod-Steam-MN-Sherburne	-	2,097,801	2,097,801
11488179	Cherry Creek - Replace APT-550, Sub	Elec Tran-Sub-SD	196,026	-	196,026
11488184	Daytons Bluff - Repalce APT 550, Su	Elec Tran-Sub-MN	158,232	-	158,232
11488201	Mallard - Replace APT-550, Sub	Elec Tran-Sub-ND	-	122,937	122,937
11488206	Medicine Lake - Replace APT, Sub	Elec Tran-Sub-MN	112,018	-	112,018
11488209	Merriam Park - Replace APT, Sub	Elec Tran-Sub-MN	189,867	-	189,867

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11488240	Monticello - Replace APT-550, Sub	Elec Tran-Sub-MN	249,131	-	249,131
11488260	Ramsey - Replace APT-550, Sub	Elec Tran-Sub-MN	221,031	-	221,031
11488554	Rose Place - Replace APT-550, Sub	Elec Tran-Sub-MN	135,495	-	135,495
11488566	Sheppar Road - Replace APT-550, Sub	Elec Tran-Sub-MN	136,182	-	136,182
11488568	Split Rock - Replace APT-550, Sub	Elec Tran-Sub-SD	293,850	-	293,850
11488575	St Louis Park - Replace APT-550, Su	Elec Tran-Sub-MN	160,113	-	160,113
11488579	Stockyards - Replace APT-550, Sub	Elec Tran-Sub-MN	90,330	-	90,330
11488582	West Sioux Falls - Replace APT-550,	Elec Tran-Sub-SD	219,854	-	219,854
11488647	Chisago Co - 9P1 Gas Breaker, sub	Elec Tran-Sub-MN	894,764	-	894,764
11488733	CapX N. Rochester-Chester, row	Elec Tran-Line-MN	-	468,200	468,200
11488740	CapX N. Rochester-River, row	Elec Tran-Line-MN	1,568,200	3,707,000	5,275,200
11488744	PI AFW Recirc Flow Meter	Elec Prod-Nuclear-MN-Prairie Island	-	731,657	731,657
11488805	CapX Brookings Brookings Cty-b	Elec Tran-Line-MN	5,732	59,900	65,632
11489173	Dundas Dist. Transformer Update,Sub	Elec Tran-Sub-MN	-	1,087,935	1,087,935
11489177	Elm Creek 2nd Bank,Sub	Elec Tran-Sub-MN	-	2,018,427	2,018,427
11489453	MN 2012 Obsolete Breaker Rplmnt Pro	Elec Tran-Sub-MN	902,933	-	902,933
11489481	ND 2012 Obsolete Breaker Rplmnt Pro	Elec Tran-Sub-ND	161,448	-	161,448
11489521	MNGP 2011 Misc Office Furniture	General Plant-MN	2,039	-	2,039
11489749	SD 2012 Obsolete Breaker Rplmnt Pro	Elec Tran-Sub-SD	218,863	-	218,863
11489840	Split Rock Reactor and Breaker, Sub	Elec Tran-Sub-SD	576,329	-	576,329
11489896	NSPM Spare 345-115kV Xfmr, Sub	Elec Tran-Sub-MN	3,511,112	-	3,511,112
11489910	Extend LAW322 to Dell Rapids	Elec Dist-Mass-SD	3,539,338	-	3,539,338
11489968	Forbes 500kv Sub Refurbishment,Sub	Elec Tran-Sub-MN	-	2,577,137	2,577,137
11490028	Lake Caroline Interconnection, Line	Elec Tran-Line-MN	-	304,315	304,315
11490032	Lake Lillian Interconnection,Line	Elec Tran-Line-MN	-	287,368	287,368
11490048	0885 KOL - GLK 115kV DBL Ckt. ROW	Elec Tran-Line-MN	28,455	-	28,455
11490310	ND T-Line ELR 2013, Line	Elec Tran-Line-ND	-	49,069	49,069
11490331	ND T-LineELR 2012, Line	Elec Tran-Line-ND	39,230	-	39,230
11490335	NSPM T-Line ELR 2012, Line	Elec Tran-Line-MN	597,060	-	597,060
11490339	NSPM T-Line ELR 2013, Line	Elec Tran-Line-MN	-	883,244	883,244
11490353	SD T-Line ELR 2012, Line	Elec Tran-Line-SD	34,351	-	34,351
11490375	SD T-Line ELR 2013, Line	Elec Tran-Line-SD	-	49,069	49,069
11490431	Mechanical - Elec	Office, Service & Other Bldgs-MN	2,017	-	2,017
11490438	ND 2012 Reloc B, Line	Elec Tran-Line-ND	68,701	-	68,701
11490440	ND 2013 Reloc B, Line	Elec Tran-Line-ND	-	98,138	98,138
11490464	NSPM 2012 Reloc B, Line	Elec Tran-Line-MN	832,545	-	832,545
11490511	NSPM 2013 Reloc B, Line	Elec Tran-Line-MN	-	1,962,764	1,962,764

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11490523	SD 2012 Reloc B, Line	Elec Tran-Line-SD	68,701	-	68,701
11490528	SD 2013 Reloc B, Line	Elec Tran-Line-SD	-	98,138	98,138
11490540	NSPM 2012 Major Line Refurbishment,	Elec Tran-Line-MN	164,471	-	164,471
11490605	NSPM 2012 Switch Replacements, Line	Elec Tran-Line-MN	9,815	-	9,815
11490614	NSPM 2013 Switch Replacements, Line	Elec Tran-Line-MN	-	294,415	294,415
11490628	NSM 0715 Lake Emily repl SW 369,370	Elec Tran-Line-MN	-	260,758	260,758
11490806	NSM 0723 ? Atwater replace SW	Elec Tran-Line-MN	-	326,069	326,069
11490808	NSM 0723 Cosmos Rpl SW C84 & C85, Li	Elec Tran-Line-MN	497,364	-	497,364
11490832	NSM 0741 ? Atwater replace SW	Elec Tran-Line-MN	-	318,321	318,321
11490848	NSM 0771 ?Lester Prairie rpl SW 408	Elec Tran-Line-MN	-	260,758	260,758
11490853	NSM 0790 - Dassel rpl SW 640,	Elec Tran-Line-MN	-	392,226	392,226
11490856	SHCCC Crusher Elev Ctrl Repl	Elec Prod-Steam-MN-Sherburne	241,512	-	241,512
11490863	NSPM 2012 Major Line Rebuild,	Elec Tran-Line-MN	1,651,209	-	1,651,209
11490895	SHCCC Turn Off Main Rail Repl	Elec Prod-Steam-MN-Sherburne	248,742	-	248,742
11491193	ROW for Sheas Lake 69 kV, ROW	Elec Tran-Line-MN	14,609	-	14,609
11491221	Kohl Lake Overstressed Brkr, Sub	Elec Tran-Sub-MN	443,908	-	443,908
11491227	Wilmarth Overstressed Brkr, S	Elec Tran-Sub-MN	868,501	-	868,501
11491235	Inver Hills Overstressed Brkr, Sub	Elec Tran-Sub-MN	330,143	-	330,143
11491239	Minnesota Valley Overstressed Brkr,	Elec Tran-Sub-MN	570,341	-	570,341
11491522	Orono IN/OUT Tap,Line	Elec Tran-Line-MN	-	1,013,120	1,013,120
11491541	Blue Lake - EDP & PKL Relaying, sub	Elec Tran-Sub-MN	-	600,976	600,976
11491545	Chisago Co - ASK Relaying, sub	Elec Tran-Sub-MN	303,738	-	303,738
11491549	Eden Prairie - BLL & PKL Relaying,	Elec Tran-Sub-MN	-	604,250	604,250
11491553	Elm Creek - PKL Relaying, sub	Elec Tran-Sub-MN	-	298,339	298,339
11491561	Inver Hills - TR9 Relaying, sub	Elec Tran-Sub-MN	-	147,901	147,901
11491565	King - CHI Relaying, sub	Elec Tran-Sub-MN	301,940	-	301,940
11491567	Parkers Lake-BLL, ECK & EDP Relayin	Elec Tran-Sub-MN	-	907,953	907,953
11491572	Red Rock - BCR/RCR Relaying, sub	Elec Tran-Sub-MN	-	298,627	298,627
11491578	Sheyenne - 230 kV Relaying, sub	Elec Tran-Sub-ND	-	395,470	395,470
11491685	ND 2012 S&E B, Line	Elec Tran-Line-ND	122,878	-	122,878
11491704	ND 2013 S&E B, Line	Elec Tran-Line-ND	-	98,138	98,138
11491751	SD 2012 S&E B, Line	Elec Tran-Line-SD	85,278	-	85,278
11491753	SD 2013 S&E B, Line	Elec Tran-Line-SD	-	98,138	98,138
11491780	MN 2012 S&E Relaying, Sub	Elec Tran-Sub-MN	481,891	-	481,891
11491817	MN 2013 S&E Relaying, Sub	Elec Tran-Sub-MN	-	196,276	196,276
11491832	ND 2012 S&E Relaying, Sub	Elec Tran-Sub-ND	138,384	-	138,384
11491867	SD 2012 S&E Relaying, Sub	Elec Tran-Sub-SD	147,210	-	147,210

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11491900	ND 2012 S&E, Sub	Elec Tran-Sub-ND	135,929	-	135,929
11491909	ND 2013 S&E, Sub	Elec Tran-Sub-ND	-	166,835	166,835
11491941	SD 2012 S&E, Sub	Elec Tran-Sub-SD	111,228	-	111,228
11491951	SD 2013 S&E, Sub	Elec Tran-Sub-SD	-	166,827	166,827
11492135	Falls New Sub Asset Swap, Land	Elec Tran-Sub-SD	48,834	-	48,834
11492139	Falls New Sub Transmission ROW	Elec Tran-Line-MN	50,000	-	50,000
11492170	Lawrence (LAW) Sub Asset Swap, Land	Elec Tran-Sub-MN	20,030	-	20,030
11492192	Sioux Falls Northern 115kV, Sub	Elec Tran-Sub-MN	-	554,405	554,405
11492210	Souris UVLS, Sub	Elec Tran-Sub-ND	25,263	-	25,263
11492254	2013 Civil Dept Tool B, Line	General Plant-MN	-	75,000	75,000
11492273	2013 Survey Group Tool B, Line	General Plant-MN	-	50,000	50,000
11492285	2013 Tool Blanket MN, Line	General Plant-MN	-	50,000	50,000
11492325	NSP COM Tool 2012, Sub	General Plant-MN	459,552	-	459,552
11492328	NSP COM Tool 2013, Sub	General Plant-MN	-	1,150,000	1,150,000
11492675	2012 Civil Dept Tool B, Line	General Plant-MN	20,000	-	20,000
11492677	2012 Survey Group Tool B, Line	General Plant-MN	50,000	-	50,000
11492679	2012 Tool Blanket MN, Line	General Plant-MN	10,631	-	10,631
11492688	MN 2012 Unserviceable Breaker Rplmn	Elec Tran-Sub-MN	492,756	-	492,756
11492690	MN 2013 Unserviceable Breaker Rplmn	Elec Tran-Sub-MN	-	564,295	564,295
11492712	ND 2012 Unserviceable Breaker Rplmn	Elec Tran-Sub-ND	84,405	-	84,405
11492728	SD 2012 Unserviceable Breaker Rplmn	Elec Tran-Sub-SD	110,904	-	110,904
11495371	2012 Planned MDT Refresh MN	General Plant-MN	612,345	-	612,345
11496409	Montrose - Replace MTR21 Breaker	Elec Dist-Sub-MN	610	-	610
11496778	Repair failed MS11 mobile substation	Elec Dist-Sub-MN	427,517	-	427,517
11496963	Pathfinder Substation EQ Removal, S	Elec Tran-Sub-SD	256,585	-	256,585
11497623	Souris Replace LV bushing TR1, TR3	Elec Dist-Sub-ND	125,358	-	125,358
11498129	Meter to Mailbox SW MN	Computer Software-MN	493,935	-	493,935
11498308	East River Elec relocate OH	Elec Dist-Mass-SD	(6,299)	-	(6,299)
11500093	New Prague 1 Way Switch, ROW	Elec Tran-Line-MN	10,000	-	10,000
11500094	New Prague Switch, Line	Elec Tran-Line-MN	408,031	-	408,031
11500098	NSM 5401? Wakefield to Annandale P/T	Elec Tran-Line-MN	8,206	-	8,206
11500251	SHC3C Silo CO Detection Syst I	Elec Prod-Steam-MN-Sherburne	14,265	-	14,265
11500256	SHCC Silo CO Detection Syst I	Elec Prod-Steam-MN-Sherburne	11,605	-	11,605
11500279	Aldrich extend ALD fdr	Elec Dist-Mass-MN	246,332	-	246,332
11500283	WRvr Rd-extd WRR81reinf	Elec Dist-Mass-MN	90,666	-	90,666
11500290	FST ntwk#4 move 8MVA-WRR ntwk#1	Elec Dist-Mass-MN	477,251	-	477,251
11500296	Indiana-IDA064 UG Feeder	Elec Dist-Mass-MN	444,221	-	444,221

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11500300	Chaska sub - OH feeder	Elec Dist-Mass-MN	112,345	99,764	212,109
11500303	Reinforce EBL066 feeder ties	Elec Dist-Mass-MN	196,817	-	196,817
11500305	Install 4 Fdrs - Viking Sub	Elec Dist-Mass-MN	-	416,301	416,301
11500306	Eden Pr reinforce new EDP085	Elec Dist-Mass-MN	536,605	-	536,605
11500310	Install Fdr DND071 on Dundas TR2	Elec Dist-Mass-MN	-	197,611	197,611
11500317	Instl new fdr exit Cass County	Elec Dist-Mass-ND	-	566,073	566,073
11500318	Convert Mayville MAY002 feeder	Elec Dist-Mass-ND	185,028	-	185,028
11500320	Install two feeders off of ECK TR#3	Elec Dist-Mass-MN	-	750,356	750,356
11500323	Install new Brooklyn Park feeder	Elec Dist-Mass-MN	768,013	-	768,013
11500325	Extend Coon Creek CNC062	Elec Dist-Mass-MN	576,631	-	576,631
11500327	Install 2 Fdrs from Hollydale Sub	Elec Dist-Mass-MN	-	89,937	89,937
11500330	Install Feeder Woodbury WDY311	Elec Dist-Mass-MN	445,701	-	445,701
11500348	Install DBL082 OH feeder	Elec Dist-Mass-MN	-	297,937	297,937
11500349	Rebuild Shaft Hole & Replace Cables	Elec Dist-Mass-MN	378,585	-	378,585
11500354	Install tie to SOS070	Elec Dist-Mass-SD	93,583	-	93,583
11500356	Install stepdown SRD211	Elec Dist-Mass-MN	56,150	-	56,150
11500358	Install 5 MVA SD - SDs and neutral	Elec Dist-Mass-MN	575,509	-	575,509
11500360	Convert some IND load to SCL	Elec Dist-Mass-MN	373,435	-	373,435
11500362	Reinforce OAD feeder exits	Elec Dist-Mass-MN	228,037	-	228,037
11500365	Parallel GLK feeder cables	Elec Dist-Mass-MN	501,555	-	501,555
11500579	Substation Switch Replacement	Elec Dist-Sub-MN	10,619	-	10,619
11500580	WRRTR02 install new 70MVA xfmr	Elec Dist-Sub-MN	1,409,345	-	1,409,345
11500583	Elliot Park-Reinf TR1-2-3to70MVA	Elec Dist-Sub-MN	-	6,913,112	6,913,112
11500584	Indiana-IDA064 feeder bay	Elec Dist-Sub-MN	384,488	-	384,488
11500585	Fifth St Cable Tunnel Fire Supp Sys	Elec Dist-Sub-MN	231,301	-	231,301
11500586	Land -new Viking Sub	Elec Dist-Sub-MN	-	1,466,756	1,466,756
11500588	Distr Sub Viking TR01	Elec Dist-Sub-MN	-	5,110,532	5,110,532
11500589	Westgate15kV-TR1,2bushing-TR2 bus	Elec Dist-Sub-MN	130,729	-	130,729
11500590	Install Dundas TR2 28MVA 69/13.8kV	Elec Dist-Sub-MN	-	3,017,947	3,017,947
11500592	Instl 3rd 50MVA xfmr Cass Cnty	Elec Dist-Sub-ND	-	2,532,987	2,532,987
11500593	Install larger TR Mayville	Elec Dist-Sub-ND	787,584	-	787,584
11500594	Install Elm Creek TR#3 (115/13.8kV)	Elec Dist-Sub-MN	-	2,956,381	2,956,381
11500595	Install new Brooklyn Park Breaker	Elec Dist-Sub-MN	432,786	-	432,786
11500597	Add Fdr breaker for Woodbury WDY311	Elec Dist-Sub-MN	324,527	-	324,527
11500598	Reinf 23.9kV CNJ TR1	Elec Dist-Sub-SD	-	249,378	249,378
11500599	Reinforce WSF065 reactor	Elec Dist-Sub-SD	128,629	-	128,629
11500601	Install 5 MVA SD - retire EDV sub	Elec Dist-Sub-MN	37,014	-	37,014

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11500602	Reinforce 3 OAD Reactors	Elec Dist-Sub-MN	223,278	-	223,278
11500604	Reinf LEX LV bushing and RAM77 Reg	Elec Dist-Sub-MN	150,635	-	150,635
11500606	Upgrade GLK Reactors	Elec Dist-Sub-MN	564,436	-	564,436
11500667	Sheas Lake Permitting, Line	Elec Tran-Line-MN	43,232	-	43,232
11501671	2012 MDT Unplanned Refresh	General Plant-MN	57,592	-	57,592
11501687	2013 Unplanned MDT Refresh	General Plant-MN	-	45,000	45,000
11501784	Purch MDTs for Construction MN	General Plant-MN	11,558	-	11,558
11502435	PI U2 SI 2-33B Valve GL0801	Elec Prod-Nuclear-MN-Prairie Island	-	590,724	590,724
11502468	PI U2 Turb CV Body 2,4 Rebuild	Elec Prod-Nuclear-MN-Prairie Island	-	571,139	571,139
11502471	PI U1 Turb CV Body 2,4 Rebuild	Elec Prod-Nuclear-MN-Prairie Island	554,888	-	554,888
11502472	PI U2 Turb CV Body 1,3 Rebuild	Elec Prod-Nuclear-MN-Prairie Island	542,505	-	542,505
11502491	PI 2012 Misc Tools & Equipment	General Plant-MN	393,129	-	393,129
11502498	PI 2013 Misc Tools & Equipment	General Plant-MN	-	220,000	220,000
11502509	PI 2012 Misc Minor Improvements	Elec Prod-Nuclear-MN-Prairie Island	223,372	-	223,372
11502510	PI 2013 Misc Minor Improvement	Elec Prod-Nuclear-MN-Prairie Island	-	1,062,433	1,062,433
11502519	PI 2012 Misc Office Furniture	General Plant-MN	60,000	-	60,000
11502521	PI 2013 Misc Office Furniture	General Plant-MN	-	105,000	105,000
11502524	MNGP Steam Dryer Disposal	Elec Prod-Nuclear-MN-Monticello	97	-	97
11502544	PI 2012 I/T Capital Blanket	General Plant-MN	-	140,285	140,285
11502546	PI 2013 I/T Capital Blanket	General Plant-MN	-	275,000	275,000
11502577	PI U2 SR Battery Charger Repla	Elec Prod-Nuclear-MN-Prairie Island	1,868,091	-	1,868,091
11502637	PI Spare Feedwater Pump Motor	Elec Prod-Nuclear-MN-Prairie Island	935,617	-	935,617
11502707	PI Spare Cing Water Pump Motor	Elec Prod-Nuclear-MN-Prairie Island	754,685	-	754,685
11502709	PI Septic System 5 Upgrade	Elec Prod-Nuclear-MN-Prairie Island	251,856	-	251,856
11502872	PI 2012 Roof Replacements	Elec Prod-Nuclear-MN-Prairie Island	227,744	-	227,744
11503264	NSPM Communication Equip-Dist Lines	General Plant-MN	283,316	-	283,316
11503424	MNGP SRM s	Elec Prod-Nuclear-MN-Monticello	2,439,255	150,000	2,589,255
11503435	MNGP Dissolved Gas in Oil 2Rs	Elec Prod-Nuclear-MN-Monticello	-	349,954	349,954
11503439	MNGP Fukushima Modifications	Elec Prod-Nuclear-MN-Monticello	750,924	-	750,924
11503443	MNGP Rplc MSDT Level Controlle	Elec Prod-Nuclear-MN-Monticello	-	290,317	290,317
11503502	MN Mobile TR/Subs Reserve 2012	Elec Dist-Sub-MN	-	1,915,046	1,915,046
11503511	ND Auto Switches and Remote Control	Elec Dist-Mass-ND	2,447,514	-	2,447,514
11503567	West Faribault, Rpl Cap1 Breaker,Su	Elec Tran-Sub-MN	53,918	-	53,918
11503746	MNGP Rplc Power Supplies	Elec Prod-Nuclear-MN-Monticello	198,707	-	198,707
11503764	MNGP Site Access Road Replacem	Elec Prod-Nuclear-MN-Monticello	-	904,995	904,995
11505467	NSM0976 Line Refurbishment,Line	Elec Tran-Line-MN	571,917	-	571,917
11505777	0891-Crossroads(XRD)-W St Cloud,Lin	Elec Tran-Line-MN	379,311	-	379,311

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11505788	0859-Inver Hills(IVH)-Chemolite(CHE	Elec Tran-Line-MN	7,032	-	7,032
11505794	0808-Rogers Lake(RLK)-Highbridge(HB	Elec Tran-Line-MN	50,512	-	50,512
11505804	0881-Red Rock(RRK)-Cottage Grove,Li	Elec Tran-Line-MN	519,101	-	519,101
11505811	0759-Red Wing(REW)-MISS.River, Line	Elec Tran-Line-MN	26,627	-	26,627
11505816	0898-Scott County(SC))-Blue Lake(BL	Elec Tran-Line-MN	62,606	-	62,606
11505819	0832-Dome Pipeline(DOM)-Faribault,L	Elec Tran-Line-MN	91,805	-	91,805
11505820	5526-Rogers Lake(RLK)-Lone Oak,Line	Elec Tran-Line-MN	73,672	-	73,672
11505822	0839-Red River(REW)-Sheyenne,Line	Elec Tran-Line-ND	573,635	-	573,635
11506687	EPM Ph2 Transmission MN	Computer Software-MN	2,488,153	-	2,488,153
11506759	Install #2 at Long Lake normal load	Elec Dist-Sub-MN	-	1,368,115	1,368,115
11507888	PI Facilities Infrastruct Upgr	Elec Prod-Nuclear-MN-Prairie Island	-	1,434,523	1,434,523
11507902	PI Renovate Main Warehouse	Elec Prod-Nuclear-MN-Prairie Island	-	253,986	253,986
11511349	South Dakota - Ug Reinforcemnt	Elec Dist-Mass-SD	-	153,754	153,754
11511483	Line 0982-New Sheas Lake 345kV, Lin	Elec Tran-Line-MN	-	1,378,495	1,378,495
11511488	Line 5406-New Sheas Lake 69kV, Line	Elec Tran-Line-MN	-	961	961
11511494	Line 5407-New Sheas Lake 69kV,Line	Elec Tran-Line-MN	-	(345)	(345)
11511504	Split Rock Relay Replmnt, Sub	Elec Tran-Sub-SD	363,356	-	363,356
11511714	MN Office/Training Equipment	General Plant-MN	18,230	-	18,230
11518446	Prairie Sub Trans Extension,Line	Elec Tran-Line-ND	(370)	-	(370)
11518821	PI 12 FWP Shaft & Impeller Repl	Elec Prod-Nuclear-MN-Prairie Island	1,855	-	1,855
11519100	Altra-Feeder ALT021-SCADA, Comm,Su	Elec Tran-Sub-MN	129,950	-	129,950
11520059	Install New 69:13.8 kV transformer	Elec Dist-Sub-MN	686,313	-	686,313
11520377	SHC3C Inst Elevator Fire Contr	Elec Prod-Steam-MN-Sherburne	99,865	-	99,865
11520380	SHCJC Inst Elevator Fire Contr	Elec Prod-Steam-MN-Sherburne	218,301	-	218,301
11520396	SHCCC River Water PLC Repl	Elec Prod-Steam-MN-Sherburne	327,680	-	327,680
11520400	SHCJC Well Water PLC Repl	Elec Prod-Steam-MN-Sherburne	202,226	-	202,226
11520436	Upgrade Wescott OH Fdr to 13.8 kV	Elec Dist-Mass-MN	345,437	-	345,437
11520997	Purch Audio Web HW Appl MN	General Plant-MN	1,033,222	-	1,033,222
11521115	Capitalized-MN-Sales Tax Rfd - Elec	Elec Dist-Mass-MN	(3,010,692)	(672,345)	(3,683,037)
11521425	Mainframe SW MN	Computer Software-MN	299,876	-	299,876
11521605	Purch Network Equip for GIS MN	General Plant-MN	-	97,574	97,574
11521658	Dayton Bluff-Install DBL082 fdr Bay	Elec Dist-Sub-MN	326,371	-	326,371
11523186	Line 0953 OPGW Installation,Line	Elec Tran-Line-MN	2,536,739	-	2,536,739
11523462	LIMS SW MN	Computer Software-MN	194,800	-	194,800
11524647	Brownnton Loop, Line	Elec Tran-Line-MN	843,600	-	843,600
11524886	Farmington-Rpl breaker 4P37-Sub	Elec Tran-Sub-MN	331	-	331
11525438	Reinf RAM77 Reg	Elec Dist-Sub-MN	69,579	-	69,579

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11525956	HBC7C 71 SCR Blower Replacemen	Elec Prod-Other-MN-High Bridge-MERP	(8,690)	-	(8,690)
11526280	Line 0953 OPGW Install in SD, Line	Elec Tran-Line-SD	704,812	-	704,812
11526428	Line 0826 Pathfinder Sub Bypass, Li	Elec Tran-Line-SD	131,760	-	131,760
11528384	Brownnton Loop Line, ROW	Elec Tran-Line-MN	41,766	-	41,766
11531089	0825 PIP to BRI 115kV Rebuild	Elec Tran-Line-MN	182,881	-	182,881
11531092	0825 LAY to LYC 115kV Rebuild	Elec Tran-Line-MN	46,623	-	46,623
11531099	0825 BRI to LAY 115kV Rebuild	Elec Tran-Line-MN	100,264	-	100,264
11531298	0518 BRI to Bravo 34.5kV, 17m rebui	Elec Tran-Line-MN	10,591	-	10,591
11531307	0520 BRI to Delta-Echo 34.5kV 10.5	Elec Tran-Line-MN	36,868	-	36,868
11531316	0519 BRI to Alpha 34.5kV, 20 mile R	Elec Tran-Line-MN	8,723	-	8,723
11531318	0517 BRI to Charlie 34.5kV, 11 m Re	Elec Tran-Line-MN	(736,745)	-	(736,745)
11531323	0521 BRI- Foxtrot 34.5kV, 13.5 m Re	Elec Tran-Line-MN	(15,268)	-	(15,268)
11531591	BDS3C Coal Bunker Hopper Vib S	Elec Prod-Steam-MN-Black Dog	1,687	-	1,687
11531859	CRS Extend SW Upgrade MN	Computer Software-MN	-	567,923	567,923
11532371	SHC3C U3 Generator Bushing Repl	Elec Prod-Steam-MN-Sherburne	0	-	0
11532375	SHC3C U3 Bottom Ash Drains Repl	Elec Prod-Steam-MN-Sherburne	1,062	-	1,062
11533729	Purch Servers AMAG MN	General Plant-MN	1	-	1
11535541	MNGP Land Exchange	Elec Prod-Nuclear-MN-Monticello	(396)	-	(396)
11535902	PI D1/D2 Transient Electrical Model	General Plant-MN	1,381,202	-	1,381,202
11537318	Line 5557,W.Waconia to Victoria,ROW	Elec Tran-Line-MN	128,965	39,200	168,165
11537321	Line 5552, Glencoe to W.Waconia,ROW	Elec Tran-Line-MN	127,228	49,000	176,228
11537795	Energy Assistance SW MN	Computer Software-MN	560,937	-	560,937
11538679	Enoserv ERO SW MN	Computer Software-MN	135,838	-	135,838
11541690	Purch ESB Server GO MN	General Plant-MN	1,684,291	-	1,684,291
11542240	PI Training Ctr/EOF Upgrades	Elec Prod-Nuclear-MN-Prairie Island	321,997	-	321,997
11542274	PI Training Center Electronics	General Plant-MN	71,190	-	71,190
11542415	Glen Lake Reconfiguration, Sub	Elec Tran-Sub-MN	463,485	9,000	472,485
11543008	NBL0C Gearbox Replacement T111	Elec Prod-Other-MN-Nobles Wind	(35,922)	-	(35,922)
11544327	Replace North Star Steel TR2	Elec Dist-Sub-MN	15,252	-	15,252
11544334	Replace Faribault TR1 due to failur	Elec Dist-Sub-MN	(17)	-	(17)
11544505	WLM0C 1TR, 2XY, & 320 Breaker	Elec Prod-Steam-MN-Wilmarth	475,837	-	475,837
11544750	ASK1C-Governor Valve (Spare Pa	Elec Prod-Steam-MN-Allen S King	577,181	-	577,181
11546279	NSPM Training Facility	Office, Service & Other Bldgs-MN	4,544,786	-	4,544,786
11547469	MaxiProx 5375 Reader	General Plant-MN	7,332	-	7,332
11548304	Viking Sub - Transmission Line 0857	Elec Tran-Line-MN	-	346,761	346,761
11548310	Viking Sub - 70 MVA Xfmr, Sub	Elec Tran-Sub-MN	-	2,098,836	2,098,836
11548986	Purch MN OutState Radio ND	General Plant-ND	13,947	-	13,947

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11548991	Purch MN (SD)Outstate Radios	General Plant-SD	12,391	-	12,391
11549034	Purch Radios Small Plant MN	General Plant-MN	1,015,453	-	1,015,453
11549754	ESC Environmental Compliance S	Computer Software-MN	-	2,529,778	2,529,778
11549906	PI Emergency Siren Narrowbandi	Elec Prod-Nuclear-MN-Prairie Island	353,580	-	353,580
11550814	Purch Network Switch PI MN	General Plant-MN	(23,126)	-	(23,126)
11550937	Win 7 OS Upgrade Nuc MN only	Computer Software-MN	-	3,060,332	3,060,332
11551362	Supply Chain Analytics Data Ma	Computer Software-MN	139,723	-	139,723
11551421	St Cloud Loop - ROW	Elec Tran-Line-MN	397,705	218,000	615,705
11551690	Northfield-Carleton Wind Interconne	Elec Dist-Sub-MN	(44,121)	-	(44,121)
11551891	MNGP B.5.b Equipment	Elec Prod-Nuclear-MN-Monticello	42,470	-	42,470
11552062	PI B.5.b Backup Emerg Diesel Pumps	Elec Prod-Nuclear-MN-Prairie Island	766,356	-	766,356
11553804	0868 WSC-SAK Replace Davit Arms, Li	Elec Tran-Line-MN	9,923	-	9,923
11553809	NSM 0723-Lake Lillian rpl SW338,362	Elec Tran-Line-MN	308,110	-	308,110
11554627	129th OH to UG, Rogers	Elec Dist-Mass-MN	8,109	-	8,109
11554654	BFL001 fdr work	Elec Dist-Mass-MN	140,374	-	140,374
11554664	New feedpoint to Delhi	Elec Dist-Mass-MN	422,006	-	422,006
11554998	Split Rock Sub Relay 0953 OPGW, Sub	Elec Tran-Sub-SD	171,447	-	171,447
11555011	Nobles Sub Relay 0953 OPGW, Sub	Elec Tran-Sub-MN	9,665	-	9,665
11555259	City of Carver(Dahlgren)DCPNew Sub	Elec Tran-Sub-MN	-	613,167	613,167
11555262	Line 0844 Tap city of Carver DCP,Li	Elec Tran-Line-MN	374,408	305,000	679,408
11555323	Upgrade BFL sub from 4kV to 15kV	Elec Dist-Sub-MN	549,123	-	549,123
11555489	G904 Sequoia IA 230kV,Sub	Elec Tran-Sub-ND	22,010	-	22,010
11556086	GIST Ph3 SW MN	Computer Software-MN	-	1,192,276	1,192,276
11556685	MNGP Emerg Siren Narrowbanding	Elec Prod-Nuclear-MN-Monticello	346,173	-	346,173
11558256	MNGP Rpl 2RS-2R Cable	Elec Prod-Nuclear-MN-Monticello	119,393	-	119,393
11558648	SHCJC Rpl Liquid H2 with H2 Ge	Elec Prod-Steam-MN-Sherburne	816,953	-	816,953
11558717	Line 0920 - Tap for G904 Sub, Line	Elec Tran-Line-ND	1,323	-	1,323
11558966	Computing hardware for GIST II, NSP	General Plant-MN	-	67,513	67,513
11559677	PI Site Asphalt Replacement	Elec Prod-Nuclear-MN-Prairie Island	4,442	-	4,442
11559748	HBC0C Lighting Replacement	Elec Prod-Other-MN-High Bridge-MERP	208,162	-	208,162
11559752	HBC0C Purchase Ovation Data Se	Elec Prod-Other-MN-High Bridge-MERP	111,934	-	111,934
11559763	Minot SC Rebuild	Office, Service & Other Bldgs-ND	3,288,770	-	3,288,770
11560088	SharePoint New Version MN	Computer Software-MN	-	1,087,884	1,087,884
11560363	MNGP Spare GSU Transformer	Elec Prod-Nuclear-MN-Monticello	67,692	-	67,692
11560977	PI CT Stop Log Gates	Elec Prod-Nuclear-MN-Prairie Island	171,432	-	171,432
11561445	PI Cooling Tower Storage Pad	Elec Prod-Nuclear-MN-Prairie Island	317,608	-	317,608
11561466	Build a concrete slab for transform	Office, Service & Other Bldgs-MN	5,748	-	5,748

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11562499	J183 Geronimo NetZero Interconnect,	Elec Tran-Sub-SD	3,879	-	3,879
11564273	SHCJC Dumper Rail Car Identifi	Elec Prod-Steam-MN-Sherburne	119,089	-	119,089
11564298	SHC2C Lighting Replacement	Elec Prod-Steam-MN-Sherburne	(17,188)	-	(17,188)
11564303	SHC3C Lighting Replacement	Elec Prod-Steam-MN-Sherburne	72,667	-	72,667
11564305	SHCJC Replace Crane	Elec Prod-Steam-MN-Sherburne	0	-	0
11564905	WLM0C Kaydon Lube Oil Filt Skid	Elec Prod-Steam-MN-Wilmarth	48,317	-	48,317
11565109	ASK1C-VFD Well Pumps Install	Elec Prod-Steam-MN-Allen S King	6,240	-	6,240
11565400	0517 / BRI322 34.5kV Wind, Line	Elec Tran-Line-MN	324,109	-	324,109
11565404	0518 / BRI323 34.5kV Wind, Line	Elec Tran-Line-MN	273,617	-	273,617
11565405	0519 / BRI321 34.5kV Wind, Line	Elec Tran-Line-MN	336,711	-	336,711
11565407	0520 / BRI311 34.5kV Wind, Line	Elec Tran-Line-MN	249,157	-	249,157
11565409	0521 / BRI312 34.5kV Wind, Line	Elec Tran-Line-MN	327,074	-	327,074
11566026	Purch Nuc Workstations PI MN	General Plant-MN	132,538	-	132,538
11566030	Purch Thin Client Workstation	General Plant-MN	3,101	-	3,101
11567370	MNGP Install Simulator Models	General Plant-MN	225,625	-	225,625
11567470	Purch Disaster Recovery HW MN	General Plant-MN	-	8,460,913	8,460,913
11570111	MISO Synchronphaser MN	Communication Site-MN	-	628,445	628,445
11570575	West Creek Substation, Sub	Elec Tran-Sub-MN	1,114,422	-	1,114,422
11572081	MNGP Turbine Bearing Header Lo	Elec Prod-Nuclear-MN-Monticello	(1,506)	-	(1,506)
11572227	PI Training Center Refurnish	General Plant-MN	460,908	-	460,908
11572234	PI Old Security Facility Remodel	Elec Prod-Nuclear-MN-Prairie Island	337,473	-	337,473
11572394	PI Old Security Bldg Furniture	General Plant-MN	6,704	-	6,704
11572876	Repl Phone System Minot ND	General Plant-ND	113,412	-	113,412
11572912	PI Training Center Chiller Repl	Elec Prod-Nuclear-MN-Prairie Island	83,358	-	83,358
11572914	PI Telescop Forklift Cat TL1255	General Plant-MN	144,868	-	144,868
11572927	United Health Data Park	Elec Dist-Mass-MN	56,304	-	56,304
11572930	PI Plant Radio System	General Plant-MN	115,157	-	115,157
11573099	REW0C NATURAL GAS LINE REPLACE	Elec Prod-Steam-MN-Red Wing	47,921	-	47,921
11573102	REW0C MCC700 REPLACEMENT	Elec Prod-Steam-MN-Red Wing	86,082	-	86,082
11573645	ASK1C-Cyclone Flame Scanner Re	Elec Prod-Steam-MN-Allen S King	71,465	-	71,465
11573753	Nobles Sub - Synchronphaser, Comm	General Plant-MN	147	-	147
11573754	Prairie Island Sub - Synchronphaser,	General Plant-MN	57	-	57
11573755	Sherbourne Cty Sub-Synchronphaser, C	General Plant-MN	102	-	102
11573757	Wilmarth Sub - Synchronphaser, Comm	General Plant-MN	93	-	93
11573759	Blue Lake Sub - Synchronphaser, Comm	General Plant-MN	193	-	193
11573760	A.S. King Sub - Synchronphaser, Comm	General Plant-MN	1,399	-	1,399
11573763	Brookings Sub - Synchronphaser, Comm	General Plant-MN	814	-	814

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11573765	Chisago Sub - Synchrophaser, Comm	General Plant-MN	1,332	-	1,332
11573770	Kohlman Lake Sub - Synchrophaser, C	General Plant-MN	265	-	265
11573777	Lakefield Sub - Synchrophaser, comm	General Plant-MN	865	-	865
11573780	Monticello Sub - Synchrophaser, Com	General Plant-MN	245	-	245
11574133	PI Ion Chromatograph	General Plant-MN	10,010	-	10,010
11576144	Replace Merriam Park TR2 (part 2)	Elec Dist-Sub-MN	1,410,126	-	1,410,126
11576406	PI Flow Loop Trainer Lab-Volt 3531	General Plant-MN	(100,677)	-	(100,677)
11576469	Purch Network Servers GO in MN	General Plant-MN	41,632	-	41,632
11576471	Purch Network Servers for GO MN	General Plant-MN	121,138	-	121,138
11576513	PI Remote Camera System	General Plant-MN	8,334	-	8,334
11576525	PI North Whse Heat/Insulate	Elec Prod-Nuclear-MN-Prairie Island	347,821	-	347,821
11577154	BDS0C Trash Racks at Screen House	Elec Prod-Steam-MN-Black Dog	31	-	31
11577857	High Voltage Tester, Sub CO&M,Sub	General Plant-MN	431,200	-	431,200
11578392	Rouseau-Repl 500kV Cap TAGs w/MOV s	Elec Tran-Sub-MN	-	2,127,523	2,127,523
11578721	Purch Red Zone Network Appl MN	General Plant-MN	-	1,455,117	1,455,117
11579460	ERCM Rel 2 SW MN	Computer Software-MN	863,843	-	863,843
11579481	ERCM Rel 3 SW MN	Computer Software-MN	-	229,207	229,207
11579528	5538 BRI-YNK 115kV, Line	Elec Tran-Line-MN	3,318	-	3,318
11579581	NSPMN ES Cap Transportation 20	General Plant-MN	106,388	-	106,388
11580641	ASK0C-Welding Truck	Transportation Equipment-MN	(55,072)	-	(55,072)
11582002	Peace Garden Sub, Land	Elec Tran-Sub-ND	0	-	0
11582008	Line 0716 Easement, ROW	Elec Tran-Line-MN	1,629	-	1,629
11582011	Line 5552 Plato to W. Waconia 115,	Elec Tran-Line-MN	-	1,140,776	1,140,776
11582015	Line 5557 W. Waconia to Aue Lake, L	Elec Tran-Line-MN	-	3,310,284	3,310,284
11582020	Line 5556 W. Creek to Victoria Tap,	Elec Tran-Line-MN	-	763,959	763,959
11582025	Line 5552 Diaond-Plato 115kV, Line	Elec Tran-Line-MN	-	1,144,033	1,144,033
11582170	J183 Geronimo Interc Metering, Sub	Elec Tran-Sub-SD	2,429	-	2,429
11582173	Line 5527 Reterminate IA, Line	Elec Tran-Line-SD	2,702	-	2,702
11582177	Line 5556 W Creek to Victoria,ROW	Elec Tran-Line-MN	215,190	505,000	720,190
11582904	Big Stone-Brookings 345kV Line,ROW	Elec Tran-Line-SD	79,001	60,000	139,001
11582994	IFRS SW MN	Computer Software-MN	-	2,229,559	2,229,559
11583485	2012 EMS Work/Hdwr Annual Refresh M	General Plant-MN	74,507	-	74,507
11583541	2012 Annual Storage Refresh MN	General Plant-MN	772,342	-	772,342
11583618	Capitalized MN Sales Tax Rfd- D-Sub	Elec Dist-Sub-MN	(819,169)	-	(819,169)
11583719	2012 Unplanned Printer Refresh MN	General Plant-MN	7,929	-	7,929
11583790	Eden Prairie-Rpl Bushing on TR9,Sub	Elec Tran-Sub-MN	59,599	-	59,599
11583795	Sheyenne-Rpl Bushings on TR5,Sub	Elec Tran-Sub-ND	100,352	-	100,352

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11584375	Purch EMS DEMS Ph2 HW MN	General Plant-MN	94,405	-	94,405
11586681	Purch Network Data Domain Appl MN	General Plant-MN	28,005	-	28,005
11586869	Mpls-Electric Trouble Tools & Equip	General Plant-MN	30,000	30,000	60,000
11586871	St Paul-Elec TroubleTools & Equip	General Plant-MN	30,000	30,000	60,000
11586873	REMS-Maple Grove	Elec Dist-Mass-MN	47,160	-	47,160
11587133	2012 Line Capacity-MN, Line	Elec Tran-Line-MN	1,971,795	3,162,949	5,134,744
11587980	NSPM Civil Dept -Mats, Line	General Plant-MN	3,000,000	-	3,000,000
11588067	PI Training Ctr Smart Boards	General Plant-MN	171,665	-	171,665
11589327	Purch Network Servers MN	General Plant-MN	45,248	-	45,248
11589360	Lyon County Transmission, ROW	Elec Tran-Line-MN	516	-	516
11589377	Franklin Sub Expansion, Land	Elec Tran-Sub-MN	-	141,514	141,514
11589430	Purch Network Servers ND	General Plant-ND	18,100	-	18,100
11589433	Purch Network Servers SD	General Plant-SD	9,050	-	9,050
11589537	Purch Network DMZ Servers MN	General Plant-MN	55,641	-	55,641
11589865	MNGP Security MOD FOF Tactical	Elec Prod-Nuclear-MN-Monticello	686,478	-	686,478
11590460	Active Directory SW MN	Computer Software-MN	235,612	-	235,612
11592249	GIS Conflation SW MN	Computer Software-MN	127,433	-	127,433
11593558	Intelliteam SG Rollout-ND	Elec Dist-Mass-ND	(13,426)	-	(13,426)
11593565	Install feeder Line From Grant	Elec Dist-Mass-SD	-	112,551	112,551
11594126	UI Jurisdictional Rpt MN	Computer Software-MN	130,248	-	130,248
11594418	Commodity Mgmt Sys Ph 2 MN	Computer Software-MN	3,033,556	-	3,033,556
11594593	Intelliteam SG - Sioux Falls SD	Elec Dist-Mass-SD	54,119	50	54,170
11597730	Brownton Loop, Sub	Elec Tran-Sub-MN	54,913	-	54,913
11598050	NSPMN ES Cap Transportn 2012	General Plant-MN	109,094	-	109,094
11598801	Install Grant 34.5 kV TR	Elec Dist-Sub-SD	10,399	1,463,141	1,473,540
11599358	Service Suite 10 MN	Computer Software-MN	-	905,171	905,171
11599967	LN0736 Birch-May Dist Underbuild, L	Elec Tran-Line-MN	1,326,010	-	1,326,010
11599981	Forbes Sub Install 500 kV Reactor,	Elec Tran-Sub-MN	-	1,578,679	1,578,679
11599992	Forbes Sub SVS Controls, Sub	Elec Tran-Sub-MN	-	6,350,124	6,350,124
11600004	Forbes Sub-Install CCPD & CT s, Sub	Elec Tran-Sub-MN	-	2,095,802	2,095,802
11600010	Nobles Sub-G602 Wind S Interc,Sub	Elec Tran-Sub-MN	17	-	17
11600016	Line 0953 Fiber Insallation, Line	Elec Tran-Line-MN	1,981,774	-	1,981,774
11600023	Nobles Sub Pilot Relaying, Sub	Elec Tran-Sub-MN	191,002	-	191,002
11600523	Comms- WRRTR02-70MVA xfmr	Elec Dist-Sub-MN	110,482	-	110,482
11600524	comms-Viking sub 6 fdrs	Elec Dist-Sub-MN	-	144,446	144,446
11600525	ComLdMon-Elliot Park-TR1-2-3to70MVA	Elec Dist-Sub-MN	143,217	-	143,217
11600708	Plato New 115kV, Sub	Elec Tran-Sub-MN	-	1,828,134	1,828,134

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Project	Description	Major Location	2012	2013	Grand Total
11600735	West Waconia 115kV Sub Term, Sub	Elec Tran-Sub-MN	10,002	-	10,002
11601223	Paynesville Transmission Substation	Elec Tran-Sub-MN	-	727,006	727,006
11602076	CAPX2020 Douglas County,N/S Sub	Elec Tran-Sub-MN	-	106,758	106,758
11602572	Commodity Mgmt Sys Ph 3	Computer Software-MN	137,615	-	137,615
11602676	Purchase Land for Falls Substation	Elec Dist-Sub-SD	440,000	-	440,000
11604834	ITSM Ph2 MN	Computer Software-MN	-	1,774,307	1,774,307
11606123	BDS5C U5 Turbine Row 2 Blades/	Elec Prod-Other-MN-Black Dog	2,164,866	-	2,164,866
11610122	Gladstone - OH - UG road project OA	Elec Dist-Mass-MN	48,942	-	48,942
11610123	HWY 8 Split Pair Project - LIN022	Elec Dist-Mass-MN	77,532	-	77,532
11610124	CapX 2020 SE Distribution Line Move	Elec Dist-Mass-MN	3,569	-	3,569
11610177	SPCC SD Oil Spill Prevention	Elec Dist-Sub-SD	148,392	-	148,392
11610310	New Plato Trans Sub, Land	Elec Tran-Sub-MN	80,956	-	80,956
11610678	BLL0C-U7/8 NERC Protective Relay	Elec Prod-Other-MN-Blue Lake	150,076	-	150,076
11610778	Rice St Phase 2 OH to UG Conversion	Elec Dist-Mass-MN	576,910	-	576,910
11610875	Purchase Red River spare transforme	Elec Dist-Sub-ND	-	1,107,960	1,107,960
11611045	Grant Substation 115kV, Sub	Elec Tran-Sub-SD	-	506,994	506,994
11612695	Indiana Sub-Inst Breakers,Sub	Elec Tran-Sub-MN	-	782,854	782,854
11612697	PI Load Sequencer I/O Card Repl	Elec Prod-Nuclear-MN-Prairie Island	331,954	-	331,954
11612793	Arlington - Relays on Kelso, Sub	Elec Tran-Sub-MN	161,643	-	161,643
11613465	Line 5557 Ave Lake to Augusta 115kV	Elec Tran-Line-MN	-	1,274,630	1,274,630
11613468	Line 5556 West Creek Sub to Scott C	Elec Tran-Line-MN	-	5,260,841	5,260,841
11613470	Line 5557 Augusta Sub to Victoria T	Elec Tran-Line-MN	-	1,068,958	1,068,958
11613472	Line 0740-Aue Lake to GRE kV Retire	Elec Tran-Line-MN	-	3,948,158	3,948,158
11613475	Line 0771-Plato to Diamond 69kV, Li	Elec Tran-Line-MN	-	747,917	747,917
11613477	Line 0771 Plato to Young America 69	Elec Tran-Line-MN	-	755,510	755,510
11613478	Line 0735-Young America to W Waconi	Elec Tran-Line-MN	-	3,253,218	3,253,218
11613482	Line 0735-W Waconia to Carver 69kV,	Elec Tran-Line-MN	-	295,663	295,663
11614009	Operation Config Mgmt SW MN	Computer Software-MN	290,748	-	290,748
11614082	Sheyenne - Fault Recorder, Comm	Elec Tran-Sub-ND	381,520	-	381,520
11614083	Coon Creek - Fault Recorder, Comm	Elec Tran-Sub-MN	147,933	-	147,933
11614086	Monticello - Fault Recorder, Comm	Elec Tran-Sub-MN	376,378	-	376,378
11614092	Parkers Lake - Fault Recorder, Comm	Elec Tran-Sub-MN	149,548	-	149,548
11614095	Prairie - Fault Recorder, Comm	Elec Tran-Sub-ND	110,503	-	110,503
11614106	Split rock - Fault Recorder, Comm	Elec Tran-Sub-SD	-	352,209	352,209
11614112	Easement for NSpm Line Capacity, RO	Elec Tran-Line-MN	12,000	2,000	14,000
11615308	MNGP 2012 Facilities Infrastru	Elec Prod-Nuclear-MN-Monticello	323,377	-	323,377
11617220	Madison Ave Relocation Mankato	Elec Dist-Mass-MN	5,329	-	5,329

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11618328	Kimble to Annandale, Line	Elec Tran-Line-MN	-	2,338,428	2,338,428
11618342	Rapidan-Alliant, Line	Elec Tran-Line-MN	-	1,100,835	1,100,835
11618348	Pipestone to Tracy, Line	Elec Tran-Line-MN	-	1,314,690	1,314,690
11618354	Pipestone to Dell Rapids-Removal, Li	Elec Tran-Line-MN	-	406,845	406,845
11618441	CHM0512-Coulometric KF Analyzer	General Plant-MN	25,000	-	25,000
11618928	0958 Cedar Mountain to Helena, Line	Elec Tran-Line-MN	-	84,190,324	84,190,324
11618931	0956 Lyon Cty to Cedar Mountain, RO	Elec Tran-Line-MN	3,734,923	1,063,700	4,798,623
11618933	5558 Cedar Mountain to Franklin, RO	Elec Tran-Line-MN	58,558	89,300	147,858
11618937	0958 Cedar Mountain to Helena, ROW	Elec Tran-Line-MN	5,731,402	4,118,500	9,849,902
11619060	MNGP 2012-2013 Control Blades	Elec Prod-Nuclear-MN-Monticello	-	2,494,219	2,494,219
11619349	Tools & Equip-Elec-ND	General Plant-ND	16,789	-	16,789
11619686	Midtown Substation, Sub	Elec Tran-Sub-MN	-	5,296,109	5,296,109
11619807	Budget System Upgrade SW MN	Computer Software-MN	-	2,030,934	2,030,934
11620040	REW1C U1 Precip Rem Inst Roof	Elec Prod-Steam-MN-Red Wing	146,783	-	146,783
11620049	Line 5509, Line	Elec Tran-Line-MN	-	417,713	417,713
11620373	REW1C REPLACE 14 BAGHOUSE COMP	Elec Prod-Steam-MN-Red Wing	502,529	-	502,529
11620657	BS-Fcst-OTI-SW-EL-M	Computer Software-MN	-	525,322	525,322
11620754	BS-Fcst-CSR-SW-EL-M	Computer Software-MN	-	1,395,529	1,395,529
11621292	Underbuild on S. Falls T-line	Elec Dist-Mass-SD	-	109,463	109,463
11621511	REW0C REPLACE FURNACE DRAFT TRANSMT	Elec Prod-Steam-MN-Red Wing	56,068	-	56,068
11621512	REW0C REPLACE FUEL TRANSFER CHUTE	Elec Prod-Steam-MN-Red Wing	67,836	-	67,836
11621513	REW1C U1 OFA FAN VFD INSTALLAT	Elec Prod-Steam-MN-Red Wing	74,399	-	74,399
11621514	REW2C U2 OFA FAN VFD INSTALLAT	Elec Prod-Steam-MN-Red Wing	71,524	-	71,524
11621519	Twin Lake Sub, Indiana Sub Breaker, S	Elec Tran-Sub-MN	-	133,693	133,693
11621521	Aldrich Relay, Indiana SUB Breaker,	Elec Tran-Sub-MN	-	133,543	133,543
11622284	BS-Fcst-CSR-NW-CM-M	General Plant-MN	-	482,045	482,045
11622348	BS-Fcst-OTI-COMM-EL-M	General Plant-MN	-	145,033	145,033
11624376	BS-Fcst-BD-NW-EL-M	General Plant-MN	45,071	411,827	456,897
11624406	85th Ave OH to UG	Elec Dist-Mass-MN	90,831	-	90,831
11625280	ASK1C-Install Coal Silo Liners 2012	Elec Prod-Steam-MN-Allen S King	319,006	-	319,006
11625895	MNGP 2012 Site Blanket	Elec Prod-Nuclear-MN-Monticello	506,118	-	506,118
11626228	SHC1C Repl Generator Bushing	Elec Prod-Steam-MN-Sherburne	4,760	-	4,760
11627732	PI U2 Rod Control Phase Cards	Elec Prod-Nuclear-MN-Prairie Island	176,203	-	176,203
11629013	SHC1C U1 WESP Mod Power Xfmr Rep	Elec Prod-Steam-MN-Sherburne	1,290,750	-	1,290,750
11629015	SHC2C U2 WESP Mod Power Xfmr Rep	Elec Prod-Steam-MN-Sherburne	1,168,049	-	1,168,049
11629467	REW0C NO 1 BOILER FEED PUMP REPLACE	Elec Prod-Steam-MN-Red Wing	138,767	-	138,767
11629666	SER0C MTR1201 MN Test Equip	General Plant-MN	45,810	-	45,810

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11629783	New Feeders for Polarfab Semiconduc	Elec Dist-Mass-MN	101,857	-	101,857
11629792	New ATO for Emerson in Eden Prairie	Elec Dist-Mass-MN	24,598	-	24,598
11629870	HBC8C U8 Voltage Regulator	Elec Prod-Other-MN-High Bridge-MERP	-	145,067	145,067
11629876	HBC0C Electric Gator	Elec Prod-Other-MN-High Bridge-MERP	-	14,978	14,978
11629940	HBC9C U9 Voltage Regulator	Elec Prod-Other-MN-High Bridge-MERP	-	146,778	146,778
11629942	ASK1C-AQCS Pressure Washers	Elec Prod-Steam-MN-Allen S King	-	105,071	105,071
11629950	BDS5C CT PilotNozzle Set Spare	Elec Prod-Other-MN-Black Dog	-	108,225	108,225
11629951	BDS5C Hi Eff Air Purifier Elem	Elec Prod-Other-MN-Black Dog	-	113,257	113,257
11629952	BDS2C U2 Gen Protective Relay	Elec Prod-Other-MN-Black Dog	-	90,812	90,812
11629966	ASK1C-Econ Ash Slide Gates	Elec Prod-Steam-MN-Allen S King	-	80,709	80,709
11629968	ASK1C-SDA Atomizer VibrationMonitor	Elec Prod-Steam-MN-Allen S King	-	116,910	116,910
11629970	ASK1C-Control Room ErgonomicUp	Elec Prod-Steam-MN-Allen S King	-	229,943	229,943
11629971	ASK1C-Generator Relay Panel Re	Elec Prod-Steam-MN-Allen S King	-	183,134	183,134
11629973	ASK1C-Cooling Tower Bypass	Elec Prod-Steam-MN-Allen S King	-	387,608	387,608
11629976	ASK1C-Install Coal Silo Liners 2013	Elec Prod-Steam-MN-Allen S King	-	313,642	313,642
11629984	ASK1C-ID Fan BldgRoof AccessInstall	Elec Prod-Steam-MN-Allen S King	-	117,006	117,006
11629985	ASK1C-Yard Switchgr BldgHoist Instal	Elec Prod-Steam-MN-Allen S King	-	117,509	117,509
11629986	ASK1C-11 BFP Cable Replacement	Elec Prod-Steam-MN-Allen S King	-	238,742	238,742
11630530	SHCCC Repl vehicles at plant	Transportation Equipment-MN	-	111,000	111,000
11630550	SHCCC Upgr 1&2 Turb Crane Mod	Elec Prod-Steam-MN-Sherburne	-	196,173	196,173
11630556	SHCCC Repl Turb Bay Crane Buss	Elec Prod-Steam-MN-Sherburne	-	95,698	95,698
11630771	RIV0C-Ovation Training Simulat	Elec Prod-Other-MN-Riverside-MERP	-	561,833	561,833
11630774	RIV7C-Gland Steam Electric Heater	Elec Prod-Other-MN-Riverside-MERP	-	236,284	236,284
11630775	RIV7C-Steam Turbine Casing Heater	Elec Prod-Other-MN-Riverside-MERP	-	186,217	186,217
11630777	RIV0C-Purchase New Forklift	Elec Prod-Other-MN-Riverside-MERP	-	28,025	28,025
11630778	RIV0C-Plant Heat Recirc Project	Elec Prod-Other-MN-Riverside-MERP	-	302,964	302,964
11630779	RIV9C-U9 Varnish Filter Skid I	Elec Prod-Other-MN-Riverside-MERP	-	32,700	32,700
11630780	RIV10C-U10 Varnish Filter Skid	Elec Prod-Other-MN-Riverside-MERP	-	32,700	32,700
11630783	RIV0C-Offline CCW Pump Install	Elec Prod-Other-MN-Riverside-MERP	-	97,697	97,697
11630785	RIV0C-Marshall St. Fence Repla	Elec Prod-Other-MN-Riverside-MERP	-	139,115	139,115
11630789	RIV0C-Frazil Ice Preven Heat Exchr	Elec Prod-Other-MN-Riverside-MERP	-	292,368	292,368
11630791	RIV7C-U7 Relay Room AC Replace	Elec Prod-Other-MN-Riverside-MERP	-	41,217	41,217
11631116	SHC1C U1 Inst Elec Overspeed	Elec Prod-Steam-MN-Sherburne	-	660,540	660,540
11631121	SHC2C U2 Inst Elec Overspeed	Elec Prod-Steam-MN-Sherburne	-	642,189	642,189
11631127	SHC2C U2 Boiler Optimize System	Elec Prod-Steam-MN-Sherburne	-	823,833	823,833
11631132	SHC1C U1 Inst Boiler Optimize Sys	Elec Prod-Steam-MN-Sherburne	-	667,139	667,139
11631144	SHCJC Purch Coal Yard D8 Dozer	General Plant-MN	-	750,000	750,000

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11631307	SER-0-C- SMC- 2013 Vehicles	Transportation Equipment-MN	-	116,000	116,000
11632205	SERV-C-CSC0113-Paint Can Crusher	General Plant-MN	-	29,000	29,000
11632319	IVH3C U 3-4 Enclosure Door Rep	Elec Prod-Other-MN-Inver Hills	-	92,732	92,732
11633886	SER0C-MMR2013 Microscope Epiphot	General Plant-MN	-	30,000	30,000
11633888	SER0C-MMR2013 Pole Camera	General Plant-MN	-	18,000	18,000
11633904	SERV-PMO0313Process Laptop Computer	General Plant-MN	-	5,000	5,000
11633905	SERV-PMO0413 Cooling Tower Test Kit	General Plant-MN	-	40,000	40,000
11634030	WLM0C Replace C9	Elec Prod-Steam-MN-Wilmarth	-	318,448	318,448
11634141	WLM0C Replace Traveling Water Scr	Elec Prod-Steam-MN-Wilmarth	-	199,281	199,281
11634271	REW1C 2 DRUM SUPPORT SLIDE	Elec Prod-Steam-MN-Red Wing	-	86,505	86,505
11634280	WLM1C ID Fan VFD Replacement	Elec Prod-Steam-MN-Wilmarth	-	3,004	3,004
11634297	REW2C U2 2 DRUM SUPPORT SLIDE	Elec Prod-Steam-MN-Red Wing	-	86,505	86,505
11634303	REW0C UPGRADE PLANT AIR SYSTEM	Elec Prod-Steam-MN-Red Wing	-	461,178	461,178
11634310	REW0C UPGRADE CEMS BUILDING	Elec Prod-Steam-MN-Red Wing	-	372,993	372,993
11634316	REW0C DREDGE POND ACCESS ROAD	Elec Prod-Steam-MN-Red Wing	-	28,039	28,039
11634457	WLM2C Burner Management System	Elec Prod-Steam-MN-Wilmarth	-	77,249	77,249
11634460	WLM2C U2 ID Fan VFD Replacemen	Elec Prod-Steam-MN-Wilmarth	-	64,090	64,090
11634463	WLM0C Replace Receiving Gate	Elec Prod-Steam-MN-Wilmarth	-	25,035	25,035
11635985	SHC3C BFPT Overspeed Ctrl Repl	Elec Prod-Steam-MN-Sherburne	139,102	14,160	153,262
11635990	SHC1C SOFA Actuators Repl	Elec Prod-Steam-MN-Sherburne	165,973	-	165,973
11635993	SHC1C Boiler Lighting Repl	Elec Prod-Steam-MN-Sherburne	274,856	-	274,856
11635997	SHC1C Penthouse Insulation Repl	Elec Prod-Steam-MN-Sherburne	42,062	-	42,062
11636472	REW2C DUCT SCRUBBER CONVEYOR	Elec Prod-Steam-MN-Red Wing	-	156,903	156,903
11636497	SHC3C Unit 3 Restoration	Elec Prod-Steam-MN-Sherburne	-	2,941,961	2,941,961
11636551	RIV0C-HVAC Replace-Sp Const Office	Elec Prod-Other-MN-Riverside-MERP	-	9,013	9,013
11636568	RIV0C-Road Replace-Sp Const Of	Elec Prod-Other-MN-Riverside-MERP	-	111,298	111,298
11636571	RIV0C-Roof Replace-Sp Const Office	Elec Prod-Other-MN-Riverside-MERP	-	110,254	110,254
11639197	WCF - Mandates - NSPM	Elec Dist-Mass-MN	-	2,557,344	2,557,344
11642565	Cass County 3rd Dist TR,Sub	Elec Tran-Sub-ND	-	3,427,542	3,427,542
11642602	Line 0717 City of ARL Tap Rlbd, Lin	Elec Tran-Line-MN	-	541,717	541,717
11642608	500MCM Cable Replacement for ND PUC	Elec Dist-Mass-ND	91,704	222,510	314,214
11644295	REW0C SANITARY SEWER AND WATER	Elec Prod-Steam-MN-Red Wing	165,975	-	165,975
11644344	Castle Rock Interconnection, Line	Elec Tran-Line-MN	-	299,071	299,071
11644793	Edina-Rplace Breaker 5M159,Sub	Elec Tran-Sub-MN	-	148,004	148,004
11644795	Gleason Lake-Replace Breaker 5M85,	Elec Tran-Sub-MN	-	148,004	148,004
11644807	Parkers Lake Relaying - DKN(GRE), S	Elec Tran-Sub-MN	-	247,151	247,151
11644839	Red Rock Relaying - STY - AA, Sub	Elec Tran-Sub-MN	-	252,195	252,195

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11644845	Rogers Lake Relaying - STY - AA, Su	Elec Tran-Sub-MN	-	251,272	251,272
11644849	Terminal Relaying - CNC, Sub	Elec Tran-Sub-MN	-	247,151	247,151
11644859	Black Dog - Install Fault Recorder,	Elec Tran-Sub-MN	-	295,523	295,523
11644863	Riverside - Install Fault Recorder,	Elec Tran-Sub-MN	-	302,050	302,050
11644869	Sherco - Replace Fault recorder, Su	Elec Tran-Sub-MN	-	296,009	296,009
11644875	Mallard-Rpl Breakers 5T8, 5T9, 5T1,	Elec Tran-Sub-MN	-	444,467	444,467
11644877	Blue Lake-Rpl Breakers 5M150,5M15,	Elec Tran-Sub-MN	-	444,467	444,467
11644888	MN-2014-Unserviceable Relay, Sub	Elec Tran-Sub-MN	-	505,320	505,320
11644916	Stockyards Relaying - RLK, RRK-AA,	Elec Tran-Sub-MN	-	503,608	503,608
11644928	Sherco Relaying CNC1,CNC2, Sub	Elec Tran-Sub-MN	-	593,411	593,411
11644931	Coon Creek Relay SHC1,SHC3,TER,DKN,	Elec Tran-Sub-MN	-	1,186,409	1,186,409
11645645	ANS0C Gas line launch/receiver	Elec Prod-Other-SD-Angus Anson	395,768	-	395,768
11645705	ANS4C Relay Upgrades	Elec Prod-Other-SD-Angus Anson	58,234	-	58,234
11646678	Viking Sub Fiber Optic, Line	Elec Tran-Line-MN	-	420,464	420,464
11647509	SHC3C U3 2012 Tools and Equip	General Plant-MN	10,620	-	10,620
11648590	Replace RRK TR1 with 50MVA and add	Elec Dist-Mass-MN	-	469,071	469,071
11648593	Replace RRK TR1 with 50MVA	Elec Dist-Sub-MN	-	2,009,266	2,009,266
11648597	Distribution Automation	Elec Dist-Mass-MN	-	233,116	233,116
11648598	Install arrestors in load centers	Elec Dist-Mass-MN	-	142,875	142,875
11648601	Substation Fence Improvement	Elec Dist-Sub-MN	-	223,634	223,634
11648602	Substation Transformer Replacements	Elec Dist-Sub-MN	-	494,374	494,374
11648614	Reserve 69/23 kV 28 MVA Transformer	Elec Dist-Sub-MN	-	521,651	521,651
11648786	EBL074 Install fdr-Polar Fab	Elec Dist-Mass-MN	-	592,370	592,370
11648807	Install tie NOR 32 Fdr	Elec Dist-Mass-MN	-	280,710	280,710
11649186	Extend feeder - part of DLL069	Elec Dist-Mass-MN	-	422,164	422,164
11649236	Convert SOS 4kV to 13.8 kV	Elec Dist-Mass-SD	-	280,710	280,710
11649240	Install Louise new feeder	Elec Dist-Mass-SD	-	280,571	280,571
11649246	Install SD to service NWL sub load	Elec Dist-Mass-MN	-	281,711	281,711
11649247	Reinforce SDX TR1	Elec Dist-Sub-MN	-	1,006,699	1,006,699
11649251	Upgrade Freeport sub to 12.5 kV	Elec Dist-Sub-MN	-	1,124,093	1,124,093
11649253	Freeport distribution conversion	Elec Dist-Mass-MN	-	471,464	471,464
11649517	Retire Subs in MN	Elec Dist-Sub-MN	(39,159)	44,439	5,280
11649860	MNGP 2013 Site Blanket	Elec Prod-Nuclear-MN-Monticello	-	1,797,940	1,797,940
11649876	MNGP 2013 Plant Computer Blanket	Elec Prod-Nuclear-MN-Monticello	-	51,587	51,587
11650006	RIV0C-VT2 Transformer U9/10 Re	Elec Prod-Other-MN-Riverside-MERP	22,205	-	22,205
11650012	BDS3C Expansion Joints on Precip	Elec Prod-Steam-MN-Black Dog	40,099	-	40,099
11650242	HBC8C Row 2 Turbine Blades	Elec Prod-Other-MN-High Bridge-MERP	1,378,959	-	1,378,959

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11650488	MNGP 2013 Facilities Infrastructure	Elec Prod-Nuclear-MN-Monticello	-	309,522	309,522
11650623	MNGP Thermal Cameras	Elec Prod-Nuclear-MN-Monticello	-	50,709	50,709
11650635	MNGP A509-X301/1Cable Replc	Elec Prod-Nuclear-MN-Monticello	-	82,999	82,999
11650696	MNGP Turbine Building Roof	Elec Prod-Nuclear-MN-Monticello	-	1,358,384	1,358,384
11650740	MNGP Restore Intake Sprinkler Pipin	Elec Prod-Nuclear-MN-Monticello	-	689,130	689,130
11650827	PI Cooling Wtr Supprt 2-CWH-36	Elec Prod-Nuclear-MN-Prairie Island	-	509,380	509,380
11650833	PI LR Ph II-RV Supp Stiffness U1	Elec Prod-Nuclear-MN-Prairie Island	-	509,309	509,309
11651001	MNGP HWC MOD	Elec Prod-Nuclear-MN-Monticello	-	200,551	200,551
11651142	MNGP Filtration Unit (VU-1)	Elec Prod-Nuclear-MN-Monticello	-	100,353	100,353
11651577	MNGP PAB Chemistry Area	Elec Prod-Nuclear-MN-Monticello	-	202,835	202,835
11651585	MNGP I&C Shop Equipment	Elec Prod-Nuclear-MN-Monticello	-	201,523	201,523
11652614	MNGP Nuclear Channels R26 (C27	Elec Prod-Nuclear-MN-Monticello	-	2,429,336	2,429,336
11652655	MNGP Installation Monitoring Wells	Elec Prod-Nuclear-MN-Monticello	61,044	-	61,044
11652667	MNGP 2013 Capital Emergent Work	Elec Prod-Nuclear-MN-Monticello	-	1,031,740	1,031,740
11656020	OMMS12-01 Rolling Filing Unit Add	General Plant-MN	11,978	-	11,978
11662997	RIV0C Emergent work	Elec Prod-Other-MN-Riverside-MERP	71,543	175,950	247,493
11663001	SHCCC Emergent work	Elec Prod-Steam-MN-Sherburne	357,716	879,751	1,237,467
11663004	HBC0C Emergent work	Elec Prod-Other-MN-High Bridge-MERP	71,543	175,950	247,493
11663007	ASK1C-Emergent work	Elec Prod-Steam-MN-Allen S King	214,629	527,851	742,480
11666734	MNGP ROMUD Softeners Replacement	Elec Prod-Nuclear-MN-Monticello	133,873	-	133,873
<b>Grand Total</b>			<b>591,736,092</b>	<b>1,533,295,063</b>	<b>2,125,031,154</b>

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Xcel Energy

Case No.: PU-12-813

Response To: North Dakota Public Service Commission Data Request No. NDPSC-5-086

Requestor: Snavely King Majoros & Associates

Date Received: March 29, 2013

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Question:

Witness: Stephen R. Foss-Operations and System Improvements (Exhibit SRF-1)

Please refer to page 19 of the Foss Testimony which indicates Transmission Capital Additions for 2012 and 2013. Please provide a breakdown of these additions showing a breakdown by Company jurisdictional operations. Provide the total costs to be placed in service, location and completion date.

Response:

As noted on page 19 of Mr. Foss' Testimony, we expect to add \$141.7 million of new transmission plant in-service in 2012 and \$329.1 million in 2013. Like Energy Supply projects, these Transmission projects are budgeted at the NSPM System level since they benefit the entire NSPM System. The portion allocated to the ND jurisdiction (net of Interchange Agreement billings to NSPW) is \$7.2 million for 2012 additions and \$16.8 million for 2013 additions.

Please also see NDPSC-5-020, Attachment A for a listing of capital additions in 2012 and 2013 including project name and location or NDPSC-5-074, Attachment C for a listing of transmission additions greater than \$1 million in 2013. Jurisdictional amounts for any given project can be approximated by multiplying the total company amount by 5.1121%, which represents the ND demand allocator net of billings to NSPW through the Interchange Agreement.

In-service dates can be inferred from the capital roll forward reports in the Revenue Analysis Workpapers volume, Tab P3, Roll Forward Reports. The roll forward reports have Closings to Plant for each project group and each month which indicate amounts placed in service in that month.

---

**Witness:** Stephen R. Foss  
**Preparer:** Carolyn Brouillard/Shari Cardille  
**Title:** Regulatory Policy Specialist/Principal Rate Analyst  
**Department:** NSPM Regulatory/Revenue Analysis North  
**Telephone:** 612-330-5571/612-330-1974  
**Date:** May 21, 2013

## **Bemidji Update**

**The purpose of the Bemidji Update adjustments is to recognize in the test year forecast changes for the Bemidji CapX2020 projects after the original capital budgets used for the rate case were prepared.**

**Xcel Energy**  
**Annual Revenue Requirement**  
**Transmission - CapX 2020 Bemidji**  
**2013 Test Year North Dakota Electric Rate Case**  
**\$000's**

<u>Rate Analysis</u>	<u>Total Company</u>	<u>ND Jurisdiction</u>
Plant Investment	32,635	1,966
Depreciation Reserve	672	41
CWIP (Excluded for ND Ratemaking)	(34,840)	-
Accumulated Deferred Taxes	11,588	698
	<u>(14,465)</u>	<u>1,228</u>
 Average Rate Base	 (14,465)	 1,228
 Debt Return	 (409)	 35
Equity Return	(791)	67
Current Income Tax Requirement	129	(6)
 Book Depreciation	 662	 40
Annual Deferred Tax	412	25
ITC Flow Thru	-	-
Tax Depreciation & Removal Expense	721	43
AFUDC Expenditure (Excluded for ND Ratemaking)	(2,270)	-
Avoided Tax Interest	(1,624)	(98)
Property Taxes	421	25
<b>Total Revenue Requirements</b>	<b>2,694</b>	<b>186</b>

<u>Capital Structure</u>	<u>Rate</u>	<u>Ratio</u>	<u>Weighted Cost</u>
Long Term Debt	6.0700%	46.3000%	2.8100%
Short Term Debt	2.0600%	1.1400%	0.0200%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	10.4000%	52.5600%	5.4700%
Required Rate of Return			<u>8.3000%</u>
 Tax Rate (ND)	 38.3500%		
ND Jur Demand after IA		6.0227%	

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- Public Document

Xcel Energy

Case No.: PU-12-813

Response To: North Dakota Public  
Service Commission

Data Request No. NDPSC-5-057

Requestor: Snavelly King

Date Received: March 29, 2013

Question:

Witness: Anne E. Heuer-Revenue Requirement (Exhibit AEH-1)

Please refer to page 48 of the Heuer Testimony, Brookings CAPX2020 Transmission Project. Please provide the in- service date and the final costs incurred for each piece of this project completed and the final estimated cost for each piece not completed.

Response:

The following table provides the forecast in-service dates and total Company final costs incurred for each of the three pieces of this project.

CapX 2020 - Brookings			
	Currently In-Service	Forecast Final In-Service Date	Forecast Final Costs
Land & ROW	\$ 1,639,548	June, 2015	\$ 51,946,126
Lines	\$ -	November, 2015	\$ 374,155.907
Subs	\$ -	December, 2015	\$ 76,503,452

Witness: Anne E. Heuer

Preparer: Emily B. Smith

Title: Sr. Rate Analyst

Department: Revenue Requirements North

Telephone: 612.330.6220

Date: May 10, 2013

## **Nuclear Fuel**

**The purpose of the Nuclear Fuel adjustment is to update the capital budget information in the rate case test year for updated nuclear fuel forecast information.**

**Nuclear Fuel Rainbow Update**

	Period	<b>Mn Co Electric</b>												<b>Jur Electric</b>				
		Production				Transmission				Distribution				MN	ND	SD	Whls	
		MN	ND	SD	Whls	MN	ND	SD	Whls	MN	ND	SD	Whls					
<b>Rate Base</b>																		
Plant Investment	BOY	(1,468)	(1,468)	(1,468)	(1,468)												(88)	
Plant Investment	EOY	9,520	9,520	9,520	9,520												573	
Depreciation Reserve	BOY	(227)	(227)	(227)	(227)												(14)	
Depreciation Reserve	EOY	1,061	1,061	1,061	1,061												64	
C.W.I.P.	BOY	(1,871)	0	(1,871)	(1,871)												0	
C.W.I.P.	EOY	(14,889)	0	(14,889)	(14,889)												0	
Accumulated Deferred Taxes	BOY	(298)	(298)	(298)	(298)												(18)	
Accumulated Deferred Taxes	EOY	(80)	(80)	(80)	(80)												(5)	

**Statement of Income**

Operating Expenses:																		
Fuel & Purchased Energy	Annual																	
Power Production	Annual																	
Transmission	Annual																	
Distribution	Annual																	
Customer Accounting	Annual																	
Customer Service & Information	Annual																	
Sales, Econ Dvlp & Other	Annual																	
Administrative & General	Annual																	
<b>Total Operating Expenses:</b>	Annual	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Depreciation	Annual																	
Amortization	Annual																	

Taxes:																		
Property	Annual																	
Gross Earnings Tax	Annual																	
Deferred Income Tax & ITC	Annual	218	218	218	218												13	
Payroll & other	Annual																	
<b>Total Taxes:</b>	Annual	218	218	218	218	0	0	0	0	0	0	0	0	0	0	0	13	0

AFUDC	Annual	(481)	0	(481)	(481)												0	
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**Juris Income Tax**

Tax Deductions:																		
Tax Depreciation & Removal	Annual	1,953	1,953	1,953	1,953												118	
Manufacture Production Deduction	Annual																	
Other Tax/Book Timing Differences	Annual																	
<b>Total Tax Deductions</b>	Annual	1,953	1,953	1,953	1,953	0	0	0	0	0	0	0	0	0	0	0	118	0

**Jurisdiction Cash Working Capital**

Revenue Requirement Exhibits  
 Case No. PUC-12-813  
 Page 95 of 233

Xcel Energy Company  
Electric Utility  
2013 BUDGET

<b>ELECTRIC REVENUES</b>		<b>TOTAL COMPANY</b>	<b>MINNESOTA</b>	<b>NORTH DAKOTA</b>	<b>SOUTH DAKOTA</b>	<b>WHOLESALE</b>
<b>Retail Revenues</b>						
1	Retail	3,131,396,387	2,773,902,719	182,724,120	174,769,547	
2	Rider Adjustment	(81,424,059)	(81,424,059)			
3	Interdepartmental	<u>540,234</u>	<u>540,234</u>	0	0	
4	Total Retail	3,050,512,561	2,693,018,893	182,724,120	174,769,547	0
<b>Other Operating</b>						
6	Late Payment	4,683,713	4,127,482	277,901	278,329	0
7	Connect Charges	2,235,102	1,727,690	273,872	233,540	0
8	CIP Incentive	(21,335,958)	(21,335,958)	0	0	0
9	Rentals	4,207,658	3,683,712	267,863	255,987	96
10	Interchange Production - Capacity	197,529,713	173,661,013	11,896,622	11,855,141	116,938
11	Interchange Production - Energy	200,782,554	175,714,451	13,088,814	11,869,261	110,029
12	Interchange Transmission	43,648,406	38,374,107	2,628,813	2,619,646	25,840
13	Interchange Ag - Decomm	1,090,083	958,362	65,652	65,424	645
14	Sales for Resale- Whls Billed Mrkt	1,374,223	0	0	0	1,374,223
15	Sales for Resale- Non Asset Based	108,000,000	94,515,984	7,040,412	6,384,420	59,184
16	Sales for Resale- Asset Based	44,696,710	39,116,236	2,913,734	2,642,246	24,494
17	Energy Balancing	0	0	0	0	0
18	Cust Charge/Options	0	0	0	0	0
19	Production Associated Revenues	6,458,652	5,652,276	421,033	381,803	3,539
20	Firm Point to Point	9,995,672	8,787,835	602,009	599,910	5,917
21	Network Transmission	28,522,530	25,075,981	1,717,826	1,711,837	16,885
22	Services & Facilities	8,783,100	7,734,077	522,853	521,030	5,139
23	Transmission & Ancillary	117,067,055	102,921,140	7,050,597	7,026,013	69,304
24	MISO Balance Authority	1,658,999	1,458,532	99,917	99,568	982
25	Distribution Associated Revenues	1,092,009	1,092,009	0	0	0
26	Other	9,158,093	8,820,119	181,750	155,226	999
27	Joa - Rev fr PSC	(5,676,000)	(4,967,340)	(370,013)	(335,537)	(3,110)
28	Total Other Operating	763,972,313	667,117,708	48,679,656	46,363,845	1,811,104
30	Total Operating Revenues	3,814,484,874	3,360,136,601	231,403,776	221,133,392	1,811,104
<b>Data Corrections</b>						
	Interchange Decommissioning - WI	(1,090,083)	(958,362)	(65,652)	(65,424)	(645)
	Connect Smart	245,828	245,828	0	0	0
	Monitor NSP	124,549	124,549	0	0	0
	Power Solutions	0	0	0	0	0
	Hedging	0	0	0	0	0
		0	0			
		3,813,765,167	3,359,548,616	231,338,124	221,067,968	1,810,459
<b>Excludes</b>						
	CIP Incentive	21,545,922	21,335,958	0	209,964	0
	SO2 Adjustment	(131,116)	0	(86,733)	(44,383)	0
	Service Quality Adjustment	0	0	0	0	0
	Windsorce Adjustment	0	0	0	0	0
	Non Asset Based Adj	(4,911,960)	(4,484,258)	(334,028)	(90,872)	(2,808)
	Spin Adj for Shareholders	0	0	0	0	0
	Asset Based Adj	(7,289,209)	(6,783,884)	(505,325)	0	0
	MISO Rev Adjustment	(2,187,993)	0	(2,187,993)	0	0
	Champion Distribution	0	0	0	0	0
	Champion Transmission	0	0	0	0	0
	TCR Rider	0	0			
	Adjustment Totals	7,025,638	10,067,816	(3,114,079)	74,709	(2,808)
	Total Operating Revenues	3,820,790,806	3,369,616,432	228,224,045	221,142,677	1,807,651

Xcel Energy Company  
Electric Utility  
2013 Budget

<b>ELECTRIC REVENUES</b>		<b>TOTAL COMPANY</b>	<b>MINNESOTA</b>	<b>NORTH DAKOTA</b>	<b>SOUTH DAKOTA</b>	<b>WHOLESALE</b>
<b>Retail Revenues</b>						
1	Retail	3,131,396,387	2,773,902,719	182,724,120	174,769,547	
2		0	0			
3	Interdepartmental	540,234	540,234	0	0	
4	Total Retail	3,131,936,621	2,774,442,953	182,724,120	174,769,547	0
<b>Other Operating</b>						
6	Late Payment	4,683,713	4,127,482	277,901	278,329	0
7	Connect Charges	2,235,102	1,727,690	273,872	233,540	0
8	CIP Incentive	(21,335,958)	(21,335,958)	0	0	0
9	Rentals	4,207,658	3,683,712	267,863	255,987	96
10	Interchange Production - Capacity	197,529,713	173,661,013	11,896,622	11,855,141	116,938
11	Interchange Production - Energy	200,782,554	175,714,451	13,088,814	11,869,261	110,029
12	Interchange Transmission	43,648,406	38,374,107	2,628,813	2,619,646	25,840
13	Interchange Ag - Decomm	1,090,083	958,362	65,652	65,424	645
14	Sales for Resale- Whls Billed Mrkt	1,374,223	0	0	0	1,374,223
15	Sales for Resale- Non Asset Based	108,000,000	94,515,984	7,040,412	6,384,420	59,184
16	Sales for Resale- Asset Based	44,696,710	39,116,236	2,913,734	2,642,246	24,494
17	Energy Balancing	0	0	0	0	0
18	Cust Charge/Options	0	0	0	0	0
19	Production Associated Revenues	6,458,652	5,652,276	421,033	381,803	3,539
20	Firm Point to Point	9,995,672	8,787,835	602,009	599,910	5,917
21	Network Transmission	28,522,530	25,075,981	1,717,826	1,711,837	16,885
22	Services & Facilities	8,783,100	7,734,077	522,853	521,030	5,139
23	Transmission & Ancillary	117,067,055	102,921,140	7,050,597	7,026,013	69,304
24	MISO Balance Authority	1,658,999	1,458,532	99,917	99,568	982
25	Distribution Associated Revenues	1,092,009	1,092,009	0	0	0
26	Other	9,158,093	8,820,119	181,750	155,226	999
27	Joa - Rev fr PSC	(5,676,000)	(4,967,340)	(370,013)	(335,537)	(3,110)
28	Total Other Operating	763,972,313	667,117,708	48,679,656	46,363,845	1,811,104
30	Total Operating Revenues	3,895,908,933	3,441,560,661	231,403,776	221,133,392	1,811,104
<b>Data Corrections</b>						
	Interchange Decommissioning - WI	(1,090,083)	(958,362)	(65,652)	(65,424)	(645)
	Connect Smart	245,828	245,828	0	0	0
	Monitor NSP	124,549	124,549	0	0	0
	Power Solutions	0	0	0	0	0
	Hedging	0	0	0	0	0
	Nuclear Outage	0	0	0	0	0
		3,895,189,227	3,440,972,676	231,338,124	221,067,968	1,810,459
<b>Excludes</b>						
	CIP Incentive	0	0	0	0	0
	Late Payment -Interest Income Adj	0	0	0	0	0
	Spin Adj for Shareholders	0	0	0	0	0
	nonAsset Adj for Shareholders	0	0	0	0	0
	Champion Distribution	0	0	0	0	0
	Champon Transmission	0	0	0	0	0
	Gain/Loss of SO2 Allowance	0	0	0	0	0
	Service Quality Adj	0	0	0	0	0
	Adjustment Totals	0	0	0	0	0
	Total Operating Revenues	3,895,189,227	3,440,972,676	231,338,124	221,067,968	1,810,459

**Xcel Energy  
2013 Budget**

**Retail Revenues - North Dakota**

	SUM	WIN	ANN		SUM	WIN	ANN
<b>Total Revenue - Present</b>				<b>Fuel - Present</b>			
AllRes	23,224	47,288	70,512	AllRes	6,149	15,289	21,438
RES	17,775	31,681	49,457	RES	4,806	9,752	14,557
RSH	5,449	15,606	21,055	RSH	1,344	5,537	6,881
SCI	31,278	55,076	86,354	SCI	9,939	19,995	29,934
LCI	8,444	14,787	23,230	LCI	3,394	6,465	9,859
LTG	480	1,034	1,515	LTG	89	241	330
OPA	419	695	1,114	OPA	120	239	359
Retail	63,845	118,879	<b>182,724</b>	Retail	19,691	42,228	<b>61,919</b>
ID	0	0	0	ID	0	0	0
Ret+ID	63,845	118,879	182,724	Ret+ID	19,691	42,228	61,919

	SUM	WIN	ANN		SUM	WIN	ANN
<b>Base Revenue - Present</b>				<b>Riders - Present</b>			
AllRes	17,075	31,999	49,073	AllRes	0	0	0
RES	12,970	21,930	34,900	RES	0	0	0
RSH	4,105	10,069	14,174	RSH	0	0	0
SCI	21,339	35,081	56,420	SCI	0	0	0
LCI	5,050	8,321	13,371	LCI	0	0	0
LTG	391	794	1,185	LTG	0	0	0
OPA	299	456	755	OPA	0	0	0
Retail	44,154	76,651	<b>120,805</b>	Retail	0	0	<b>0</b>
ID	0	0	0	ID	0	0	0
Ret+ID	44,154	76,651	120,805	Ret+ID	0	0	0

	SUM	WIN	ANN
<b>GWH Sales</b>			
AllRes	226,114	558,979	785,093
RES	176,710	356,548	533,258
RSH	49,404	202,430	251,835
SCI	361,784	727,520	1,089,305
LCI	126,296	240,811	367,107
LTG	4,391	11,888	16,279
OPA	4,326	8,612	12,938
Retail	722,911	1,547,810	<b>2,270,721</b>
ID	0	0	0
Ret+ID			2,270,721

- Residential Total
- Residential Regular
- Residential Space Heating
- Small C&I
- Large C&I
- Street Lighting
- Other Sales to Public Authorities
- Retail
- Interdepartmental

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Xcel Energy

Case No.: PU-12-813

Response To: North Dakota Public Service Commission      Data Request No.      NDPSC-5-039

Requestor: Snavelly King

Date Received: March 29, 2013

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Question:

Witness: Anne E. Heuer-Revenue Requirement (Exhibit AEH-1)

Please refer to page 27 of the Heuer Testimony, Net Sales and Growth in Margin, in the amount of \$(1.8 million). (Exhibit AEH-1, Schedule 9, page 1 of 2). Please provide a breakdown of the additional customers added to the system, and the corresponding usage associated with each customer. Provide the same information for the years 2011 and 2012.

Response:

Attachment A to this response provides the net change by class in customer counts and weather normalized use per customer for 2010, 2011, 2012, and 2013.

---

Preparer: Jannell E. Marks  
Title: Director  
Department: Load Forecasting and Analysis  
Telephone: 303-571-6254  
Date: April 29, 2013

**PUBLIC DOCUMENT:  
TRADE SECRET INFORMATION EXCISED**

- Non Public Document – Contains Trade Secret Data  
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 Public Document

Xcel Energy

Case No.: PU-12-813

Response To: North Dakota Public Service Commission      Data Request No.      NDPSC-5-071

Requestor: Snavelly King

Date Received: March 29, 2013

Question:

Witness: Laura McCarten-Policy Testimony (Exhibit LM-1)

Please refer to page 5 of the McCarten Testimony, Figure 1, Sales Growth and Margins. What type of Sales Growth has the Company experienced in 2013? Please provide by class of customer, location and usage.

Response:

The table below compares North Dakota weather normalized retail sales by class for the first quarter 2013 with sales for the first quarter 2012.

**North Dakota Sales by Class (MWh)**

	Q1 2012	Q1 2013	% Change
Residential w/o Space Heating	139,449	148,355	6.4%
Residential with Space Heating	101,644	100,812	-0.8%
Small Commercial & Industrial	273,930	281,572	2.8%
Large Commercial & Industrial	83,036	76,362	-8.0%
Street Lighting	4,651	4,724	1.6%
Other	3,328	3,549	6.7%
<b>Total Retail</b>	<b>606,038</b>	<b>615,374</b>	<b>1.5%</b>

The Company does not convert billed usage into calendar month usage at any level other than the state of North Dakota. Nor does it calculate weather-normalized sales at any level other than the state of North Dakota. However, the actual billed usage by class of customer and location is provided as Attachment A. The year-over-year variations presented in Attachment A are influenced by differences in both weather and billing schedules.

Please note that portions of Attachment A are marked "Non-Public" as it contains information described in the Company's Trade Secret Application in this Case.

---

Witness: Anne E. Heuer  
Preparer: Jannell Marks  
Title: Director  
Department: Load Forecasting and Analysis  
Telephone: 303-571-6254  
Date: April 18, 2013

**PUBLIC DOCUMENT:  
TRADE SECRET INFORMATION EXCISED**

Case No. PU-12-813  
Data Request No. NDPSC-5-071  
Attachment A  
Page 1 of 4

Residential kWh Sales	Jan-12	Feb-12	Mar-12	Q1 2012	Jan-13	Feb-13	Mar-13	Q1 2013	% Change
AMERICUS (TWP)	20,285	17,360	20,540	58,185	32,754	9,610	17,531	59,895	2.9%
ARVILLA (TWP)	5,509	4,716	4,213	14,438	6,208	5,142	5,076	16,426	13.8%
BARNES (TWP)	3,483	3,229	2,497	9,209	1,323	1,217	1,293	3,833	-58.4%
BERTHOLD (CITY)	274,043	268,730	212,827	755,600	615,825	17,917	295,981	929,723	23.0%
BERTHOLD (TWP)	4,740	4,932	3,726	13,398	9,095	0	4,235	13,330	-0.5%
BURLINGTON (CITY)	671,231	588,139	551,482	1,810,852	577,972	514,220	480,374	1,572,566	-13.2%
BURLINGTON (TWP)	33,207	43,992	44,312	121,511	47,490	42,414	37,370	127,274	4.7%
BUXTON (CITY)	376,085	328,873	514,697	1,219,655	748,596	24,192	345,339	1,118,127	-8.3%
BUXTON (TWP)	4,584	4,219	4,438	13,241	0	0	0	0	-100.0%
CUMMINGS (TOWN)	37,741	31,510	47,544	116,795	67,605	2,990	32,256	102,851	-11.9%
DES LACS (CITY)	103,948	85,808	80,870	270,626	117,471	102,051	97,710	317,232	17.2%
DES LACS (TWP)	17,052	14,527	13,272	44,851	18,252	16,985	15,199	50,436	12.5%
ERVIN (TWP)	13,972	11,439	19,489	44,900	28,820	0	13,399	42,219	-6.0%
FALCONER (TWP)	7,625	7,348	6,074	21,047	0	0	0	0	-100.0%
FARGO (CITY)	35,614,795	33,315,196	30,722,862	99,652,853	43,254,299	36,251,927	32,801,270	112,307,496	12.7%
FOXHOLM (TWP)	16,976	14,249	10,299	41,524	25,162	3,214	13,507	41,883	0.9%
GARFIELD (TWP)	7,414	6,374	5,595	19,383	8,168	6,694	4,787	19,649	1.4%
GASMAN (TWP)									-6.8%
GRAND FORKS (CITY)	22,139,030	20,267,821	17,372,900	59,779,751	25,577,488	22,583,166	17,951,249	66,111,903	10.6%
GRAND FORKS (TWP)	13,466	12,947	10,860	37,273	17,636	16,400	14,600	48,636	30.5%
HARRISON (TWP)	522,953	514,944	473,200	1,511,097	557,973	466,515	412,184	1,436,672	-4.9%
HATTON (CITY)	565,261	533,011	429,246	1,527,518	765,560	582,478	548,707	1,896,745	24.2%
KIRKELIE (TWP)	105,495	111,440	99,093	316,028	141,673	121,341	110,592	373,606	18.2%
LARIMORE (CITY)	1,107,179	1,124,449	937,187	3,168,815	1,399,598	1,281,451	1,090,771	3,771,820	19.0%
LARIMORE (TWP)	23,743	23,048	19,462	66,253	29,554	26,897	23,264	79,715	20.3%
MAYVILLE (CITY)	1,625,390	1,582,232	1,414,461	4,622,083	1,994,569	1,899,107	1,563,524	5,457,200	18.1%
MAYVILLE (TWP)	7,641	6,950	7,037	21,628	10,085	8,607	8,533	27,225	25.9%
MINOT (CITY)	13,620,266	12,108,068	11,425,235	37,153,569	16,369,961	13,895,811	12,901,154	43,166,926	16.2%
NEDROSE (TWP)	60,110	52,186	48,426	160,722	87,721	72,111	68,985	228,817	42.4%
PORTLAND (CITY)	668,409	616,534	487,260	1,772,203	818,841	712,074	527,384	2,058,299	16.1%
REED (TWP)	24,767	20,494	17,503	62,764	23,490	15,801	19,018	58,309	-7.1%
REYNOLDS (CITY)	354,059	268,878	454,706	1,077,643	684,493	29,510	330,760	1,044,763	-3.1%
STAVANGER (TWP)	8,694	7,385	15,489	31,568	14,722	5,153	12,494	32,369	2.5%
THOMPSON (CITY)	801,169	696,325	1,136,492	2,633,986	1,574,499	98,772	748,209	2,421,480	-8.1%
UNINCORPORATED ND	1,775	1,524	1,480	4,779	1,590	1,540	1,496	4,626	-3.2%
VIKING (TWP)	26,472	20,919	21,591	68,982	29,538	24,924	20,214	74,676	8.3%
WALLE (TWP)	37,824	35,084	51,564	124,472	79,433	9,826	39,232	128,491	3.2%
WEST FARGO (CITY)	5,879,104	4,860,255	4,116,654	14,856,013	6,784,318	5,790,147	5,161,052	17,735,517	19.4%
<b>Total</b>									<b>12.7%</b>

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Comm/Ind kWh Sales	Jan-12	Feb-12	Mar-12	Q1 2012	Jan-13	Feb-13	Mar-13	Q1 2013	% Change
ALLEDALE (TWP)									-8.0%
AMERICUS (TWP)									635.7%
ARVILLA (TWP)									-59.6%
BARNES (TWP)	2	1	10	13	116,282	55,204	82,930	254,416	1956946.2%
BERTHOLD (CITY)	117,805	102,711	96,771	317,287	174,105	96,586	135,179	405,870	27.9%
BERTHOLD (TWP)	26	26	22	74	0	0	0	0	-100.0%
BURLINGTON (CITY)	272,763	258,146	247,613	778,522	264,948	238,033	180,610	683,591	-12.2%
BURLINGTON (TWP)	54,576	51,736	49,440	155,752	60,160	55,009	63,616	178,785	14.8%
BUXTON (CITY)	190,728	202,642	196,812	590,182	234,362	184,134	215,824	634,320	7.5%
BUXTON (TWP)	15,106	15,962	15,586	46,654	32,885	16,718	17,965	67,568	44.8%
CUMMINGS (TOWN)	63,086	41,630	37,493	142,209	60,967	45,790	44,637	151,394	6.5%
DES LACS (CITY)	53,147	49,509	48,034	150,690	55,866	49,846	49,361	155,073	2.9%
DES LACS (TWP)									-100.0%
ERVIN (TWP)									46.2%
FALCONER (TWP)	11,808	15,139	10,771	37,718	16,476	15,278	13,350	45,104	19.6%
FARGO (CITY)	64,967,013	61,901,058	61,122,293	187,990,364	67,070,999	58,222,971	61,852,141	187,146,111	-0.4%
FOXHOLM (TWP)	1,140	1,113	770	3,023	2,684	9	1,354	4,047	33.9%
GARFIELD (TWP)	32,240	21,649	19,438	73,327	43,777	40,439	28,035	112,251	53.1%
GRAND FORKS (CITY)	31,158,051	26,771,236	30,948,739	88,878,026	32,085,186	29,355,164	30,487,559	91,927,909	3.4%
GRAND FORKS (TWP)	2,057	5,429	2,625	10,111	3,887	3,649	3,187	10,723	6.1%
HARRISON (TWP)	674,196	541,815	555,916	1,771,927	651,066	598,675	544,783	1,794,524	1.3%
HATTON (CITY)	354,908	306,197	365,057	1,026,162	376,029	332,351	313,242	1,021,622	-0.4%
KIRKELIE (TWP)	6,411	-2,592	4,448	8,267	3,084	2,518	2,334	7,936	-4.0%
LARIMORE (CITY)	477,053	478,493	430,090	1,385,636	558,222	530,725	454,233	1,543,180	11.4%
LARIMORE (TWP)	99,152	110,263	93,945	303,360	181,197	136,547	126,679	444,423	46.5%
LINDAAS (TWP)	212	177	157	546	217	173	155	545	-0.2%
MAYVILLE (CITY)	1,859,022	1,747,600	1,732,471	5,339,093	2,055,047	2,008,130	1,887,447	5,950,624	11.5%
MAYVILLE (TWP)	40,138	37,206	41,935	119,279	29,196	29,294	24,540	83,030	-30.4%
MINOT (CITY)	16,204,930	13,924,783	15,470,381	45,600,094	17,708,184	14,262,147	15,074,168	47,044,499	3.2%
NEDROSE (TWP)	2,818,926	2,829,976	2,350,753	7,999,655	1,214,472	1,077,507	1,153,575	3,445,554	-56.9%
PORTLAND (CITY)	197,852	164,870	144,607	507,329	190,816	169,882	140,674	501,372	-1.2%
REED (TWP)	8,566	7,796	5,736	22,098	29,865	28,925	26,895	85,685	287.8%
REYNOLDS (CITY)	143,390	108,131	107,637	359,158	157,322	106,004	122,951	386,277	7.6%
STANLEY (TWP)	10,238	9,402	8,980	28,620	10,484	8,602	8,919	28,005	-2.1%
STAVANGER (TWP)	18,113	681,458	268,304	967,875	1,107,430	771,215	160,838	2,039,483	110.7%
SUNDRE (TWP)									-100.0%
THOMPSON (CITY)	249,436	197,454	199,942	646,832	258,407	214,775	183,478	656,660	1.5%
UNINCORPORATED ND	4,736	5,084	5,026	14,846	6,786	5,465	4,605	16,856	13.5%
WALLE (TWP)	9,194	4,128	5,843	19,165	9,098	5,172	9,899	24,169	26.1%
WEST FARGO (CITY)	8,527,821	7,950,005	7,843,382	24,321,208	8,580,900	6,821,377	7,820,874	23,223,151	-4.5%
<b>Total</b>	<b>128,701,295</b>	<b>118,596,492</b>	<b>122,478,908</b>	<b>369,776,695</b>	<b>133,409,692</b>	<b>115,536,001</b>	<b>121,285,243</b>	<b>370,230,936</b>	<b>0.1%</b>

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TRADE SECRET INFORMATION EXCISED**

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St. Lght. kWh Sales	Jan-12	Feb-12	Mar-12	Q1 2012	Jan-13	Feb-13	Mar-13	Q1 2013	% Change
BERTHOLD (CITY)	5,718	5,484	4,593	15,795	5,718	5,495	4,581	15,794	0.0%
BURLINGTON (CITY)	5,356	4,371	4,149	13,876	5,059	4,684	3,982	13,725	-1.1%
BURLINGTON (TWP)									0.3%
BUXTON (CITY)									0.0%
DES LACS (CITY)									-1.2%
FARGO (CITY)	838,026	802,378	679,621	2,320,025	882,398	823,808	696,011	2,402,217	3.5%
GRAND FORKS (CITY)	337,334	313,848	268,351	919,533	319,226	305,781	270,400	895,407	-2.6%
HARRISON (TWP)	14,417	13,763	11,544	39,724	14,351	13,742	11,490	39,583	-0.4%
HATTON (CITY)									0.0%
LARIMORE (CITY)	8,922	8,557	7,166	24,645	8,922	8,574	7,147	24,643	0.0%
MAYVILLE (CITY)	12,131	11,635	9,742	33,508	12,131	11,659	9,719	33,509	0.0%
MINOT (CITY)	393,167	381,130	321,833	1,096,130	396,039	379,893	316,536	1,092,468	-0.3%
NEDROSE (TWP)	6,861	6,580	5,510	18,951	6,861	6,594	5,496	18,951	0.0%
PORTLAND (CITY)	6,899	6,617	5,541	19,057	6,953	6,682	5,571	19,206	0.8%
REYNOLDS (CITY)	3,384	3,149	2,651	9,184	3,384	3,200	2,600	9,184	0.0%
THOMPSON (CITY)									3.0%
WALLE (TWP)									-10.7%
WEST FARGO (CITY)	97,851	93,901	78,558	270,310	111,698	102,731	77,897	292,326	8.1%
<b>Total</b>	<b>1,758,624</b>	<b>1,676,650</b>	<b>1,422,947</b>	<b>4,858,221</b>	<b>1,803,803</b>	<b>1,696,118</b>	<b>1,434,499</b>	<b>4,934,420</b>	<b>1.6%</b>

**PUBLIC DOCUMENT:  
TRADE SECRET INFORMATION EXCISED**

Case No. PU-12-813  
Data Request No. NDPSC-5-071  
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Other Pub Auth kWh Sales	Jan-12	Feb-12	Mar-12	Q1 2012	Jan-13	Feb-13	Mar-13	Q1 2013	% Change
BERTHOLD (CITY)	462	509	379	1,350	837	743	368	1,948	44.3%
BURLINGTON (CITY)	4,857	3,930	4,490	13,277	5,819	5,884	4,794	16,497	24.3%
BURLINGTON (TWP)	199	249	228	676	348	350	227	925	36.8%
BUXTON (CITY)	350	296	258	904	348	297	284	929	2.8%
DES LACS (CITY)	206	169	197	572	178	162	115	455	-20.5%
FARGO (CITY)	228,100	207,778	201,142	637,020	231,546	247,347	217,183	696,076	9.3%
GRAND FORKS (CITY)	326,533	310,199	233,870	870,602	350,196	375,751	337,722	1,063,669	22.2%
HARRISON (TWP)									41.1%
HATTON (CITY)	4,183	3,310	3,242	10,735	4,253	3,405	3,144	10,802	0.6%
LARIMORE (CITY)	3,726	3,535	3,387	10,648	4,797	4,267	4,892	13,956	31.1%
MAYVILLE (CITY)	9,493	8,823	9,412	27,728	14,278	12,652	13,174	40,104	44.6%
MINOT (CITY)	567,414	552,466	447,022	1,566,902	470,331	722,749	444,224	1,637,304	4.5%
PORTLAND (CITY)	8,588	8,512	7,241	24,341	10,019	8,986	7,411	26,416	8.5%
REYNOLDS (CITY)									2.8%
SUNDRE (TWP)	580	25,000	22,551	48,131	36,761	28,492	25,317	90,570	88.2%
THOMPSON (CITY)	2,078	1,936	1,570	5,584	1,876	1,661	1,682	5,219	-6.5%
WEST FARGO (CITY)	42,063	35,516	33,495	111,074	112,765	13,586	52,412	178,763	60.9%
<b>Total</b>	<b>1,199,452</b>	<b>1,163,471</b>	<b>969,769</b>	<b>3,332,692</b>	<b>1,245,304</b>	<b>1,428,428</b>	<b>1,114,163</b>	<b>3,787,895</b>	<b>13.7%</b>

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Northern States Power Company  
Electric Utility - State of North Dakota

Case No. PU-12-813  
NDPSC Data Request 5-039  
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**North Dakota Customer Counts and Use per Customer**

	Year-End Customer Counts				Annual Change		
	2010	2011	2012	2013 TY	2011	2012	2013 TY
Residential without Space Heating	56,472	55,144	56,565	57,638	-1,328	1,421	1,073
Residential with Space Heating	19,847	20,982	20,666	20,409	1,135	-316	-257
Small Commercial & Industrial	12,078	12,033	12,182	12,319	-45	149	137
Large Commercial & Industrial	20	20	21	21	0	1	0
Street Lighting	96	100	127	129	4	27	2
Other	188	180	186	187	-8	6	1
<b>Total Retail</b>	<b>88,701</b>	<b>88,459</b>	<b>89,747</b>	<b>90,703</b>	<b>-242</b>	<b>1,288</b>	<b>956</b>

	Use per Customer (kWh) (Weather Normalized)				Annual Change		
	2010	2011	2012	2013 TY	2011	2012	2013 TY
Residential without Space Heating	9,194	9,279	9,202	9,340	85	-77	138
Residential with Space Heating	12,774	12,696	12,546	12,377	-78	-150	-169
Small Commercial & Industrial	88,098	90,227	89,133	88,910	2,129	-1,093	-224
Large Commercial & Industrial	17,705,231	17,538,213	16,958,562	17,481,288	-167,018	-579,651	522,726
Street Lighting	171,560	162,366	135,965	127,083	-9,194	-26,401	-8,882
Other	70,459	75,470	72,575	69,123	5,010	-2,895	-3,452

- Non Public Document – Contains Trade Secret Data  
 Public Document – Trade Secret Data Excised  
 Public Document

Xcel Energy

Case No.: PU-12-813  
Response To: North Dakota Public Service Commission      Data Request No.      NDPSC-5-027  
Requestor: Snavelly King  
Date Received: March 29, 2013

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Question:

Witness: Anne E. Heuer-Revenue Requirement (Exhibit AEH-1)

Please refer to Exhibit (AEH-1), Schedule 6, page 1 and 3, please provide a breakdown of Other Operating Revenues of \$48.616 million (Column 1) and \$45.502 million (Proposed 2013 Test Year). Please refer to Exhibit (AEH-1), Schedule 3, page 3 of 6; provide a breakdown of Other Operating Revenues in the amount of \$37.594 million (ND Retail Electric).

Response:

The Other Operating Revenue of \$48.616 million (Column 1) and \$45.502 million (Proposed 2013 Test Year) found in Schedule 6 is broken out in detail in NDPSC-5-027 Attachment A, page 1 of 2. The Other Operating Revenue of \$37.594 from Schedule 3, page 3 of 6 is also provided in greater detail in Attachment A, page 2 of 2. Please note, the minor differences between values in testimony and Attachment A are due to rounding and not materially significant.

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Witness: Anne E. Heuer  
Preparer: Jeff Hafner  
Title: Senior Rate Analyst  
Department: Revenue Requirements – North  
Telephone: 612 330-7622  
Date: April 11, 2013

Northern States Power Company  
Electric Utility - State of North Dakota  
2013 BUDGET

Case No. PU-12-813  
NDPSC-DR-5-027  
Attachment A  
Page 1 of 2

ELECTRIC REVENUES

	TOTAL COMPANY	MINNESOTA	NORTH DAKOTA	SOUTH DAKOTA	WHOLESALE	
<b>Retail Revenues</b>						
1	Retail	3,131,396,387	2,773,902,719	182,724,120	174,769,547	
2	Rider Adjustment	(81,424,059)	(81,424,059)			
3	Interdepartmental	540,234	540,234	0	0	
4	Total Retail	3,050,512,561	2,693,018,893	182,724,120	174,769,547	0
<b>Other Operating</b>						
6	Late Payment	4,683,713	4,127,482	277,901	278,329	0
7	Connect Charges	2,235,102	1,727,690	273,872	233,540	0
8	CIP Incentive	(21,335,958)	(21,335,958)	0	0	0
9	Rentals	4,207,658	3,683,712	267,863	255,987	96
10	Interchange Production - Capacity	197,529,713	173,661,013	11,896,622	11,855,141	116,938
11	Interchange Production - Energy	200,782,554	175,714,451	13,088,814	11,869,261	110,029
12	Interchange Transmission	43,648,406	38,374,107	2,628,813	2,619,646	25,840
13	Interchange Ag - Decomm	1,090,083	958,362	65,652	65,424	645
14	Sales for Resale- Whls Billed Mkt	1,374,223	0	0	0	1,374,223
15	Sales for Resale- Non Asset Based	108,000,000	94,515,984	7,040,412	6,384,420	59,184
16	Sales for Resale- Asset Based	44,696,710	39,116,236	2,913,734	2,642,246	24,494
17	Energy Balancing	0	0	0	0	0
18	Cust Charge/Options	0	0	0	0	0
19	Production Associated Revenues	6,458,652	5,652,276	421,033	381,803	3,539
20	Firm Point to Point	9,995,672	8,787,835	602,009	599,910	5,917
21	Network Transmission	28,522,530	25,075,981	1,717,826	1,711,837	16,885
22	Services & Facilities	8,783,100	7,734,077	522,853	521,030	5,139
23	Transmission & Ancillary	117,067,055	102,921,140	7,050,597	7,026,013	69,304
24	MISO Balance Authority	1,658,999	1,458,532	99,917	99,568	982
25	Distribution Associated Revenues	1,092,009	1,092,009	0	0	0
26	Other	9,158,093	8,820,119	181,750	155,226	999
27	Joa - Rev fr PSC	(5,676,000)	(4,967,340)	(370,013)	(335,537)	(3,110)
28	Total Other Operating	763,972,313	667,117,708	48,679,656	46,363,845	1,811,104
30	Total Operating Revenues	3,814,484,874	3,360,136,601	231,403,776	221,133,392	1,811,104
<b>Data Corrections</b>						
	Interchange Decommissioning - WI	(1,090,083)	(958,362)	(65,652)	(65,424)	(645)
	Connect Smart	245,828	245,828	0	0	0
	Monitor NSP	124,549	124,549	0	0	0
	Power Solutions	0	0	0	0	0
	Hedging	0	0	0	0	0
		0	0			
		3,813,765,167	3,359,548,616	231,338,124	221,067,968	1,810,459
<b>Excludes</b>						
	CIP Incentive	21,545,922	21,335,958	0	209,964	0
	SO2 Adjustment	(131,116)	0	(86,733)	(44,383)	0
	Service Quality Adjustment	0	0	0	0	0
	Windsorce Adjustment	0	0	0	0	0
	Non Asset Based Adj	(4,911,966)	(4,484,258)	(334,026)	(90,872)	(2,808)
	Spin Adj for Shareholders	0	0	0	0	0
	Asset Based Adj	(7,289,209)	(6,783,884)	(505,325)	0	0
	MISO Rev Adjustment	(2,187,993)	0	(2,187,993)	0	0
	Champion Distribution	0	0	0	0	0
	Champion Transmission	0	0	0	0	0
	TCR Rider	0	0			
	Adjustment Totals	7,025,638	10,067,816	(3,114,079)	74,709	(2,808)
	Total Operating Revenues	3,820,790,806	3,369,616,432	228,224,045	221,142,677	1,807,651
	Total Other Revenue including Decomm	763,252,606		48,614,003		
	Adjustment totals for North Dakota	7,025,638		(3,114,079)		
	Total Other Revenue after adjustments	770,278,245		45,499,925		

Northern States Power Company  
Electric Utility - State of North Dakota  
2011 ACTUAL

Case No. PU-12-813  
NDPSC-DR-5-027  
Attachment A  
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**ELECTRIC REVENUES**

	<b>TOTAL COMPANY</b>	<b>MINNESOTA</b>	<b>NORTH DAKOTA</b>	<b>SOUTH DAKOTA</b>	<b>WHOLESALE</b>	
<b>Retail Revenues</b>						
1	Retail	3,111,896,328	2,773,746,544	176,289,590	161,860,194	
2	Weather	0	0			
3	Interdepartmental	548,276	548,276	0	0	
4	Total Retail	3,112,444,604	2,774,294,820	176,289,590	161,860,194	0
<b>Other Operating</b>						
5	Prov for Rate Ref Pub Auth/ Cust O	0	0	0	0	0
6	Late Payment	4,932,367	4,344,591	293,958	293,818	0
7	Connect Charges	2,176,467	1,652,840	277,806	245,822	0
8	CIP Incentive	39,317,070	39,317,070	0	0	0
9	Rentals	4,187,102	3,673,418	262,137	251,357	190
10	Interchange Production - Capacity	195,939,717	173,136,449	11,268,689	11,308,073	226,506
11	Interchange Production - Energy	202,288,680	178,036,897	12,582,154	11,437,200	232,430
12	Interchange Transmission	41,200,349	36,405,493	2,369,473	2,377,755	47,628
13	Interchange Ag - Decomm	1,090,415	963,514	62,711	62,930	1,261
14	Sales for Resale- Whls Billed Mrkt	2,443,277	0	0	0	2,443,277
15	Sales for Resale- Non Asset Based	24,105,000	21,215,124	1,499,307	1,362,873	27,697
16	Sales for Resale- Asset Based	44,872,591	39,492,951	2,791,030	2,537,051	51,559
17	Energy Balancing	8,137,210	7,161,664	506,126	460,070	9,350
18	Cust Charge/Options	0	0	0	0	0
19	Production Associated Revenues	5,875,317	5,170,943	365,439	332,185	6,751
20	Firm Point to Point	632,120	558,554	36,354	36,481	731
21	Network Transmission	55,777,023	49,285,749	3,207,792	3,219,004	64,478
22	Services & Facilities	8,658,879	7,651,167	497,981	499,721	10,010
23	Ancillary	23,478,930	20,746,476	1,350,297	1,355,016	27,142
24	MISO	9,445,290	8,346,056	543,208	545,107	10,919
25	Distribution Associated Revenues	678,613	586,137	92,532	(55)	(1)
26	AES Reimbursements	335,231	335,231	0	0	0
27	Other	10,530,446	10,166,883	175,276	185,742	2,546
28	Joa - Rev fr PSC	(4,813,245)	(4,236,199)	(299,379)	(272,136)	(5,530)
29	Total Other Operating	681,288,848	604,011,008	37,882,889	36,238,011	3,156,940
30	Gross Earnings Tax Revenues	0	0	0	0	0
31	Total Operating Revenues	3,793,733,452	3,378,305,828	214,172,480	198,098,204	3,156,940
<b>Data Corrections</b>						
	Interchange Decommissioning - WI	(1,090,415)	(963,514)	(62,711)	(62,930)	(1,261)
	Connect Smart	22,001	22,001	0	0	0
	Monitor NSP	0	0	0	0	0
	Power Solutions	470	470	0	0	0
	Hedging	0	0	0	0	0
		0	0			
		3,792,665,508	3,377,364,785	214,109,769	198,035,274	3,155,680
<b>Excludes</b>						
	CIP Incentive	(39,317,070)	(39,317,070)	0	0	0
	Service Quality Adjustment	382,034	382,034			
	Asset Based Adj	(81,261)	0	(81,261)	0	0
	Spin Adj for Shareholders	0	0	0	0	0
	NonAsset Adj for Shareholders	(4,407,448)	(4,067,727)	(143,736)	(195,985)	
	Champion Distribution	158,531	158,531	0	0	0
	Champion Transmission	84,226	84,226	0	0	0
	Nuclear Outage	(3,440,723)	(3,440,723)			
	Adjustment Totals	(46,621,711)	(46,200,729)	(224,997)	(195,985)	0
	Total Operating Revenues	3,746,043,796	3,331,164,055	213,884,772	197,839,289	3,155,680
	Total Revenue including Decomm	680,220,904		37,820,179		
	Adjustment totals	(46,621,711)		(224,997)		
	Total Revenue after adjustments	633,599,192		37,595,182		

## Purpose

This adjustment removes the MISO revenues and expenses associate with transmission projects currently in Construction Work in Progress (CWIP). Since North Dakota rule making does not allow long term CWIP in rate base. The North Dakota jurisdictional share of the transmission revenue and expenses associated with CWIP transmission projects is being excluded from the test year.

2013 CWIP Related  
MISO Revenues and Expenses  
As Allocated to the North Dakota Retail Jurisdiction

<u>2013 MISO Attachment GG &amp; MM</u>		<u>Revenue</u>	<u>Expense</u>	<u>ND Demand</u>	<u>IA Demand</u>	<u>ND Adj Revenue</u>	<u>ND Adj Expense</u>
GG	Twin Cities - Fargo CWIP	12,745,095	6,465,503	6.0227%	84.8812%	651,547	330,526
GG	Twin Cities - Rochester CWIP	3,326,441	1,592,683.561	6.0227%	84.8812%	170,052	81,420
MM	Brookings 2013 CWIP	<u>26,728,403</u>	<u>2,447,648</u>	6.0227%	84.8812%	<u>1,366,393</u>	<u>125,127</u>
	<b>Totals</b>	<b>42,799,939</b>	<b>10,505,835</b>			<b>2,187,993</b>	<b>537,073</b>
		<u>IA Demand</u>	<u>IA Demand</u>				
		84.8812%	84.8812%				
	<b>Adjustment</b>	<b>(36,329,102)</b>	<b>(8,917,479)</b>			<b>(2,187,993)</b>	<b>(537,073)</b>

**NSP Owned Projects**  
**Forecast MISO Revenue & Expense**  
**Schedule 26 & 26A (2013 MISO Budget - October Update)**  
**Based on 2011 Actual Load-Share in Pricing Zones**

<b>Revenues</b>	<b>MISO Filing</b>					
	<b>2012</b>	<b>2013</b>	<b>2014</b>	<b>2015</b>	<b>2016</b>	<b>2017</b>
Attachment GG (Sched 26)	17,581,473	<b>38,082,828</b>	64,832,318	86,820,260	101,440,993	100,024,188
Attachment MM (Sched 26A)	8,876,452	<b>31,294,493</b>	61,312,263	69,903,780	70,313,276	69,739,312
<b>Total Revenues</b>	<b>26,457,925</b>	<b>69,377,321</b>	126,144,582	156,724,040	171,754,269	169,763,499
<b>Expense</b>						
Attachment GG (Sched 26)	9,570,107	20,314,125	34,565,190	46,758,284	54,680,484	53,906,910
Attachment MM (Sched 26A)	812,859	2,865,787	5,614,658	6,401,425	6,438,924	6,386,363
<b>Total Expense</b>	<b>10,382,966</b>	<b>23,179,912</b>	40,179,848	53,159,709	61,119,408	60,293,274
<b>Net Amount</b>						
Attachment GG (Sched 26)	8,011,366	17,768,703	30,267,128	40,061,976	46,760,509	46,117,277
Attachment MM (Sched 26A)	8,063,593	28,428,706	55,697,605	63,502,355	63,874,352	63,352,948
<b>Total Net</b>	<b>16,074,959</b>	<b>46,197,408</b>	85,964,733	103,564,332	110,634,860	109,470,226

## North Dakota Emission Allowances Amortization

The Company has placed the ND electric proceeds from emission allowance sales into FERC account 254, Other Regulatory Liabilities, pending a determination of the ratemaking treatment of the gains from such transactions.

**2013 ND Electric Rate Case  
ND EPA Emission Credit Auction Proceeds**

**JDE Acct  
10.424490**

	Amortize over 36 Month: Balance 12/31/2010	<u>(260,197.69)</u>
	Balance 12/31/2011	<u>(185,217.29)</u>
Jan 12	7,227.71	(177,989.58)
Feb 12	7,227.71	(170,761.87)
Mar 12	7,227.71	(163,534.16)
Apr 12	7,190.28	(156,343.88)
May 12	7,227.71	(149,116.17)
Jun 12	7,227.71	(141,888.46)
Jul 12	7,227.71	(134,660.75)
Aug 12	7,227.71	(127,433.04)
Sep 12	7,227.71	(120,205.33)
Oct 12	7,227.71	(112,977.62)
Nov 12	7,227.71	(105,749.91)
Dec 12	7,227.71	(98,522.20)
	Balance 12/31/2012	<u>(98,522.20)</u>

For ND Rate Case request amortization over 36 months

Jan 13	2,736.73	(95,785.47)
Feb 13	2,736.73	(93,048.74)
Mar 13	2,736.73	(90,312.02)
Apr 13	2,736.73	(87,575.29)
May 13	2,736.73	(84,838.56)
Jun 13	2,736.73	(82,101.83)
Jul 13	2,736.73	(79,365.11)
Aug 13	2,736.73	(76,628.38)
Sep 13	2,736.73	(73,891.65)
Oct 13	2,736.73	(71,154.92)
Nov 13	2,736.73	(68,418.19)
Dec 13	2,736.73	(65,681.47)
Jan 14	2,736.73	(62,944.74)
Feb 14	2,736.73	(60,208.01)
Mar 14	2,736.73	(57,471.28)
Apr 14	2,736.73	(54,734.56)
May 14	2,736.73	(51,997.83)
Jun 14	2,736.73	(49,261.10)
Jul 14	2,736.73	(46,524.37)
Aug 14	2,736.73	(43,787.64)
Sep 14	2,736.73	(41,050.92)
Oct 14	2,736.73	(38,314.19)
Nov 14	2,736.73	(35,577.46)
Dec 14	2,736.73	(32,840.73)
Jan 15	2,736.73	(30,104.01)
Feb 15	2,736.73	(27,367.28)
Mar 15	2,736.73	(24,630.55)
Apr 15	2,736.73	(21,893.82)
May 15	2,736.73	(19,157.09)
Jun 15	2,736.73	(16,420.37)
Jul 15	2,736.73	(13,683.64)
Aug 15	2,736.73	(10,946.91)
Sep 15	2,736.73	(8,210.18)
Oct 15	2,736.73	(5,473.46)
Nov 15	2,736.73	(2,736.73)
Dec 15	2,736.73	0.00

Amount in CFM revenue that must be removed.  
\$86,733 (\$7,227.71 \* 12)

ND Emission  
(32,840.73)

- Non Public Document – Contains Trade Secret Data  
 Public Document – Trade Secret Data Excised  
 Public Document

Xcel Energy

Docket No.: PU-12-813

Response To: North Dakota Public Service Commission      Data Request No.      NDPSC-1-008

Requestor: Michael Diller & Sara Cardwell

Date Received: February 26, 2013

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Question:

Please see excerpt below from Heuer testimony in MN General Rate Case Docket No. 12-961 regarding asset based margins:

**Q. HOW HAVE ASSET BASED MARGINS BEEN TREATED IN PRIOR RATE CASES?**

A. Because asset based margins are created by selling energy from facilities or PPAs paid for by ratepayers, all asset based margins have been credited to ratepayers. In Docket No. E002/GR-05-1428 and Docket No. E002/GR-08-1065, the Commission approved passing the margins through to ratepayers using the FCA. In Docket No E002/GR-10-971, the Commission approved a Settlement Agreement that continued to pass margins through to ratepayers using the FCA.

Please explain why North Dakota customers are only receiving 85 percent of the asset based margins versus 100% if they are paying for all of the facilities that result in these margins? How long have North Dakota customers been receiving only 85% in comparison to the 100% received by MN and SD customers?

Response:

The different treatment in North Dakota reflects the Settlement Agreement approved in the Commission's December 31, 2008 Order Adopting Settlement in Case PU-07-776. The settlement states on page 13:

For purposes of determining the overall revenue requirement, the Parties agree to provide to ratepayers 85 percent of all asset-based and 50 percent of non-asset-based margins achieved by the Company through the fuel clause. Passing these credits directly to customers through the fuel clause as they are realized ensures that neither customers nor the

Company are disadvantaged by a non-representative margin forecast in the test year. By sharing the gains on asset-based sales, the Parties recognize that the Company is incented to maximize the benefit from these sales.

This settlement provision is noted on page 4 of the Compliance Matrix included with the Company's application. The sharing mechanism is included in our Commission-approved Fuel Clause Rider tariff (Section 5, Sheet 76.2).

The Company believes that sharing the benefits of the asset-based trading activity provides additional incentive for the Company to maximize the proceeds from these transactions. The Commission also recognized the value of a sharing approach as it approved the mechanism to direct 85 percent of asset-based trading margins and 50 percent of non-asset-based margins to North Dakota customers in Case PU-07-776.

The Minnesota Public Utilities Commission, by contrast, ordered the Company to flow 100 percent of asset based margins to its customers through the Minnesota Fuel Clause Adjustment in Docket No E002/GR-10-971 as part of a Settlement Agreement approved in the case. The Company does not provide any FCA sharing of non-asset based margins in Minnesota.

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Witness: Anne E. Heuer  
Preparer: Charles Burdick  
Title: Principal Rate Analyst  
Department: Revenue Requirements North  
Telephone: 612-330-6646  
Date: April 12, 2013

#### **Asset Based Trading Margin Adjustment**

The purpose of this adjustment is to remove from the test year the budgeted Asset Based Margin included in other revenues. Since these margins flow back to customers via the Fuel Clause Adjustment Factor, failure to remove them would understate the test year deficiency as revenues would be overstated.

**Northern States Power Company  
Summary of Asset Based Trading Margins**

	(1)	(2)	(3)	(4)	(5)	(6)
	<b>Asset Based</b>					
	<b>NSP System Electric</b>	<b>NSPM Electric</b>	<b>MN</b>	<b>ND</b>	<b>SD</b>	<b>Wholesale</b>
<b>Allocation/Portion</b>						
Method		Interchange	EEnergy			
Percentage		84.88%	87.51%	6.52%	5.91%	0.05%
<b>Margin Calculation</b>						
Trading revenues	37,965,575	32,225,636	28,202,201	2,100,757	1,905,018	17,660
Trading COGS	28,833,166	24,473,937	21,418,317	1,595,431	1,446,777	13,412
<b>Margin</b>	9,132,409	7,751,699	6,783,884	505,325	458,242	4,248
<b>Margin Sharing</b>						
Customer Portion			100%	85%	100%	100%
Shareholder Portion			0%	15%	0%	0%
Customer Amount			6,783,884	429,527	458,242	4,248
Shareholder Amount			-	75,799	-	-
<b>Adjustment</b>						
Customer credit applied in base data?			No	No	Yes	Yes
Shareholder exclusion applied in base data?			No	No	No	No
Customer adjustment amount		(7,213,410)	(6,783,884)	(429,527)	-	-
Shareholder adjustment amount		(75,799)	-	(75,799)	-	-
Total adjustment amount		(7,289,209)	(6,783,884)	(505,325)	-	-

**2013 NSP Asset Based Margin Budget**

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Revenue	6,001,127	5,499,798	1,367,597	1,898,778	3,582,099	780,596	2,220,531	3,043,857	2,752,869	4,140,012	3,939,855	2,738,458	37,965,575
Cost	4,265,229	4,092,126	1,040,249	1,540,244	3,074,593	687,224	1,618,691	2,324,475	2,180,852	2,975,654	2,875,628	2,158,200	28,833,166
Margin	1,735,898	1,407,672	327,348	358,534	507,506	93,372	601,840	719,382	572,017	1,164,357	1,064,226	580,258	9,132,409

#### Non-Asset Based Trading Margin Adjustment

The purpose of this adjustment is to remove from the test year the budgeted Non-Asset Based Margin included in other revenues. Since these margins either flow back to customers via the Fuel Clause Adjustment Factor, or accrue to the shareholder depending on the sharing percentage designated by the Commission, failure to remove them in total would understate the test year deficiency as revenues would be overstated.

**Northern States Power Company  
Summary of Non Asset Based Trading Margins**

	(1)	(2)	(3)	(4)	(5)
	Non Asset Based				
	NSPM Electric	MN	ND	SD	Wholesale
<b>Allocation/Portion</b>					
Method		EEnergy			
Percentage		87.51%	6.52%	5.91%	0.05%
<b>Margin Calculation</b>					
Trading revenues	108,000,000	94,515,984	7,040,412	6,384,420	59,184
Trading COGS	97,200,000	85,064,386	6,336,371	5,745,978	53,266
JOA to PSCO & SPS	(6,188,400)	(5,415,766)	(403,416)	(365,827)	(3,391)
JOA from PSCO	512,400	448,426	33,403	30,291	281
<b>Margin</b>	5,124,000	4,484,258	334,028	302,905	2,808
<b>Margin Sharing</b>					
Customer Portion		0%	50%	70%	0%
Shareholder Portion		100%	50%	30%	100%
Customer Amount		-	167,014	212,034	-
Shareholder Amount		4,484,258	167,014	90,872	2,808
<b>Adjustment</b>					
Customer FCA credit applied in base data?		No	No	Yes	Yes
Shareholder exclusion applied in base data?		No	No	No	No
Customer adjustment amount	(167,014)	-	(167,014)	-	-
Shareholder adjustment amount	(4,744,952)	(4,484,258)	(167,014)	(90,872)	(2,808)
Total adjustment amount	(4,911,966)	(4,484,258)	(334,028)	(90,872)	(2,808)

**2013 NSP Non-Asset Based Margin Budget**

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Revenue	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	108,000,000
Cost	8,100,000	8,100,000	8,100,000	8,100,000	8,100,000	8,100,000	8,100,000	8,100,000	8,100,000	8,100,000	8,100,000	8,100,000	97,200,000
Margin	900,000	900,000	900,000	900,000	900,000	900,000	900,000	900,000	900,000	900,000	900,000	900,000	10,800,000
NSP to PSCo/SPS	(515,700)	(515,700)	(515,700)	(515,700)	(515,700)	(515,700)	(515,700)	(515,700)	(515,700)	(515,700)	(515,700)	(515,700)	(6,188,400)
Share of PSC	42,700	42,700	42,700	42,700	42,700	42,700	42,700	42,700	42,700	42,700	42,700	42,700	512,400



**2013 Test Year Budget O&M Data  
Summarize Data by FERC Group**

Data					
FERC Group	Sum of SumOfAmount	Sum of SumOfMN	Sum of SumOfND	Sum of SumOfSD	Sum of SumOfWhls
A&G	246,243,879	215,247,038	15,599,702	15,302,395	94,478
CAcct	58,988,978	50,539,251	4,357,576	4,092,110	31
CInfo	119,066,192	117,553,566	504,700	1,007,923	1
CSales	54,577	49,773	2,461	2,346	0
Dist	110,589,463	96,728,524	6,527,750	7,333,166	3
Fuel	16,395,252	14,348,274	1,068,788	969,205	8,987
FuelC	326,177,982	285,454,008	21,263,216	19,282,012	178,746
FuelG	122,910,683	107,565,038	8,012,425	7,265,865	67,355
FuelN	117,919,461	103,196,980	7,687,052	6,970,809	64,620
FuelO	41,278	36,124	2,691	2,440	23
FuelPP	695,290,699	609,226,236	44,936,855	40,749,853	377,754
Production	746,064,426	655,430,175	45,529,729	44,668,054	436,285
Trans	241,889,618	212,660,630	14,568,264	14,517,467	143,162
<b>Grand Total</b>	<b>2,801,632,488</b>	<b>2,468,035,617</b>	<b>170,061,209</b>	<b>162,163,645</b>	<b>1,371,445</b>

FERC Group A&G

Allocate A&G to PTD

Sum of SumOfAmount		Total	Total	Total	Check
FERC PTDC	Total	P	T	D	
C	129,972,197	76,436,649	14,257,950	39,277,598	0
D	39,670,290			39,670,290	0
P	70,711,314	70,711,314			0
T	5,890,078		5,890,078		0
<b>Grand Total</b>	<b>246,243,879</b>	<b>147,147,963</b>	<b>20,148,028</b>	<b>78,947,888</b>	<b>0</b>

58.8100%      10.9700%      30.2200%

**Northern States Power Co (MN)  
Elec O&M Summary  
2013 Budget**

	<u>Total Company</u>	<u>Minnesota</u>	<u>N. Dakota</u>	<u>S. Dakota</u>	<u>Wholesale</u>
Fuel & Purchased Energy	1,278,735,356	1,119,826,660	82,971,027	75,240,184	697,485
Power Production Expense	746,064,243	655,430,175	45,529,729	44,668,054	436,285
Transmission Expense	241,889,523	212,660,630	14,568,264	14,517,467	143,162
Distribution Expense	110,589,443	96,728,524	6,527,750	7,333,166	3
Customer Accounting Expense	58,988,968	50,539,251	4,357,576	4,092,110	31
Cust Service & Info Expense	119,066,190	117,553,566	504,700	1,007,923	1
Sales Expense	54,580	49,773	2,461	2,346	0
Administrative & General	246,243,879	215,247,038	15,599,968	15,302,395	94,478
<b>Total Elec O&amp;M</b>	<b>2,801,632,182</b>	<b>2,468,036,617</b>	<b>170,061,475</b>	<b>162,163,645</b>	<b>1,371,445</b>
<b>Total Elec O&amp;M without COGS</b>	<b>1,522,896,826</b>	<b>1,348,209,957</b>	<b>87,090,448</b>	<b>86,923,461</b>	<b>673,960</b>
Payroll Taxes	31,397,750	27,512,686	1,931,929	1,938,506	14,629

Administrative & General	<u>Total Company</u>	<u>Production</u>	<u>Tranmission</u>	<u>Distribution</u>
NOTE: Entry for Total Company PTD	246,243,879	147,147,963	20,148,028	78,947,888
Payroll Taxes	<u>Total Company</u>	<u>Production</u>	<u>Tranmission</u>	<u>Distribution</u>
NOTE: Entry for Total Company PTD	31,397,750	22,994,884	2,113,123	6,289,744

## Nuclear Outage Update

This adjustment is an update to the budgeted Nuclear Amortization for forecasted increase in the PI Unit 1 Outage.

**NSPM Total Company Outage Amortization by FERC  
Change to Prairie Island #1**

FERC	NSPM 2013	Jurisdictional Demand Allocator				Sum of Juris	Check
		87.916% MN Juris	6.023% ND Juris	6.002% SD Juris	0.059% Whsl Juris		
517	495,824	435,910	29,862	29,758	294	495,824	(0)
532	1,513,642	1,330,740	91,162	90,844	896	1,513,642	0
<b>Total</b>	<b>2,009,466</b>	<b>1,766,650</b>	<b>121,024</b>	<b>120,602</b>	<b>1,190</b>	<b>2,009,466</b>	<b>0</b>

Note: this information was incorporated in the Interchange Agreement

**NSPM Total Company Outage Amortization by FERC**

Totals represent all three units. Changes only impact Prairie Island #1

**NEW**

<u>FERC</u>	<u>Factor</u>	<u>2012</u>	<u>2013</u>	<u>2014</u>
517	Demand	4,220,274	7,228,240	9,417,612
519	Demand	992,763	1,147,689	1,239,362
520	Demand	7,053,799	8,267,554	9,751,696
523	Demand	130,343	109,058	111,397
524	Demand	3,887,236	5,129,305	5,620,265
525	Demand	-	341	512
528	Energy	9,886,885	11,747,324	6,805,667
529	Demand	183,250	77,014	-
530	Energy	13,705,209	18,678,047	24,552,959
531	Energy	5,426,232	5,397,511	3,502,932
532	Demand	14,618,054	16,704,066	18,123,564
		<b>60,104,045</b>	<b>74,486,150</b>	<b>79,125,965</b>

**OLD**

<u>FERC</u>	<u>Factor</u>	<u>2012</u>	<u>2013</u>	<u>2014</u>
517	Demand	4,178,957	6,732,416	9,045,759
519	Demand	992,762	1,147,684	1,239,362
520	Demand	7,053,803	8,267,558	9,751,696
523	Demand	130,345	109,062	111,397
524	Demand	3,887,243	5,129,308	5,620,265
525	Demand	-	344	512
528	Energy	9,886,884	11,747,326	6,805,667
529	Demand	183,245	77,010	-
530	Energy	13,705,210	18,678,046	24,552,959
531	Energy	5,426,228	5,397,504	3,502,932
532	Demand	14,491,916	15,190,424	16,988,345
		<b>59,936,593</b>	<b>72,476,682</b>	<b>77,618,893</b>

**CHANGE**

<u>FERC</u>	<u>Factor</u>	<u>2012</u>	<u>2013</u>	<u>2014</u>
517	Demand	41,317	495,824	371,853
519	Demand	0	5	-
520	Demand	(4)	(4)	-
523	Demand	(2)	(4)	-
524	Demand	(7)	(3)	-
525	Demand	-	(3)	-
528	Energy	0	(2)	-
529	Demand	5	4	-
530	Energy	(1)	1	-
531	Energy	4	7	-
532	Demand	126,138	1,513,642	1,135,219
		<b>167,452</b>	<b>2,009,468</b>	<b>1,507,072</b>

\*\* Data from Jeff Robinson

## **Nuclear O&M Budget Adjustment**

**The purpose of this adjustment is to update the original Nuclear budgets for material cost changes identified after the original O&M budgets had been completed.**

**2013 North Dakota Electric Rate Case  
Summary of Nuclear O&M Budget Adjustments**

Object Account	Description	Monticello	Prairie Island	Total	Total Interchanged
712110	Contract Wk		44,000	44,000	
713050	Contract Wk		250,000	250,000	
714000	Materials	300,000	1,475,000	1,775,000	
723825	Fees	200,000		200,000	
723840	Fees	1,300,000		1,300,000	
713000	Contract Wk	2,900,000	3,180,000	6,080,000	
Grand Total		4,700,000	4,949,000	9,649,000	8,190,187

	MN Juris	ND Juris	SD Juris	Wholesale
EDemandProd	87.9164%	6.0227%	6.0017%	0.0592%
36 Month Interchange Factor	84.8812%	84.8812%	84.8812%	84.8812%
<b>Final Jurisdictional Allocator</b>	<b>74.6245%</b>	<b>5.1121%</b>	<b>5.0943%</b>	<b>0.0502%</b>

Object Account	MN Juris	ND Juris	SD Juris	Wholesale	Sum of States	Check
712110	32,835	2,249	2,241	22		
713050	186,561	12,780	12,736	126		
714000	1,324,585	90,740	90,424	892		
723825	149,249	10,224	10,189	100		
723840	970,118	66,458	66,226	653		
713000	4,537,169	310,818	309,734	3,055		
Grand Total	7,200,520	493,269	491,550	4,848	8,190,187	0

### **Nuclear Retention Adjustment**

**This adjustment is being made to account for nuclear retention agreements that were issued to key nuclear operations employees after the budget cycle was completed and therefore not included in the original budget calculations for 2013.**

**Summary of Nuclear Retention Adjustment**

2013 Budget Adjustment

Total Amount of Retention Adjustment

Object Account	Description	Total	Total Interchanged
711230	Other Comp	1,383,042	1,173,942
	Long Term Incentive	124,615	105,775
<b>Total</b>		<b>1,507,657</b>	<b>1,279,717</b>

Calculate Jurisdictional and Interchange Weighted Allocators

	MN Juris	ND Juris	SD Juris	Wholesale
EdemandProd	87.916%	6.023%	6.002%	0.059%
36 Month Interchange Factor	84.88%	84.88%	84.88%	84.88%
<b>Final Jurisdictional Allocator</b>	<b>74.62%</b>	<b>5.11%</b>	<b>5.09%</b>	<b>0.05%</b>

Adjustment Amount Allocated to Jurisdiction and Interchanged

Description	MN Juris	ND Juris	SD Juris	Wholesale	Sum of States	Check
Other Compensation	1,032,088	70,703	70,456	695	1,173,942	0
Long Term Incentive	92,994	6,370	6,348	63	105,775	0
<b>TOTAL</b>	<b>1,125,082</b>	<b>77,073</b>	<b>76,804</b>	<b>758</b>	<b>1,279,717</b>	<b>0</b>

Northern States Power Co (Minnesota)  
 Adjustment to 2013 Test Year O&M Expense  
 Nuclear Generation Management Retention Program

Background / Description:

Xcel Energy Human Resources has approved a management retention program for critical positions in Nuclear Generation. This program provides retention payouts, 90% in cash and 10% in long-term incentives (LTI). The majority of the cash payouts (77.8%) are time-based and are earned over 20 to 27 month retention period ending in 2014. The remaining cash bonuses (22.2%) are performance-based based on criteria established for program participants, which have measurement dates ranging from late 2012 through 2014.

In September 2012, 32 Nuclear employees were identified as being in critical positions and are eligible for retention bonuses. The following summarizes the estimated 2013 test year cost of the cash retention bonuses awarded under the program for Nuclear employees, assuming straight-line amortization of the time-based portion of the program over periods through 2014, and recognition of the performance-based portion of the program ratably over various measurement dates through 2014.

Location	Department Name	Business Unit Cost Center	Object Account (Other Compensation)	2013 Test Year Expense
Monticello Plant	MT Site Management	257200	711270	\$ 66,667
Monticello Plant	MT Project Mgmt Office	257229	711270	\$ 41,778
Prairie Island Plant	PI Plant Management	257405	711270	\$ 187,250
Prairie Island Plant	PI Operations Support	257423	711270	\$ 173,875
Prairie Island Plant	PI Site Management	257400	711270	\$ 164,250
Prairie Island Plant	PI Engineering Design	257453	711270	\$ 93,625
Prairie Island Plant	PI Nuclear Oversight	257402	711270	\$ 40,125
Prairie Island Plant	PI Project Management	257430	711270	\$ 80,250
Prairie Island Plant	PI Radiological Protection	257417	711270	\$ 26,750
Prairie Island Plant	PI Chemistry	257406	711270	\$ 26,750
Prairie Island Plant	PI Outage	257427	711270	\$ 26,750
Prairie Island Plant	PI Work Control Center	257424	711270	\$ 26,750
Prairie Island Plant	PI Business Planning	257462	711270	\$ 20,889
Fleet Services (Marq Plaza)	HQ Engineering	257112	711270	\$ 94,000
Fleet Services (Marq Plaza)	HQ Project Management Office	257105	711270	\$ 62,667
Fleet Services (Marq Plaza)	HQ Fuels	385350	711270	\$ 31,333
Fleet Services (Marq Plaza)	HQ Ops Standardization	257116	711270	\$ 31,333
Fleet Services (Marq Plaza)	HQ Chief Nuclear Officer Support	257117	711270	\$ 41,778
Fleet Services (Marq Plaza)	HQ Training	257106	711270	\$ 31,333
Fleet Services (Marq Plaza)	HQ Emergency Preparedness	257122	711270	\$ 31,333
Fleet Services (Marq Plaza)	FT Nuclear Supply Chain	257115	711270	\$ 31,333
Fleet Services (Marq Plaza)	FT Nuclear Security	257114	711270	\$ 31,333
Fleet Services (Marq Plaza)	HQ Nuclear Analysis & Design	257108	711270	\$ 20,889
<b>Total cash-based portion of Nuclear retention program recognized in 2013</b>				<b>\$ 1,383,042</b>

<b>Number of Participants</b> (including loaned INPO executive)	<b>33</b>
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<b>Program Cost:</b>	Per detailed schedule by critical position
Cash Bonuses (90%)	\$ 2,580,000
Long-term incentives (10%)	\$ 270,000
<b>Total Retention Awards</b>	<b>\$ 2,850,000</b>

<b>Cost Recognized by Year:</b>			
	<b>Cash</b>		<b>LTI</b>
2012	\$ 522,792	\$	20,769
2013	\$ 1,383,042	\$	124,615
2014	\$ 674,167	\$	124,615
<b>Total</b>	<b>\$ 2,580,000</b>	<b>\$</b>	<b>270,000</b>

## Purpose

This adjustment removes the MISO revenues and expenses associate with transmission projects currently in Construction Work in Progress (CWIP). Since North Dakota rule making does not allow long term CWIP in rate base. The North Dakota jurisdictional share of the transmission revenue and expenses associated with CWIP transmission projects is being excluded from the test year.

2013 CWIP Related  
MISO Revenues and Expenses  
As Allocated to the North Dakota Retail Jurisdiction

<u>2013 MISO Attachment GG &amp; MM</u>		<u>Revenue</u>	<u>Expense</u>	<u>ND Demand</u>	<u>IA Demand</u>	<u>ND Adj Revenue</u>	<u>ND Adj Expense</u>
GG	Twin Cities - Fargo CWIP	12,745,095	6,465,503	6.0227%	84.8812%	651,547	330,526
GG	Twin Cities - Rochester CWIP	3,326,441	1592683.561	6.0227%	84.8812%	170,052	81,420
MM	Brookings 2013 CWIP	<u>26,728,403</u>	<u>2,447,648</u>	6.0227%	84.8812%	<u>1,366,393</u>	<u>125,127</u>
	<b>Totals</b>	<b>42,799,939</b>	<b>10,505,835</b>			<b>2,187,993</b>	<b>537,073</b>
		<u>IA Demand</u>	<u>IA Demand</u>				
		84.8812%	84.8812%				
	<b>Adjustment</b>	<b>(36,329,102)</b>	<b>(8,917,479)</b>			<b>(2,187,993)</b>	<b>(537,073)</b>

## **North Dakota Additional Distribution Line Crew Adjustment**

The purpose of this adjustment is to update the original operating and maintenance budgets for additional linemen in the North Dakota jurisdiction. An increase in linemen is necessary in North Dakota to meet growing need and maintain reliable service.

## 2013 North Dakota Budget Adjustment for Additional Distribution Line Crews

### TOTAL

	Annual O&M Costs	Customer Allocator	Allocated O&M Costs	
Labor Prod & Non Prod (Excluding Benefits)	\$ 145,110	96.3323%	\$ 139,788	
O&M Overtime Hours	\$ 43,810	96.3323%	\$ 42,203	
Employee Expenses (per diem, etc.)	\$ 1,333	96.3323%	\$ 1,284	
Small O&M Tools	\$ 2,000	96.3323%	\$ 1,927	
Trucks	\$ 51,224	96.3323%	\$ 49,345	
FR Clothing	\$ 1,280	96.3323%	\$ 1,233	
<b>TOTAL</b>	<b>\$ 244,757</b>		<b>\$ 234,547</b>	Total ND Adjustment
			\$ 10,210	Total MN Adjustmnet
Check	\$ -			

#### Notes:

- Reflects a start date of 4/1/2013
- Does not include Labor Loadings

### Bad Debt Update Adjustment

This adjustment updates bad debt expenses to reflect the latest forecast for 2013 commodity revenues.

NSP Minnesota  
 Bad Debt Summary  
 Updated Level

Updated Commodity Bad Debt Calculation		
Billed Commodity Revenue		3,611,552,822
Commodity Bad Debt Ratio		0.39%
Commodity Only	100.0%	<u>14,241,979</u>

Year	Utility	FERC	FERC Desc	Bus Area Desc		2013 Budget	MN Juris	ND Juris	SD Juris	Wh Juris	AllocatorID	Acct Desc
2013	Electric	904	Cust Acct Uncollect	Corporate Services	72.6%	10,343,849	10,343,849	-	-	-	EDirectMN	723055 Energy
2013	Electric	904	Cust Acct Uncollect	Corporate Services	4.5%	646,486	-	646,486	-	-	EDirectND	723055 Energy
2013	Electric	904	Cust Acct Uncollect	Corporate Services	4.2%	600,171	-	-	600,171	-	EDirectSD	723055 Energy
2013	Gas	904	Cust Acct Uncollect	Corporate Services	16.6%	2,365,137	2,365,137	-	-	-	GDirectMN	723055 Energy
2013	Gas	904	Cust Acct Uncollect	Corporate Services	2.0%	286,335	-	286,335	-	-	GDirectND	723055 Energy
Jurisdictional Commodity Bad Debts						<u>14,241,978</u>						

Updated Electric Bad Debt Expense

2013	Electric	904	Cust Acct Uncollect	Corporate Services		10,343,849	10,343,849	-	-	-	EDirectMN	723055 Energy
2013	Electric	904	Cust Acct Uncollect	Corporate Services		646,486	-	646,486	-	-	EDirectND	723055 Energy
2013	Electric	904	Cust Acct Uncollect	Corporate Services		600,171	-	-	600,171	-	EDirectSD	723055 Energy
2013	Electric	904	Cust Acct Uncollect	Corporate Services		104,086	91,110	6,640	6,336	-	ECustomerMN/SD/ND	723060 Non-Energy
2013	Electric	904	Cust Acct Uncollect	Distribution Operations		200,433	200,433	-	-	-	EDirectMN	723060 Non-Energy
Total Electric Bad Debts						<u>11,895,026</u>	<u>10,635,393</u>	<u>653,126</u>	<u>606,507</u>	-		

Updated Gas Bad Debt Expense

2013	Gas	904	Cust Acct Uncollect	Corporate Services		2,365,137	2,365,137	-	-	-	GDirectMN	723055 Energy
2013	Gas	904	Cust Acct Uncollect	Corporate Services		286,335	-	286,335	-	-	GDirectND	723055 Energy
2013	Gas	904	Cust Acct Uncollect	Corporate Services		25,740	23,168	2,572	-	-	GCustomerMN/SD/ND	723060 Non-Energy
2013	Gas	904	Cust Acct Uncollect	Distribution Operations		49,567	49,567	-	-	-	GDirectMN	723060 Non-Energy
Total Gas Bad Debts						<u>2,726,779</u>	<u>2,437,871</u>	<u>288,907</u>	-	-		

**Recap of Bad Debt Update Calculation**

		Updated Calculation	<u>Original Budget</u>	Final Adj <u>Level</u>	<u>Breakdown of Updated Bad Debts</u>			
					<u>Total Company</u>	<u>Mn Jur</u>	<u>ND Jur</u>	<u>SD Jur</u>
Commodity Bad Debt - Mn Electric	a	10,343,849	11,501,989	(1,158,140)	10,343,849	10,343,849		
Commodity Bad Debt - ND Electric	a	646,486	718,869	(72,383)	646,486		646,486	
Commodity Bad Debt - SD Electric	a	600,171	667,369	(67,198)	600,171			600,171
Customer Non Comm/Non Energy	b	104,086	104,086	-	104,086	91,110	6,640	6,336
Dist Operation Non Comm/Non Energy	c	200,433	200,433	-	200,433	200,433	-	-
<b>Total Electric</b>		<u>11,895,026</u>	<u>13,192,747</u>	<u>(1,297,721)</u>	<u>11,895,026</u>	<u>10,635,393</u>	<u>653,126</u>	<u>606,507</u>
Commodity Bad Debt - Mn Gas	a	2,365,137	2,629,947	(264,810)	2,365,137	2,365,137		
Commodity Bad Debt - ND Gas	a	286,335	318,394	(32,059)	286,335		286,335	
Customer Non Comm/Non Energy	b	25,740	25,740	-	25,740	23,168	2,572	
Dist Operation Non Comm/Non Energy	c	49,567	49,567	-	49,567	49,567	-	
<b>Total Gas</b>		<u>2,726,779</u>	<u>3,023,648</u>	<u>(296,870)</u>	<u>2,726,778</u>	<u>2,437,871</u>	<u>288,907</u>	<u>-</u>
<b>Recap</b>								
Commodity Bad Debts	Sum a	14,241,978	15,836,568	(1,594,590)	14,241,978	12,708,986	932,821	600,171
Customer Non Comm/Non Energy	Sum b	129,827	129,827	-	129,826	114,278	9,212	6,336
Dist Operations Non Comm/Non Energy	Sum c	250,000	250,000	-	250,000	250,000	-	-
		<u>14,621,805</u>	<u>16,216,395</u>	<u>(1,594,590)</u>	<u>14,621,804</u>	<u>13,073,264</u>	<u>942,033</u>	<u>606,507</u>

## **Economic Development**

**The purpose of the Economic Development adjustment is to bring into the cost of service the economic development donations budgeted for the test period. Donations are budgeted in a FERC account that is not included in the base data for the test year.**

**2013 Budget Economic Development Adjustment**

Year	Utility Desc	CFR FERC Cd AC22	CFR FERC Desc AC22	Bus Area Cd CC1	Bus Area Desc CC1	CC1 Bus Area Cd	Dec Bud YTD	SumOfMN	SumOfND	SumOfSD	SumOfWhls	Location Allocator	Lvl 0 Desc BC24	Lvl 2 Desc BC26
2013	Electric	426.1	Donations	GP	Group President	GP	40,867		40,867			EDirectND	NSPM President	NSPM ND Jurisdiction
2013	Electric	426.1	Donations	GP	Group President	GP	51,406		51,406			EDirectND	NSPM President	NSPM ND Jurisdiction
2013	Electric	426.1	Donations	GP	Group President	GP	78,620		78,620			EDirectND	NSPM President	NSPM ND Jurisdiction
2013	Electric	426.1	Donations	GP	Group President	GP	27,683			27,663		EDirectSD	NSPM President	NSPM SD Jurisdiction
2013	Electric	426.1	Donations	GP	Group President	GP	41,512			41,512		EDirectSD	NSPM President	NSPM SD Jurisdiction
2013	Electric	426.1	Donations	GP	Group President	GP	92,209			92,209		EDirectSD	NSPM President	NSPM SD Jurisdiction
2013	Electric	426.1	Donations	GP	Group President	GP	2,305	2,305				EDirectMN	NSPM President	NSPM Comm Relations
2013	Electric	426.1	Donations	GP	Group President	GP	10,088	10,088				EDirectMN	NSPM President	NSPM Comm Relations
2013	Electric	426.1	Donations	GP	Group President	GP	70,283	70,283				EDirectMN	NSPM President	NSPM Comm Relations
<b>TOTAL</b>							<b>414,953</b>	<b>82,676</b>	<b>170,893</b>	<b>161,384</b>	<b>0</b>			

Cost Sharing Calculation:  
 50% of Below The Line Donations Qualifying For Recovery State of Mn 41,338  
 100% of Below The Line Donations Qualifying For Recovery State of ND 170,893  
 50% of first \$100k of Below The Line Donations Qualifying For Recovery State of SD 50,000  
**Total Electric Adjustment 262,231 41,338 170,893 50,000**

**NSP Mn Electric Economic Development  
Rate Case Adjustment  
Budget Year 2013**

<b>Recap of Adjustment</b>	<b>Total Co</b>	<b>MN</b>	<b>ND</b>	<b>SD</b>	
Electric O&M Reduction	(8,018)	(8,018)	-	-	Removal of non allowed ED program costs included in O&M
Electric ED Donation Inclusion	262,231	41,338	170,893	50,000	Inclusion of allowable ED donations
<b>Net Adjustment to Econ Dev</b>	<b>254,213</b>	<b>33,320</b>	<b>170,893</b>	<b>50,000</b>	

**Association Dues**

**The purpose of the Association Dues is to reduce administrative and general expenses for dues paid to either social organizations or organizations not associated with the State of North Dakota. It also increases A&G expenses by the amount of dues paid to North Dakota Area Chambers of Commerce.**

## 2013 Budget Association and Utility Dues

	<u>2013 Budget</u>	
<b>Total NSP-MN Electric Association Dues</b>	1,369,927	
Total Exclusions		
Budgeting Error	(33,348)	
Lobbying/Political Organizations	(4,725)	
No Detail Provided	(19,064)	
<b>Total NSP-MN Electric Exclusions</b>	<u>(57,137)</u>	
ND Juris Electric Excluded from Test Year	(3,600)	<b>A</b>

Note: This portion of the Total Adjustment removes non-recoverable association or utility dues

## 2013 Budget Chamber of Commerce Dues

	<u>2013 Budget</u>	
<b>Total NSP-MN Electric Chamber Dues</b>	276,263	
Total Exclusions		
United States Chamber	(18,142)	
No specific Chamber Identified	(724)	
Local Area Chamber Lobbying	(11,848)	
<b>Net NSP-MN Electric</b>	<u>245,549</u>	
ND Juris Electric Included in Test Year	22,760	<b>B</b>

Note: This portion of the Total Adjustment includes below-the-line Chamber of Commerce dues

## Total 2013 Dues Adjustment

<b>TOTAL ND Juris Electric Dues Adjustment</b>	<b>19,160</b>	<b>Sum A + B</b>
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## Donations

The Company is asking to recover 50% of its charitable donations associated with the electric service territory in the North Dakota jurisdiction. The Company records donations in a FERC account that is excluded from the test year base data (below the line). This adjustment reclassifies 50% of the eligible below the line donations into the test year.

**2013 Budget Donations and Community Sponsorship**  
**Budgeted Amount must be provided FOR EACH ORGANIZATION**

CFR FERC Cd AC22

Sum of 2013 Budget				Detailed Data for 2013 BUDGET										
Object Account	Allocated Posting Full Ac	Utility Desc	Subledger	Reg Loc Desc BC6	Organization(s) Receiving Sponsorship	State	Allocator	NSPM Elec Included	MN Included	ND Included	SD Included	Whsl Included		
723833	Charitable Contributions	Electric	620210	MN/SD/ND	National Conference on LGBT Equality	National Org	ECustomerMN/SD/ND	231	202	15	14	0		
723833	Charitable Contributions	Electric	0	MN/SD/ND	University of Minnesota	MN	ECustomerMN/SD/ND	11,526	10,089	735	702	0		
723833	Charitable Contributions	Electric	0	North Dakota	Made up of Following Organizations:		EDirectND	40,867	0	40,867	0	0		
					University of North Dakota Foundation	ND								
					Salvation Army Fargo Corp	ND								
					Salvation Army - Minot	ND								
					Habitat for Humanity International Inc	ND								
					Hospice of the Red River Valley	ND								
					Altru Health Foundation	ND								
					Minot Symphony Association Inc	ND								
					Minot Indoor Rodeo Inc.	ND								
					Audubon Society	ND								
					Fargo Theatre Management Corp	ND								
					Grand Forks Parks and Recreation	ND								
					Grand Forks Special Olympics Inc	ND								
					Grand Forks Public Schools	ND								
					Trinity Health Foundation	ND								
					Village Family Service Center	ND								
723833	Charitable Contributions	Electric	0	South Dakota	Made up of Following Organizations:		EDirectSD	27,663	0	0	27,663	0		
					Sioux Falls Area Chamber of Commerce	SD								
					Catholic Foundation for Eastern South	SD								
					McCrossan Boy's Ranch	SD								
					American Cancer Society	SD								
					Sioux Falls Area Chamber of Commerce	SD								
					South Dakota Symphony	SD								
					Children's Miracle Network	TX								
					Sioux Falls Area Catholic Schools	SD								
723833	Charitable Contributions	Electric	0	Minnesota	Made up of Following Organizations:		EDirectMN	52,283	52,283	0	0	0		
					American Red Cross	TX								
					The Foundation for Bayport Public Library	MN								
					Volunteers Enlisted to Assist People	MN								
					Minneapolis Riverfront Partnership	MN								
					Downtown Council	MN								
					MCTC Foundation	MN								
					Catholic Charities	MN								
					Minnesota Zoo Foundation	MN								
					Knollwood Liquor Store	MN								
					Mankato Area Hockey Association	MN								
					Razoo Donations	MN								
					ARC Local Chapter	MN								
					LLS-E Fundraising	MN								
					Williams-Sonoma 0717	MN								
					HIS	MN								
723833	Charitable Contributions	Electric	811203	Minnesota	CENTRAL FREEDOM SCHOOL	MN	EDirectMN	2,305	2,305	0	0	0		
723833	Charitable Contributions	Electric	110	MN/SD/ND	Made up of Following Organizations:		ECustomerMN/SD/ND	1,811	1,585	116	110	0		
								136,680	66,464	41,733	28,489	0		
<b>723833 Charitable Contributions Total</b>														
723834	Community Sponsorships	Electric	243324	Minnesota	Mower County Fair	Dexter Sun	EDirectMN	2,766	2,766	0	0	0		
723834	Community Sponsorships	Electric	171	MN/SD/ND	Diversity & Inclusion Events	All of Xcel	ECustomerMN/SD/ND	2,897	2,536	185	176	0		
723834	Community Sponsorships	Electric	620210	MN/SD/ND	Made up of Following Organizations:		ECustomerMN/SD/ND	12,356	10,816	788	752	0		
					MN Women's Lawyers	MN								
					MN Association of Black Lawyers	MN								
					Twin Cities Diversity in Practice	MN								
723834	Community Sponsorships	Electric	121	MN/SD/ND	Made up of Following Organizations:		ECustomerMN/SD/ND	7,244	6,341	462	441	0		
					William Mitchell Law School Board of	MN								
					Colorado University	CO								
					Riverfront Corporation	MN								
					Metro State University Board	MN								
723834	Community Sponsorships	Electric	499819	MN/SD/ND	Made up of Following Organizations:		ECustomerMN/SD/ND	3,711	3,248	237	226	0		

**2013 Budget Donations and Community Sponsorship**  
**Budgeted Amount must be provided FOR EACH ORGANIZATION**

CFR FERC Cd AC22

Sum of 2013 Budget				Detailed Data for 2013 BUDGET					NSPM Elec	MN Included	ND Included	SD Included	Whtl Included
Object Account	Allocated	Posting Full Ac	Utility Desc	Subledger	Reg Loc Desc BC6	Organization(s) Receiving Sponsorship	State	Allocator	included				
						American Lung Association of MN	MN						
						BOMA St Paul	MN						
						Minnesota Chief Engineers Guild	MN						
						Central Minnesota Builders Association	MN						
						Mid Minnesota Builders Association	MN						
723834	Community Sponsorships		Electric	0	North Dakota	Made up of Following Organizations:		EDirectND	51,406	0	51,406	0	0
						Minot State University	ND						
						Artwise	ND						
						Journal Communications	TN						
						The Chamber	ND						
723834	Community Sponsorships		Electric	0	MN/SD/ND	Made up of Following Organizations:		ECustomerMN/SD/ND	152,185	133,213	9,709	9,264	0
						St. Paul Area Chamber	MN						
						Minneapolis Downtown Council	MN						
						Minneapolis Regional Chamber	MN						
						St. Paul River Center	MN						
						St. Paul Riverfront Corporation	MN						
						Minnesota Wild Hockey	MN						
						Minneapolis Aquatennial	MN						
						Great River Greening	MN						
						Ordway Circle of Stars	MN						
						BB MN Orchestra BBMS	MN						
						Como Friends	MN						
						Junior Achievement of MDWS	MN						
						YWCA of Minneapolis	MN						
						TC Habitat for Humanity	MN						
						Just Give	MN						
						Razoo Donations	MN						
						First Giving.com	MN						
						MN Childrens Museum	MN						
						Childrens Heartlink	MN						
						BB Boy Scouts NSC	MN						
						The Children's Theatre	MN						
						Wilder Foundation	MN						
						Friends of the St. Paul Library	MN						
						River Valley Girl Scouts	MN						
						Minnesota Fire Service Foundation	MN						
						Minneapolis Downtown Council	MN						
						Metro State Foundation	MN						
						Northern Star Boy Scouts	MN						
						Bridging, Inc.	MN						
						Minnesota High Tech Association	MN						
723834	Community Sponsorships		Electric	0	Minnesota	Made up of Following Organizations:		EDirectMN	52,839	52,839	0	0	0
						City of Monticello	MN						
						Red Wing Water Park	MN						
						City of St. Cloud	MN						
						Fireworks Fund	MN						
						City of Belview	MN						
						American Association of University	MN						
						City of St. Paul	MN						
						East Side Neighborhood	MN						
						Minneapolis Regional Chamber of	MN						
						Culture, Inc.	MN						
						Eden Prairie Chamber of Commerce	MN						
						St. Paul Area Chamber of Commerce	MN						
						City of Cold Spring	MN						
						River City Days Association	MN						
						Waconia Chamber of Commerce	MN						
723834	Community Sponsorships		Electric	0	Minnesota	Made up of Following Organizations:		EDirectMN	3,073	3,073	0	0	0
						Central Minnesota Builders Association	MN						

**2013 Budget Donations and Community Sponsorship**  
**Budgeted Amount must be provided FOR EACH ORGANIZATION**

CFR FERC Cj AC22

Sum of 2013 Budget				Detailed Data for 2013 BUDGET					NSPM Elec	MN Included	ND Included	SD Included	What Included
Object Account	Allocated Posting Full Ac	Utility Desc	Subledger	Reg Loc Desc BC6	Organization(s) Receiving Sponsorship	State	Allocator	Included					
					Woodbury Chamber of Commerce	MN							
					BREDE	MN							
					Xcel Energy Company Store	MN							
					Sensible Land Use Coalition	MN							
					Mid Minnesota Builders Association	MN							
					Central Minnesota Builders Association	MN							
					Sartell Chamber of Commerce	MN							
					Central Minnesota Builders Association	MN							
					Mid Minnesota Builders Association	MN							
					Builders Association of the ???	MN							
					Builders Association of the ???	MN							
					Rotary Club of North Branch	MN							
					Mid Minnesota Builders Association	MN							
723834	Community Sponsorships	Electric	110	MN/SD/ND	Big Brothers Big Sisters	CO	ECustomerMN/SD/ND	1 811	1 585	116	110	0	
723834	Community Sponsorships	Electric	190	MN/SD/ND	Made up of Following Organizations:		ECustomerMN/SD/ND	54 224	47 464	3,459	3 301	0	
723834	Community Sponsorships	Electric	190	MN/SD/ND	Big Brothers Big Sisters	CO	ECustomerMN/SD/ND	3 137	2 746	200	191	0	
723834	Community Sponsorships	Electric	110	MN/SD/ND	Women's Innovation Network	MN, CO, TX, WI	ECustomerMN/SD/ND	724	634	46	44	0	
<b>723834 Community Sponsorships Total</b>								<b>348,373</b>	<b>267,261</b>	<b>66,608</b>	<b>14,505</b>	<b>0</b>	
<b>Grand Total</b>								<b>485,069</b>	<b>333,728</b>	<b>108,340</b>	<b>42,994</b>	<b>0</b>	

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Xcel Energy

Case No.: PU-12-813

Response To: North Dakota Public Service Commission      Data Request No.      NDPSC-2-013

Requestor: Michael Diller & Sara Cardwell

Date Received: March 8, 2013

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Question:

Heuer Question:

On page 31 of 62 of Exhibit (AEH-1), Schedule 12 under method of allocation for Aviation Distribution it states: "Any spousal use of the aircraft must be approved and is billed to the holding company." Why wouldn't an employee be responsible for the expenses of having a spouse use the Company aircraft? How does spousal use of the aircraft fit into the Company's Aviation Services Analysis? Have any spouses traveled on the Company aircraft and thereby required an employee to use commercial transportation? If this has happened provide dates and costs for these expenses over the last five years. Please further explain how this was factored into the Aviation Services Analysis.

Response:

The Aviation Services department in Xcel Energy Services Inc. (Service Company) is responsible for managing and operating the two leased corporate aircraft used by the Xcel Energy system of companies. Aviation costs are billed out across Xcel Energy's legal entities using the corporate governance three-factor allocator based on revenues, assets and number of employees. Approximately 89% of the department's costs are charged to the four operating companies (NSPM, NSPW, PSCo and SPS). In addition, approximately 10% of the department's costs are charged to the Xcel Energy Inc. Holding Company, and not reflected in rates charged to customers.

As shown in Table I below, on average between 2008 and 2012, non-employee travel accounts for approximately 1% of the total number of passengers transported. Non-employee travel has been provided only for Company executive employees and, on occasion, for members of the Xcel Energy Inc. Board of Directors.

**Table I - Corporate Aviation Non-Employee Travel**

<b>Year</b>	<b>Total Passengers</b>	<b>Non-Employee Passengers</b>	<b>% Non-Employee Passengers</b>
2008	4,233	40	0.9%
2009	3,056	55	1.8%
2010	3,892	18	0.5%
2011	4,256	55	1.3%
2012	3,532	16	0.5%
<b>Total</b>	<b>18,969</b>	<b>184</b>	<b>1.0%</b>

Attendance of executive and board member spouses sometimes occurs for certain corporate and Board of Director functions.

Spousal passengers are included as Non-employee passengers within the Company's Aviation Services analysis. The Value per Man Hour (VMH) multiplier factor assumption is set to 0 for the purpose of the benefit vs. cost analysis.

The Company does not track whether other employees were ever required to use alternative travel arrangements because of spousal or non-employee travel.

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Witness: Anne E Heuer  
Preparer: Tim Searle  
Title: Director, Regulatory Projects  
Department: Revenue Requirements  
Telephone: 612-330-6881  
Date: March 20, 2013

## Aviation Adjustment

This Company currently has two corporate airplanes that it maintains. This adjustment excludes a portion of the cost of the corporate aviation department so that the Company is only seeking recovery of the costs to maintain a single airplane. This treatment is consistent with the previous North Dakota rate case.

**2013 Budget Corporate Aviation Adjustment  
Adjustment To A&G**

Adjustment to remove 50% of Budgeted Amount

**Allocated to Jurisdiction Using 2Factor Allocator**

<b>Electric</b>	<b>Total</b>	<b>MN</b>	<b>ND</b>	<b>SD</b>	<b>Whisl</b>
Amount Budgeted	1,698,536	1,491,334	104,127	102,382	693
Adjustment Amount at 50%	(849,268)	(745,667)	(52,064)	(51,191)	(347)
Payroll Taxes	21,865	19,198	1,340	1,318	9
Adjustment Amount at 50%	(10,933)	(9,599)	(670)	(659)	(5)
P 58.81%	(499,455)		(6,429)		
T 10.97%	(93,165)		(1,199)		
D 30.22%	<u>(256,649)</u>		<u>(3,304)</u>		
	<u>(849,268)</u>		<u>(10,933)</u>		

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Xcel Energy

Case No.: PU-12-813

Response To: North Dakota Public Service Commission      Data Request No.      NDPSC-5-045

Requestor: Snavely King

Date Received: March 29, 2013

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Question:

Witness: Anne E. Heuer-Revenue Requirement (Exhibit AEH-1)

Please provide a breakdown of wages, employee benefits, overheads by type, employment taxes and other charges to the various O & M expense labor categories for 2011, 2012 and projected 2013.

Response:

Please see Attachment A to this response for a breakdown of O&M expenses by labor category for 2011 actual, 2012 actual, and 2013 budget. The breakdown is provided for NSPM electric utility and North Dakota electric utility, net of Interchange Agreement billings to NSP-Wisconsin.

The O&M expenses provided in Attachment A do not reflect \$300,000 in labor-related rate case adjustments. The 2013 North Dakota test year was reduced by \$300,000 to remove any labor-related expenses we are not proposing to be recovered from ratepayers, such as long-term incentive. The 2012 actual data provided should be considered preliminary until the Company files its jurisdictional annual reports.

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Witness: Anne E. Heuer  
Preparer: Mary Pope  
Title: Senior Rate Analyst  
Department: Revenue Requirements North  
Telephone: 612-330-6574  
Date: April 22, 2013

Northern States Power Company  
Electric Utility - State of North Dakota

Case No. PU-12-813  
NDPSC Data Request 5-045  
Attachment A - Page 1 of 1

O&M Expenses by Labor Category  
(\$)

Labor Category	NSPM Electric			North Dakota Electric <sup>1</sup>		
	2011	2012	2013	2011	2012	2013
Fuel Handling - Labor	6,229,244	6,709,108	5,984,691	325,810	350,341	328,187
Fuel Handling - Attrition	0	0	(239,388)	0	0	(13,129)
Fuel Handling - Incentive (Labor Loading)	12,846	13,116	15,377	672	686	844
Fuel Handling - Injury and Damages (Labor Loading)	173,676	171,146	138,739	9,988	9,852	8,355
Fuel Handling - Insurance	1,387,905	1,483,729	1,298,627	79,819	85,421	78,214
Fuel Handling - Non Productive Labor	1,186,437	1,297,875	1,207,049	62,054	67,775	66,190
Fuel Handling - Other Compensation	181,622	218,760	0	9,498	11,424	0
Fuel Handling - Overtime	2,084,740	1,657,359	2,003,131	109,039	86,547	109,846
Fuel Handling - Payroll Taxes	832,340	878,001	771,456	47,870	50,535	46,461
Fuel Handling - Pension	603,474	1,148,100	1,203,562	34,711	66,100	72,487
Fuel Handling - Premium Time	173,885	194,113	0	9,096	10,137	0
Fuel Procurement - Attrition	0	0	(17,411)	0	0	(955)
Fuel Procurement - Incentive (Labor Loading)	83,422	106,705	63,012	4,363	5,573	3,456
Fuel Procurement - Injury and Damages (Labor Loading)	1,438	1,438	1,465	83	84	89
Fuel Procurement - Insurance	78,907	77,912	83,865	4,539	4,619	5,050
Fuel Procurement - Labor	471,559	439,967	435,243	24,665	22,977	23,869
Fuel Procurement - Non Productive Labor	77,252	73,805	89,336	4,040	3,855	4,899
Fuel Procurement - Payroll Taxes	44,565	55,775	39,360	2,563	3,210	2,370
Fuel Procurement - Pension	72,603	111,340	89,159	4,177	6,601	5,369
Nuclear Fuel Procurement - Labor	394,413	411,379	496,535	19,009	19,887	25,384
Nuclear Fuel Procurement - Non Productive Labor	78,961	72,261	0	3,806	3,494	0
Nuclear Fuel Procurement - Payroll Taxes	46,944	36,133	0	2,700	2,080	0
Nuclear Fuel Procurement - Pension	33,427	26,742	0	1,922	1,540	0
Nuclear Fuel Procurement - Injury and Damages (Labor Loading)	7,487	935	0	431	54	0
Nuclear Fuel Procurement - Insurance	75,990	46,571	0	4,370	2,681	0
Productive Labor	251,566,388	253,288,337	264,541,105	13,673,802	13,393,236	14,762,491
Non Productive Labor	42,873,640	44,381,694	50,835,077	2,348,967	2,355,294	2,859,988
Attrition	0	0	(10,587,619)	0	0	(590,849)
Incentive (Labor Loading)	9,899,738	12,549,315	8,260,829	561,278	714,546	483,076
Incentive	16,574,367	21,230,173	16,213,341	864,412	1,111,278	887,381
Injury and Damages (Labor Loading)	3,289,267	3,541,940	3,336,877	196,739	207,864	207,990
Insurance	44,126,315	44,905,601	49,112,043	2,643,628	2,655,821	3,056,059
Other Compensation	4,748,793	5,693,644	2,845,442	237,789	289,762	146,939
Overtime	48,965,486	47,769,119	48,667,981	2,803,027	2,442,415	2,657,482
Payroll Taxes	30,039,123	30,506,289	30,586,935	1,766,650	1,810,372	1,883,093
Pension	24,614,362	39,701,436	42,064,601	1,452,943	2,363,468	2,625,552
Performance Share Plan	3,070,093	(1,325,845)	1,717,919	181,505	(78,623)	104,017
Premium Time	7,101,807	7,126,865	7,412,643	349,425	353,431	386,912
Restricted Stock Units	7,144,916	5,031,062	7,139,131	402,216	278,990	413,789
Welfare Fund	10,734,531	9,661,925	7,879,377	503,518	454,167	378,541
Grand Total	519,081,963	539,293,825	543,689,490	28,751,124	29,167,494	31,029,447

<sup>1</sup> Net of Interchange

Rate Case Adjustments Affecting Labor  
Long Term Incentives

- Non Public Document – Contains Trade Secret Data  
 Public Document – Trade Secret Data Excised  
 Public Document

Xcel Energy

Docket No.: PU-12-813

Response To: North Dakota Public Information NDPS-1-018  
Service Commission Request No.

Requestor: Michael Diller and Sara Cardwell

Date Received: February 26, 2013

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Question:

Please prepare a spreadsheet that replicates workpaper A27-3 which shows the calculation of the Base Incentive amount that would adhere to the 15% requirement for ALL employees including nuclear.

Response:

Please see Attachment A to this response for a replica of workpaper A27-3 updated with a limit on incentive at 15 percent of individual employee base pay.

As discussed on p. 4 of the Compliance Matrix attached to the testimony of Company witness Ms. Laura McCarten, the Company agreed to a 15 percent limitation on recovery of annual incentive plan (AIP) compensation for purposes of settlement in the 2007 electric rate case (PU-07-776). Although the Company filed a settlement in the intervening rate case (PU-10-657) that provides no specific limitation on AIP recovery, the Company adhered to the 15 percent limitation in calculating interim rates in the PU-12-813 application, so the costs above the 15 percent level are not being collected in interim rates. The settlement stated:

For purposes of determining the overall revenue requirement, the Parties agree to a reduction in the cap on incentive compensation from the Company's proposed level of 25 percent to 15 percent of base salary. Accordingly, costs associated with the incentive compensation of the employee's total compensation is capped at 15 percent of an individual's base salary, and costs for incentive compensation in excess of 15 percent of the employee's base salary will not be included in rates.

The Company did not, however, agree to a permanent 15 percent limitation on recovery of incentive compensation in the 2007 rate case settlement. The 2007 settlement also provided:

It is agreed this Settlement Agreement is a negotiated settlement agreement subject to approval by the Commission. Except for the purpose of setting interim rates and depreciation expenses in the Company's next electric rate case, the Settlement Agreement does not establish any principle or precedent, nor adopt or recommend any specific type or amount of expense or rate base, for this or any future proceeding.

The settlement in the Company's 2011 test year rate case (PU-10-657 et al.) established a settlement revenue requirement but did not include any express adjustment for AIP costs. The Company requested recovery of 2013 test year incentive compensation costs, excluding incentive in excess of 25 percent of individual base pay, in final rates in its Application in this proceeding.

The data request also refers to "ALL employees including nuclear." Workpaper A27-3 limits Annual Incentive Program (AIP) amounts to 25 percent of base pay for all employees, including nuclear. The workpaper has a separate line item to include Nuclear Restricted Stock Units, which are a separate incentive program. As a result, Attachment A provides the requested calculation for all employees, including nuclear.

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Witness: Anne E. Heuer  
Preparer: Thomas E. Kramer / James P. Johnson  
Title: Principal Rate Analyst / Assistant General Counsel  
Department: Revenue Requirements – North / Legal Services  
Telephone: 612-330-5866 / 612-215-4592  
Date: April 22, 2013

Northern States Power Company  
Electric Utility - State of North Dakota

Case No. PU-12-813  
NDPSC Data Request 1-018  
Attachment A - Page 1 of 1

**2013 Budget of Base Incentive budgeted at 100% of Target  
Adjustment Worksheet for Electric Utility  
Budgeted at 100% of target with a 15% Cap**

	2013 Budget Amounts for NSPM	NSPM Electric	Minnesota Electric Jurisdiction	North Dakota Electric Jurisdiction	South Dakota Electric Jurisdiction	Wholesale Electric Jurisdiction
Total Identified in Base Data as Incentive	35,380,890	33,409,607	29,317,270	2,065,433	2,015,895	11,010
Less Other Bonuses/Incentives	(502,882)	(502,882)	(440,096)	(32,782)	(29,728)	(276)
Less All Restricted Stock Units	(7,189,782)	(6,784,678)	(5,946,491)	(425,719)	(411,286)	(1,183)
Less Performance Share Plan	(1,832,980)	(1,698,618)	(1,487,277)	(107,974)	(103,302)	(66)
Less Over 15% Amount	(2,994,772)	(2,813,829)	(2,470,564)	(172,502)	(169,604)	(1,159)
Add Nuclear Restricted Stock Units	1,989,999	1,989,999	1,749,535	119,852	119,434	1,178
Baseline Incentive In Test Year	<u>24,850,473</u>	<u>23,599,599</u>	<u>20,722,378</u>	<u>1,446,308</u>	<u>1,421,409</u>	<u>9,504</u>
Total Adjustment to Incentive Amount in Budget		(9,810,008)	(8,594,892)	(619,125)	(594,486)	(1,505)

Electric Total	P	T	D
	58.810%	10.970%	30.220%
(11,800,007)	(6,939,584)	(1,294,461)	(3,565,962)

### **Incentive Pay Adjustment**

This adjustment is designed to lower to total amount of incentive compensation budgeted and assigned to jurisdictions to levels that the Company is seeking recovery of in the filing.

The Company has various incentive programs as part of the overall compensation package. This adjustment removes certain types of incentive that have been deemed to be shareholder responsibility in past rate proceedings.

**2013 Budget of Base Incentive budgeted at 100% of Target  
Adjustment Worksheet for Electric Utility  
Budgeted at 100% of target**

	2013 Budget Amounts for NSPM	NSPM Electric	Minnesota Electric Jurisdiction	North Dakota Electric Jurisdiction	South Dakota Electric Jurisdiction	Wholesale Electric Jurisdiction
Total Identified in Base Data as Incentive	35,380,890	33,409,607	29,317,270	2,065,433	2,015,895	11,010
Less Other Bonuses/Incentives	(502,882)	(502,882)	(440,096)	(32,782)	(29,728)	(276)
Less All Restricted Stock Units	(7,189,782)	(6,784,678)	(5,946,491)	(425,719)	(411,286)	(1,183)
Less Performance Share Plan	(1,832,980)	(1,698,618)	(1,487,277)	(107,974)	(103,302)	(66)
Less Over 25% Amount	(1,458,073)	(1,356,935)	(1,191,400)	(83,187)	(81,789)	(559)
Add Nuclear Restricted Stock Units	1,989,999	1,989,999	1,749,535	119,852	119,434	1,178
Baseline Incentive In Test Year	<u>26,387,172</u>	<u>25,056,493</u>	<u>22,001,542</u>	<u>1,535,623</u>	<u>1,509,223</u>	<u>10,104</u>
Total Adjustment to Incentive Amount in Budget		<u>(8,353,114)</u>	<u>(7,315,728)</u>	<u>(529,810)</u>	<u>(506,672)</u>	<u>(905)</u>

Electric Total	P	T	D
	58.810%	10.970%	30.220%
(8,353,114)	(4,912,466)	(916,337)	(2,524,311)

**PUBLIC SERVICE COMMISSION OF WISCONSIN**

Application of Northern States Power Company-Wisconsin for  
Authority to Adjust Electric and Natural Gas Rates

4220-UR-117

**FINAL DECISION**

This is the Final Decision concerning the application of Northern States Power Company—Wisconsin, doing business as Xcel Energy (NSPW), for authority to increase Wisconsin retail electric and natural gas rates in 2012.

Final overall rate changes are authorized consisting of a \$12,155,000 annual rate increase for Wisconsin retail electric operations, a 2.14 percent increase, and a \$2,924,000 annual rate increase for Wisconsin retail natural gas operations, a 2.37 percent increase, for the test year ending December 31, 2012, based on a 10.40 percent return on common equity. In addition to these increases, net proceeds from the U.S. Department of Energy (DOE) litigation settlement of \$12,945,000 will be returned to retail electric customers as a one-time bill credit in 2012.

**Introduction**

On June 1, 2011, NSPW filed for authority to increase its Wisconsin retail electric and natural gas rates on January 1, 2012. On June 17, 2011, NSPW revised its application resulting in a request of a \$29,235,000 (5.14 percent) increase for retail electric utility operations and an \$8,034,000 (6.56 percent) increase for retail natural gas utility operations. Proposed rates were based on a 10.75 percent return on common equity (ROE).

Docket 4220-UR-117

increase in base salaries. For bargaining unit employees, the annual increases are typically associated with amounts negotiated in labor contracts. Commission staff's forecasted merit increases for non-union employees reflect current economic conditions and impacts on businesses and small-use customers from recent increases in their utility bills, while still providing utility employees some wage adjustment.

In order to reflect the current economic conditions in Wisconsin, the Commission concludes it is appropriate to incorporate 1.5 percent payroll merit increases in 2011 and 2012 for non-union employees and 2.5 percent payroll merit increases in 2011 and 2012 for union employees under contract in the development of test year payroll expense and related taxes.

#### **Annual Incentive Plan Compensation**

The non-bargaining employee cash compensation includes two components: base salary and the Annual Incentive Plan (AIP). Eligible employees have a targeted annual incentive expressed as a percentage of base salary. Target levels assume 100 percent achievement of individual, business area, and corporate objectives. In order for any AIP payments to occur, Xcel Energy must meet certain financial and operational goals. Commission staff reduced NSPW's 2012 payroll O&M expense by \$2,407,000 to eliminate the costs associated with the AIP. Commission staff also reduced pension and benefits expenses and payroll tax expenses associated with the AIP expenses by \$330,000.

NSPW maintained that the Commission should allow recovery of all AIP costs because it allows the total cash compensation to be competitive with the relevant market, it is a cost savings approach to providing cash compensation, and it is consistent with the standards and best practices of public and private companies in the U.S.

Docket 4220-UR-117

Consistent with the other the large investor-owned utilities in Wisconsin in which the costs associated with incentive pay plans are not included in revenue requirements, and the current economic conditions in Wisconsin, it is appropriate for the Commission to limit the financial impacts on ratepayers and exclude these costs from NSPW's revenue requirements.

#### **Uncollectible Accounts Expense**

Commission staff's estimate of test-year uncollectible accounts expense was derived by multiplying its forecasted sales revenue to residential, commercial and industrial customers at present rates, by an historical percentage of net write-offs to applicable sales revenue.

NSPW opposed the Commission staff's method of forecasting Uncollectible Accounts Expense for two reasons. First, the Commission staff method applies the ratio of net write-offs to revenues at present rates instead of revenues at proposed rates. Second, it relies solely on actual net uncollectible write-offs instead of actual FERC Account 904, Uncollectible Account Expense, to calculate the ratio. Regarding the application of the ratio of net uncollectible write-offs to total revenues at present rates, Commission staff recognized that there is a relationship between revenues and uncollectible accounts expense. However, there are procedural problems with using proposed rates to estimate uncollectible accounts expense. If the forecast of uncollectible accounts expense is based on proposed revenues, the adjustment process would become iterative. In response, NSPW proposed to make the uncollectible accounts expense the last adjustment in the revenue requirement calculations to proposed rates and exclude uncollectible accounts expense from the calculation of final revenue requirement in determining the adjustment. This type of adjustment has not been made in prior NSPW cases or in rate proceedings for other major Wisconsin investor-owned utilities for a number of reasons.

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 Public Document

Xcel Energy

Case No.: PU-12-813

Response To: North Dakota Public Service Commission      Data Request No.      NDPSC-2-019

Requestor: Mike Diller & Sara Cardwell

Date Received: March 8, 2013

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Question:

Pension Expense Increase Question:

With the recent uptick in the market, does the Company's request for additional funding for the pension expenses change and if so by how much?

Response:

Pension expense is only calculated once per year based on December 31 asset balances and assumptions, and as a result any asset returns that exceed expectations in the current year will not be reflected until we update our pension expense projections for 2014.

The updates for 2013, based on the December 31 asset balances and assumptions, are contained in the February 7, 2013 actuarial report. This report shows a slight decrease to 2013 pension expense related to 2012 asset returns exceeding the expected return of 7.50% and to the wage increase assumption being decreased from 4.00% to 3.75%. These decreases were offset by cost increases related to a lowered discount rate assumption, a reduction in the expected return on asset assumption, and unfavorable demographic experience true-ups. These factors led to an increase in North Dakota jurisdiction costs of \$246,393. Any 2013 year-to-date gains that exceed the expected asset return of 7.25% will not be reflected in the pension expense calculation until 2014.

Please see Attachment A for a comparison of the 2013 test year qualified pension expense to the updated 2013 expense resulting from the changes mentioned above.

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Preparer: Todd Degrugillier  
Title: Mgr, Employee Tax & Accounting  
Department: Payroll and Benefits Accounting  
Telephone: 612-330-6557  
Date: April 10, 2013

**Northern States Power Company**

**Case No PU-12-813  
Data Request NDPSC 2-19  
Attachment A, Page 1 of 1**

**2013 Test Year Qualified Pension Updated**

	<b>2013 Test Year</b>	<b>2013 Test Year Updated with 2-7-13 Actuarial Report</b>	<b>Change Amount</b>
NSPM Total Cost Amount	\$34,032,000	\$38,501,000	\$4,469,000
Percent to NSPM Electric O&M	60.2%	60.2%	
Amount to NSPM Electric O&M	\$20,476,138	\$23,165,015	\$2,688,877
Nuclear Total Cost Amount	\$2,823,000	\$3,205,000	\$382,000
Percent to NSPM Electric O&M	93.6%	93.6%	
Amount to NSPM Electric O&M	\$2,643,108	\$3,000,765	\$357,658
XES Total Cost Amount	\$29,971,000	\$33,394,000	\$3,423,000
Percent to NSPM Electric O&M	29.0%	29.0%	
Amount to NSPM Electric O&M	\$8,686,040	\$9,678,076	\$992,036
Amounts from affiliates	\$2,492	\$2,492	-
Total NSPM Electric O&M	\$31,807,779	\$35,846,349	\$4,038,571
Percent to North Dakota Jurisdiction	6.101%	6.101%	
Total NSPM Electric O&M in ND Jurisdiction	\$1,940,593	\$2,186,986	\$246,393

**Assumptions**

Discount Rate XEPP Plan	5.00%	4.03%
Discount Rate Aggregate Cost	7.50%	7.25%
Salary Scale	4.00%	3.75%
Expected Return on Assets	7.50%	7.25%

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 Public Document

Xcel Energy

Docket No.: PU-12-813

Response To: North Dakota Public Service Commission      Data Request No.      NDPSC-1-001

Requestor: Michael Diller and Sara Cardwell

Date Received: February 26, 2013

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Question:

As mentioned on page 14 of McCarten's testimony, what are the Company's proposals for smoothing the impact of the increased pension costs?

Response:

Xcel Energy proposes two normalization methods for consideration:

- Extend the NSPM Plan amortization period for unrecognized pension costs. This change is allowed under the Aggregate Cost Method (ACM) that is used to determine NSPM Plan costs.
- Cap the Xcel Energy Service Company (XES) pension expense at the 2011 level of \$373,615 and defer the difference in excess of this level to future years.

Commission approval of either method would moderate the impact of these costs for our customers but would result in delayed recovery for the Company. Thus, appropriate ratemaking treatment would include a return on the unamortized balance. Each method is discussed below, followed by a comparison of the 2013-2017 pension cost amounts determined under these two methods to the Company's pension cost for 2013-2017.

Extending the NSPM Plan Amortization Period

Costs for the NSPM Plan are determined under the ACM, which allows a change in the amortization period. The current amortization method was adopted prior to 1987 and is based on a pension funding method and guidelines provided by the Internal Revenue Service. It was also used as the basis for expense recognition by NSPM. When FAS 87 was implemented in 1987, the method did not comply. However, an

amortization method that does not comply with FAS 87 may still be used (as a permitted exception under SFAS 71) *if* it is recognized for regulatory purposes. Since we were able to obtain Commission approval for ratemaking purposes, we were able to continue using this method after the implementation of FAS 87 in 1987. Our proposed change would require moving from the current “percent of compensation” based amortization period of approximately 10 years to a 20-year amortization basis. The 20-year amortization basis would remain in effect from year to year and would not be recalculated annually.

Again, since we can use an amortization method that does not comply with FAS 87 only if it is recognized for regulatory purposes, the 20-year amortization period requires acceptance by the Commission for ratemaking purposes. The impact of this change for the 2013 test year and the four-year forecast are shown in the table below.

**Impact of Extending ACM Amortization to 20 Years (\$'s)**

	<b>2013</b>	<b>2014</b>	<b>2015</b>	<b>2016</b>	<b>2017</b>
NSPM Electric O&M North Dakota	(446,854)	(361,226)	(289,466)	(233,989)	(173,670)

Over a longer time horizon, pension expense must ultimately equal actual cash funding. This is true under the current method as well as under the alternative method. Thus, over the full 20-year period, the total costs recovered would remain the same as it would over the current 10-year period.

This approach is not an option for recognizing expenses charged from XES under FAS 87. Since XES was formed *after* the adoption of FAS 87 and is not accountable to a single ratemaking jurisdiction, it is required by FERC to recognize costs under FAS 87. FAS 87 has strict requirements for how pension expense assumptions are set. Among these requirements is that gains and losses in the XES Plan must be recognized over a period not to exceed the average expected remaining years of service for active employees.

Capping the XES Plan Pension Expense

Although the amortization period of gains and losses cannot be extended for the XES Plan consistent with FERC requirements, the Commission has the ability to allow deferral of costs to a later period through a rate Order. In this case, XES pension expense above a pre-established threshold could be deferred and recognized in a future period either when costs drop below the pre-established threshold or through a separate expense recognition mechanism, such as a pre-established amortization period.

XES Plan pension expenses in the 2013 test year would be recovered at 2011 levels, and the XES Plan pension expenses above 2011 expense levels would be deferred and recovered in future years. The table below shows the projected annual and cumulative expense impact of capping the XES expense amounts at the 2011 level of \$373,615 for the 2013 Test Year and the four year forecast.

**Impact From Capping XES at 2011 Level (\$'s)**

	<b>2013</b>	<b>2014</b>	<b>2015</b>	<b>2016</b>	<b>2017</b>
NSPM Electric O&M North Dakota (Per Year)	(156,472)	(53,111)	8,184	63,827	116,669
NSPM Electric O&M North Dakota (Cumulative)	(156,472)	(209,583)	(201,399)	(137,572)	(20,904)

The projections assume no incremental gains or losses which would either accelerate or further delay the recognition of deferred costs.

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Preparer: Todd M. Degrugillier  
Title: Manager, Employee Tax and Accounting  
Department: Payroll and Benefits Accounting  
Telephone: 612-330-6557  
Date: March 19, 2013

Northern States Power Company  
Electric Utility - State of North Dakota

Case No. PU-12-813

**2013 Test Year Medical and Pharmacy Claims Adjustment**

	<b>O&amp;M Expense</b>		
	<b>Medical and Pharmacy Claims</b>		
	<b>NSPM</b>	<b>XES</b>	<b>Total</b>
2012 Total Cost Forecast (as of 2/28/2013)	34,979,788	25,762,347	
2013 8% Inflation Assumption	2,798,383	2,060,988	
2013 Total Cost Forecast	37,778,171	27,823,334	
Percent to NSPM O&M Electric	69.1%	29.0%	
Amount to NSPM O&M Electric	26,115,066	8,063,595	
Percent to State of ND Jurisdiction	6.1%	6.1%	
2013 Revised Amount to State of ND Jurisdiction	1,593,203	491,936	2,085,139
2013 Test Year as Filed			2,334,886
Proposed O&M Adjustment			<b>(249,747)</b>

**Xcel Energy**  
**Annual Revenue Requirement**  
**Summary of Projects no longer in Test Year**  
**2013 Test Year North Dakota Electric Rate Case**

**Case No. PU-12-813**  
**Page 1 of 2**

(000's)	TOTAL	West Creek Sub to Scott County Transmission	MNGP Data Acq System Production	Scott County Sut Transmission	Pipestone to Tracy Line Transmission	PI EPU Production	St. Cloud Loop Transmission	Chisago 2nd Transformer Transmission
	Total Company	Total Company	Total Company	Total Company	Total Company	Total Company	Total Company	Total Company
Plant Investment	\$ (11,310)	\$ (2,630)	\$ (1,000)	\$ (1,773)	\$ (657)	\$ -	\$ (5,249)	\$ -
Depreciation Reserve	40	(2)	(2)	(1)	(1)	-	44	2
CWIP	(97,402)	2,638	1,003	1,778	-	(99,971)	(2,722)	(128)
Accumulated Deferred Taxes	1,012	(55)	(109)	(37)	(15)	1,840	(612)	0
	(109,764)	64	114	44	(642)	(101,811)	(7,403)	(131)
Average Rate Base	(109,764)	64	114	44	(642)	(101,811)	(7,403)	(131)
Debt Return	(3,106)	2	3	1	(18)	(2,881)	(209)	(4)
Equity Return	(6,004)	4	6	2	(35)	(5,569)	(405)	(7)
Current Income Tax Requirement	(589)	94	207	65	6	(2,006)	1,047	(1)
Book Depreciation	(129)	(4)	(4)	(3)	(1)	-	(117)	-
Annual Deferred Tax	(667)	(109)	(228)	(75)	(30)	987	(1,211)	(1)
ITC Flow Thru	-	-	-	-	-	-	-	-
Tax Depreciation & Removal Expense	(4,262)	(266)	(564)	(182)	(65)	-	(3,181)	(4)
AFUDC Expenditure	(6,211)	15	6	10	(41)	(5,954)	(240)	(6)
Remove AFUDC	6,211	(15)	(6)	(10)	41	5,954	240	6
Avoided Tax Interest	(4,464)	11	-	7	(30)	(4,272)	(176)	(4)
Property Taxes	(6)	-	-	-	-	-	(6)	-
<b>Total Revenue Requirements</b>	<b>\$ (10,501)</b>	<b>\$ (14)</b>	<b>\$ (16)</b>	<b>\$ (10)</b>	<b>\$ (78)</b>	<b>\$ (9,470)</b>	<b>\$ (901)</b>	<b>\$ (13)</b>

Revenue Requirement Exhibits  
Case No. PUC-12-813  
Page 170 of 233

Xcel Energy  
 Annual Revenue Requirement  
 Summary of Projects no longer in Test Year  
 2013 Test Year North Dakota Electric Rate Case

Case No. PU-12-813  
 Page 2 of 2

(000's)	TOTAL	West Creek Sub to Scott County Transmission	MNGP Data Acq System Production	Scott County Sut Transmission	Pipestone to Tracy Line Transmission	PI EPU Production	St. Cloud Loop Transmission	Chisago 2nd Transformer Transmission
	ND Jurisdiction	ND Jurisdiction	ND Jurisdiction	ND Jurisdiction	ND Jurisdiction	ND Jurisdiction	ND Jurisdiction	ND Jurisdiction
Plant Investment	\$ (579)	\$ (135)	\$ (51)	\$ (91)	\$ (34)	\$ -	\$ (269)	\$ -
Depreciation Reserve	2	(0)	(0)	(0)	(0)	-	2	-
CWIP	-	-	-	-	-	-	-	-
Accumulated Deferred Taxes	51	(3)	(6)	(2)	(1)	94	(31)	-
	(631)	(132)	(46)	(89)	(33)	(94)	(239)	-
Average Rate Base	(631)	(132)	(46)	(89)	(33)	(94)	(239)	-
Debt Return	(18)	(4)	(1)	(3)	(1)	(3)	(7)	-
Equity Return	(35)	(7)	(2)	(5)	(2)	(5)	(13)	-
Current Income Tax Requirement	(53)	1	9	1	(1)	(108)	45	-
Book Depreciation	(7)	(0)	(0)	(0)	(0)	-	(6)	-
Annual Deferred Tax	(34)	(6)	(12)	(4)	(2)	50	(62)	-
ITC Flow Thru	-	-	-	-	-	-	-	-
Tax Depreciation & Removal Expense	(218)	(14)	(29)	(9)	(3)	-	(163)	-
AFUDC Expenditure	-	-	-	-	-	-	-	-
Remove AFUDC	-	-	-	-	-	-	-	-
Avoided Tax Interest	(228)	1	-	0	(2)	(219)	(9)	-
Property Taxes	(0)	-	-	-	-	-	(0)	-
Total Revenue Requirements	\$ (147)	\$ (16)	\$ (7)	\$ (11)	\$ (5)	\$ (65)	\$ (43)	\$ -

### North Dakota DSM Amortization

The purpose of this adjustment is to record the annual amortization of the certain ND DSM related costs. The ND Commission allowed the Company to defer certain DSM related costs incurred in 2008 and 2009 to be amortized in rates in the next rate case. In Docket PUC10-657 the Company was authorized to amortize these costs over three years. This adjustment is taking the unamortized balance as of 12/31/12 and spreading it over a new three year period 2013 - 2015.

ND DSM Amortization  
 Per CIP Budgeted W/P

Unamortized Bal Dec 2012      168,486

Amort over 36 Months

<u>FY 2013</u>	<u>Mo Amort</u>
Jan	4,680
Feb	4,680
Mar	4,680
Apr	4,680
May	4,680
Jun	4,680
Jul	4,680
Aug	4,680
Sep	4,680
Oct	4,680
Nov	4,680
Dec	4,680

2013 Total ND DSM Amort

56,162
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Xcel Energy

Docket No.: PU-12-813

Response To: North Dakota Public Information NDPS-1-015  
Service Commission Request No.

Requestor: Michael Diller and Sara Cardwell SUPPLEMENT

Date Received: February 26, 2013

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Question:

In reference to page 76 of Heuer's testimony, if the Company is allowed to pass all the costs of processing a rate case onto customers, what assurances can the Company provide that indicates the Company controls these expenses? For the 2013 case, the Company proposes to spend \$153,000 on consultants and \$300,000 on outside legal fees. Please provide a listing of all expenses that comprise the \$562,000 from the 2012 rate increase case (PU-11-55), additional detail on each contract included in the 2013 forecast expenses and the Company's policy on how it controls rate case expenditures.

Response:

Please see Attachment A to this response for a summary tabulation of all expenses charged to the deferred rate case work order established for the 2010 North Dakota Electric Rate Case (PU-10-657 and PU-11-55). Actual rate case expenses for the 2010 case were \$663,127, exceeding the \$562,000 estimate by \$101,127. Attachment B to this response provides the workpaper from the 2010 case record providing the test year estimate of \$562,000 in rate case expenses. Ratepayers were not charged for amounts incurred above the \$562,000 included in the 2011 test year.

Expert consultants on Return on Equity (ROE), legal services and regulatory administration are the largest variable rate case costs. These services are procured specifically for each individual rate case. In addition, the test year includes an estimate of costs to be billed to the Company by the Commission and Administrative Law Judge associated with the case (\$125,000). There are also administrative costs such as bill inserts, printing, copying, and postage (\$40,000). Finally, in this case the Company engaged a former employee to consult on revenue requirements issues (\$35,000). (We note that in the 2011 test year case, the costs billed were double the estimated amounts.) The Company relies on both in-house counsel and external counsel to provide the appropriate legal support on the myriad of complex legal issues related to utility

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operations. Likewise, while the Company has in-house financial market expertise, it is common utility practice to retain an outside expert to provide testimony based on independent market research and insight. Such services were arranged for the 2013 North Dakota rate case and include Concentric Energy Associates (ROE and Capital Structure expert witness) and Moss and Barnett (outside legal resource). Because of the number of discovery requests from Staff's consultants, and the addition of the Prairie Rose Wind Power Purchase Agreement recovery issue to this rate case, the Company also engaged Briggs and Morgan as a second outside legal resource.

In the case of Concentric Energy Associates, there is a fixed amount charged for work done to prepare the initial testimony filed with the Company's application, **[TRADE SECRET BEGINS                      TRADE SECRET ENDS]**, and an estimate for further work that may be necessary through the various remaining stages of the rate proceeding (including discovery responses, rebuttal testimony, and participation at the hearing) **[TRADE SECRET BEGINS                      TRADE SECRET ENDS]**.

The Company engaged the legal services of Moss and Barnett by letter agreement, estimating the 2012 fees of **[TRADE SECRET BEGINS                      TRADE SECRET ENDS]** during the period of preparation of all rate case filing materials. Further legal services are performed during the pendency of this rate case – for discovery response support, rebuttal testimony development, the hearing, post hearing briefs – at hourly rates on an as-needed basis. These costs were not included in the 2012 fee estimate. As noted, we also retained the services of Briggs and Morgan to provide legal assistance, particularly with discovery and supplemental testimony on the Prairie Rose Wind PPA issue. The estimated 2013 fees associated with Briggs' work was **[TRADE SECRET BEGINS                      TRADE SECRET ENDS]**. The estimated Briggs amount did not assume the level of discovery being experienced to date. Given the level of discovery, the Company expects the initial budget to be increased substantially.

In light of past experience, we believe the combination of the ROE and outside legal estimates included in the test year are reasonable, even if the actual cost levels for the two components may vary from the estimates.

With respect to cost control, we have recently begun to include in our ROE vendor contracts pricing based on 'not to exceed' or fixed-price terms where feasible. Due to the unpredictability of the extent to which services would be needed to support discovery and further testimony in a particular proceeding, these types of contracting terms are not used to cover the entire scope of work that may be expected.

The Xcel Energy operating companies have been very active in rate case work in our eight retail jurisdictions over the last three to four years with approximately eight to nine cases in progress each year. There are three different firms we typically use to

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provide our ROE testimony, and we periodically ask for bids to do ROE work. Most recently, we competitively bid the ROE work for two cases filed in Texas and New Mexico at the end of 2012. Based on the frequency with which we hire ROE expertise, we are very familiar with the market for the rates and amounts being proposed to us and select those that are competitively priced, particularly where they offer the advantage of having previously completed work for that jurisdiction and can provide continuity.

We did not competitively bid the ROE work for this case but instead elected to continue with the expertise of the witness who had most recently prepared testimony on the subject for the North Dakota jurisdiction. This decision was made based on the quality of work and comparable pricing based on our experience in this and other jurisdictions.

For legal resources, we actively manage work assignments between internal and external resources, based on expertise, workload, and cost. As internal rate case experience increases, in some instances, we are able to rely less on outside counsel. However, knowledge of the Company and its prior rate cases (and rate cases in other jurisdictions) by outside counsel provides significant efficiencies. Involvement of multiple firms also assists in keeping costs competitively priced. The selected firms are subject to the Xcel Energy Outside Counsel Guidelines, which require firms to use the lowest-cost appropriate resource for the work being performed (e.g., an associate rather than a partner, where appropriate).

The Company has a strong incentive to manage rate case expenses within its test year budget, as any actual costs which exceed the test year amount will not be recoverable in rates. Rate case expenses are tracked by a unique work order opened for each specific rate case. Expenses related to that case are charged to the work order and tracked for recovery in the relevant jurisdiction. Invoices are reviewed carefully by the Law, Regulatory, and Accounting departments each month for accuracy and appropriateness to the work performed and must be approved prior to payment.

**SUPPLEMENT:**

At the request of Commission staff's consultants, the information in Attachment C to this supplemental response provides actual expenses charged to the deferred rate case work order and paid through June 21, 2013 in the same form as Exhibit\_\_\_\_(AEH-1), Schedule 19. Invoices for professional consulting and legal resources lag the period for which work is performed, and consequently there are likely additional charges pending or to be invoiced for applicable work done to date. Please note that Attachments A and B to the original response have not been revised or supplemented but are included here.

**PUBLIC DOCUMENT**  
**TRADE SECRET INFORMATION EXCISED**

Witness: Anne E. Heuer  
Preparer: Debra J. Paulson  
Title: Manager, Rate Cases  
Department: NSPM Regulatory  
Telephone: 612-330-7571  
Date: May 9, 2013

**SUPPLEMENTED:** June 26, 2013

Northern States Power Company  
Electric Company - State of North Dakota

Case No. PU-12-813  
NDPSC Data Request 1-015 PUBLIC Supplement  
Attachment A - Page 1 of 1

**North Dakota Electric Rate Case Expenses  
Year Ended 12/31/2011**

<b>DESCRIPTION</b>	<b>2011 Rate Case Estimate</b>	<b>Actual</b>	<b>Difference</b>
Consulting	\$ 130,000	\$ 232,309	\$ 102,309
Outside Legal Fees	275,000	152,036	(122,964)
State Agency Fees	125,000	251,803	126,803
Administrative Costs	31,400	26,980	(4,420)
	<b>\$ 561,400</b>	<b>\$ 663,129</b>	<b>\$ 101,729</b>

Northern States Power Company  
Electric Utility - State of North Dakota

Case No. PU-12-813  
NDPSC Data Request 1-015 PUBLIC Supplement  
Attachment B - Page 1 of 1

NORTHERN STATES POWER COMPANY				
2011 Requested Expenses				
RATE CASE AMORTIZATION				
FERC	Business Unit Description		Monthly	State of ND Annual
928	NSPM E Regulatory Expense-ND			
	Total Rate Case costs to amortize	561,400		
	24 month amortization		23,392	280,700

**Electric RATE CASE EXPENSES**  
Year Ended 12/31/2011

**DESCRIPTION**

Consulting	130,000	
Itron & Christensen Assoc	5,000	Interruptible Rates Study
Robinson	35,000	Robinson
Concentric	90,000	Return On Equity
Towers Watson		Compensation Study
Outside Legal Fees	275,000	
Moss & Barnett		
State Agency Fees	125,000	
Administrative Costs	31,400	
Inserts/Notices	6,000	Ads and Inserts
Postage	600	Postage and Messenger Service
Rentals - Hearings	16,800	Employee Expenses
Copies	8,000	
	561,400	

Northern States Power Company  
Electric Utility - State of North Dakota

Case No. PU-12-813  
NDPSC Data Request 1-015 PUBLIC Supplement  
Attachment C - Page 1 of 1

<b><u>ND Electric Rate Case - Actual Expenses Paid Through June 21, 2013</u></b>		<b><u>2013 North Dakota Jurisdiction</u></b>
Consulting Fees		\$ 60,418
Alliance Consulting	7,448	
Robinson	13,575	
Concentric	39,395	
Outside Legal Fees		83,478
State Agency Fees and Administrative Law Judge		125,380
Administrative Costs (transcripts, admin)		13,464
<b>TOTAL</b>		<b><u><u>\$282,740</u></u></b>

### **Current Year Rate Case Amortization Adjustment**

**The purpose of this adjustment is to record the amortization of the estimated Rate Case expenses for the current rate filings under review for the North Dakota Jurisdiction.**

**NORTHERN STATES POWER COMPANY  
SOUTH DAKOTA  
RATE CASE EXPENSES  
For 2012 Rate Case Filing**

<b>DESCRIPTION</b>	<b>12-046</b>	
<b>DESCRIPTION</b>	<b>Estimated Costs</b>	
Consulting		
Concentric		90,000
Outside Legal Fees		175,000
Moss & Barnett		
State Agency Fees		125,000
State		
Administrative Costs		
Court Reporter		
Inserts/Notices		5,000
Postage/Delivery/Copies		12,500
Rentals - Hearings		500
Prior Residual Costs from EL11-019		210,000
Consulting	50,000	
Legal	80,000	
SD Commission	65,000	
Misc	15,000	
		618,000
	Amort 3 years	206,000

**NORTHERN STATES POWER COMPANY**  
**2013 Requested Expenses**  
**North Dakota Rate Case Amortization**

FERC	Business Unit Description		Monthly	State of ND Annual
928	NSPM E Regulatory Expense-ND			
	Estimated Rate Case Costs	618,000		
	36 month amortization		17,167	206,000

**Electric RATE CASE EXPENSES**  
**Year Ended 12/31/2013**

**DESCRIPTION**

Consulting	153,000	
Itron & Christensen Assoc	10,000	
Robinson	35,000	
Concentric	100,000	
Towers Watson	8,000	
Outside Legal Fees	300,000	
Moss & Barnett		
State Agency Fees	125,000	
Directs / ALJ		
Intervenors		
Administrative Costs	40,000	
Inserts/Notices	8,000	Ads and Inserts
Postage	2,000	Postage and Messenger Service
Rentals - Hearings	20,000	
Materials	10,000	
Unamortized Balance from Docket 10-657		
Unamortized Balance 12-31-2012	-	
	<b>618,000</b>	

### Prior Year Rate Case Amortization Adjustment

The purpose of this adjustment is to record the amortization of the Rate Case expenses incurred for the rate filings previously authorized for the North Dakota and South Dakota Jurisdiction.

ND Elec 2010 Case  
JDE 10.248417.2010  
JDE Amort Exp Acct 624011.752800

Prior Approved Mo Amort 15,611 Amortized over 36 Months

Approved Level in Order 562,000

Dec 2011 Balance 399,756

Dec 2012 Balance 212,423

Month	Amort	Balance	Notes
Jan 13	5,901	206,522	Amort over 36 months
Feb 13	5,901	200,621	
Mar 13	5,901	194,721	
Apr 13	5,901	188,820	
May 13	5,901	182,919	
Jun 13	5,901	177,019	
Jul 13	5,901	171,118	
Aug 13	5,901	165,218	
Sep 13	5,901	159,317	
Oct 13	5,901	153,416	
Nov 13	5,901	147,516	
Dec 13	5,901	141,615	

Jan 14	5,901	135,714
Feb 14	5,901	129,814
Mar 14	5,901	123,913
Apr 14	5,901	118,013
May 14	5,901	112,112
Jun 14	5,901	106,211
Jul 14	5,901	100,311
Aug 14	5,901	94,410
Sep 14	5,901	88,509
Oct 14	5,901	82,609
Nov 14	5,901	76,708
Dec 14	5,901	70,808

Jan 15	5,901	64,907
Feb 15	5,901	59,006
Mar 15	5,901	53,106
Apr 15	5,901	47,205
May 15	5,901	41,304
Jun 15	5,901	35,404
Jul 15	5,901	29,503
Aug 15	5,901	23,603
Sep 15	5,901	17,702
Oct 15	5,901	11,801
Nov 15	5,901	5,901
Dec 15	5,901	0

## North Dakota PFS Amortization

The Company spent approximately \$23 million to obtain an NRC license for Private Fuel Storage, a private independent spent fuel storage installation within the Goshute Indian tribal land in Utah. Of the \$23 million, \$1.14 million is assigned to the State of North Dakota.

In the 2008 rate case, the Commission approved a six-year amortization of the \$1.14 million beginning in 2008.

This adjustment takes the remaining un-amortized balance as of 12/31/2012 and amortizes it over three years beginning in 2013.

**2013 North Dakota Rate Case  
248250 Private Fuel Storage North Dakota**

		No Dak Asset 10.248250.1000
Amount Authorised last case State of ND Regulatory Amortization over 72 Months	15,833	1,140,000
Balance 12/31/2009		<u>778,095</u>
Balance 12/31/2010		<u>588,095</u>
Balance 12/31/2011		<u>398,095</u>
Balance 12/31/2012		<u>208,095</u>
Jan 13	5,780	202,315
Feb 13	5,780	196,534
Mar 13	5,780	190,754
Apr 13	5,780	184,974
May 13	5,780	179,193
Jun 13	5,780	173,413
Jul 13	5,780	167,632
Aug 13	5,780	161,852
Sep 13	5,780	156,071
Oct 13	5,780	150,291
Nov 13	5,780	144,511
Dec 13	5,780	138,730
Jan 14	5,780	132,950
Feb 14	5,780	127,169
Mar 14	5,780	121,389
Apr 14	5,780	115,609
May 14	5,780	109,828
Jun 14	5,780	104,048
Jul 14	5,780	98,267
Aug 14	5,780	92,487
Sep 14	5,780	86,706
Oct 14	5,780	80,926
Nov 14	5,780	75,146
Dec 14	5,780	69,365
Jan 15	5,780	63,585
Feb 15	5,780	57,804
Mar 15	5,780	52,024
Apr 15	5,780	46,243
May 15	5,780	40,463
Jun 15	5,780	34,683
Jul 15	5,780	28,902
Aug 15	5,780	23,122
Sep 15	5,780	17,341
Oct 15	5,780	11,561
Nov 15	5,780	5,780
Dec 15	5,780	(0)

2013 Amortization  
69,365

## North Dakota Emission Allowances Amortization

The Company has placed the ND electric proceeds from emission allowance sales into FERC account 254, Other Regulatory Liabilities, pending a determination of the ratemaking treatment of the gains from such transactions.

**2013 ND Electric Rate Case  
ND EPA Emission Credit Auction Proceeds**

**JDE Acct  
10.424490**

	Amortize over 36 Month: Balance 12/31/2010	<u>(260,197.69)</u>
	Balance 12/31/2011	<u>(185,217.29)</u>
Jan 12	7,227.71	(177,989.58)
Feb 12	7,227.71	(170,761.87)
Mar 12	7,227.71	(163,534.16)
Apr 12	7,190.28	(156,343.88)
May 12	7,227.71	(149,116.17)
Jun 12	7,227.71	(141,888.46)
Jul 12	7,227.71	(134,660.75)
Aug 12	7,227.71	(127,433.04)
Sep 12	7,227.71	(120,205.33)
Oct 12	7,227.71	(112,977.62)
Nov 12	7,227.71	(105,749.91)
Dec 12	7,227.71	(98,522.20)
	Balance 12/31/2012	<u>(98,522.20)</u>

For ND Rate Case request amortization over 36 months

Jan 13	2,736.73	(95,785.47)
Feb 13	2,736.73	(93,048.74)
Mar 13	2,736.73	(90,312.02)
Apr 13	2,736.73	(87,575.29)
May 13	2,736.73	(84,838.56)
Jun 13	2,736.73	(82,101.83)
Jul 13	2,736.73	(79,365.11)
Aug 13	2,736.73	(76,628.38)
Sep 13	2,736.73	(73,891.65)
Oct 13	2,736.73	(71,154.92)
Nov 13	2,736.73	(68,418.19)
Dec 13	2,736.73	(65,681.47)
Jan 14	2,736.73	(62,944.74)
Feb 14	2,736.73	(60,208.01)
Mar 14	2,736.73	(57,471.28)
Apr 14	2,736.73	(54,734.56)
May 14	2,736.73	(51,997.83)
Jun 14	2,736.73	(49,261.10)
Jul 14	2,736.73	(46,524.37)
Aug 14	2,736.73	(43,787.64)
Sep 14	2,736.73	(41,050.92)
Oct 14	2,736.73	(38,314.19)
Nov 14	2,736.73	(35,577.46)
Dec 14	2,736.73	(32,840.73)
Jan 15	2,736.73	(30,104.01)
Feb 15	2,736.73	(27,367.28)
Mar 15	2,736.73	(24,630.55)
Apr 15	2,736.73	(21,893.82)
May 15	2,736.73	(19,157.09)
Jun 15	2,736.73	(16,420.37)
Jul 15	2,736.73	(13,683.64)
Aug 15	2,736.73	(10,946.91)
Sep 15	2,736.73	(8,210.18)
Oct 15	2,736.73	(5,473.46)
Nov 15	2,736.73	(2,736.73)
Dec 15	2,736.73	0.00

ND Emission  
(32,840.73)

Amount in CFM revenue that must be removed.  
\$86,733 (\$7,227.71 \* 12)

- Non Public Document – Contains Trade Secret Data  
 Public Document – Trade Secret Data Excised  
 Public Document

Xcel Energy

Case No.: PU-12-813

**SUPPLEMENT**

Response To: North Dakota Public  
Service Commission

Data Request No. NDPSC-5-056

Requestor: Snavelly King

Date Received: March 29, 2013

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Question:

Witness: Anne E. Heuer-Revenue Requirement (Exhibit AEH-1)

Please refer to Exhibit (AEH-1) Schedule 8, page 4 of 6, Income Tax Summary, specifically Property Taxes:

- a) Please list all property owned by NSPM and the property taxes associated with each unit of property. Please provide the information by year for 2010, 2011, 2012 and, if available, 2013. Please also provide an allocation of the property to the respective jurisdictional operations.
- b) List all refunds or abatements associated for each unit of property for the same time period as provided in part a.
- c) Provide all correspondence associated with the calculation of the property tax rate from all taxing authorities.

Response:

The Company respectfully objects to this request because property taxes are not determined or assessed for each unit of property and it would be unduly burdensome to provide information for individual units.

The Company is preparing summary information regarding NSPM's total property tax assessed for 2010, 2011, 2012 and 2013 and will supplement this response.

**Supplement:**

Property taxes are not shown on the Income Tax Summary in Exhibit (AEH-1) Schedule 8, page 4 of 6. We presume the reference should be the Income Statement Summary on page 3 of 6 in this exhibit.

Generally speaking, the NSPM system is valued by each state's Department of Revenue ("DOR") as a single unit, except for land and certain buildings which are locally assessed by taxing jurisdictions. The NSPM system unit value is allocated to each state based calculations set forth by each states' DOR.. Each DOR then apportions the Company's state unit value to each local taxing jurisdiction. The local taxing jurisdictions combine the apportioned unit value with locally assessed property to arrive at the total value that is subject to property tax. The local jurisdictions do not report back to the Company the portion of the total value attributable to state assessed property and the portion assessed locally.

Attachment A shows property tax amounts for 2010, 2011, 2012, the 2013 test year forecast, and a 2013 update, respectively (net of Interchange Agreement billings to NSPW). The updated 2013 forecast reflects the increase in 2012 local effective tax rates in Minnesota (based on the Minnesota Truth in Taxation notices received by the Company in December 2012) and to account for an increase in the estimated 2013 local property tax rates. Only Minnesota property tax changes were reflected in the forecast update as we do not currently expect material changes in North Dakota and South Dakota property taxes.

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Preparer: Leanna Chapman /James P. Johnson / Shari Cardille  
Title: Consultant, Tax Reporting/Asst. General Counsel/Principal Rate Analyst  
Department: Tax Services /General Counsel / Revenue Requirements North  
Telephone: 612-330-5622 /612-215-4592 /612-330-1974  
Date: April 12, 2013           **Supplemented:** May 15, 2013

Northern States Power Company- Minnesota  
2010 Property Taxes Accrued for 2010

Case No. PU-12-813  
Data Request NDPSC-5-056  
Attachment A - Page 1 of 5

	Property Taxes Paid (by Source State)				Jurisdictional Allocation of Property Tax Expense <sup>1</sup>				
	2010	2010	2010	2010	2010	2010	2010	2010	2010
	Minn	No Dak	So Dak	TOTAL	Minn	No Dak	So Dak	Wholesale	TOTAL
<b>Electric</b>									
Production	\$43,152,502	\$0	\$896,369	\$44,048,871	\$32,415,416	\$2,055,091	\$2,081,796	\$311,143	\$36,843,445
Transmission	\$24,002,607	\$410,286	\$963,946	\$25,376,838	\$18,674,730	\$1,183,951	\$1,187,814	\$179,251	\$21,225,746
Distribution	\$41,261,541	\$1,612,753	\$1,561,363	\$44,435,657	\$41,261,541	\$1,612,753	\$1,561,363	\$0	\$44,435,657
Common	\$912,800	\$75,829	\$0	\$988,629	\$890,705	\$46,794	\$46,400	\$4,730	\$988,629
<b>Total Electric</b>	<b>\$109,329,450</b>	<b>\$2,098,868</b>	<b>\$3,421,678</b>	<b>\$114,849,996</b>	<b>\$93,242,391</b>	<b>\$4,898,588</b>	<b>\$4,857,374</b>	<b>\$495,124</b>	<b>\$103,493,477</b>
<b>Gas</b>									
Production	\$1,214,617	\$15,237	\$0	\$1,230,054	\$1,101,593	\$128,461	\$0	\$0	\$1,230,054
Transmission	\$896,974	\$32,208	\$0	\$929,182	\$896,974	\$32,208	\$0	\$0	\$929,182
Distribution	\$11,901,589	\$928,071	\$0	\$12,829,660	\$11,901,589	\$928,071	\$0	\$0	\$12,829,660
Common	\$87,200	\$7,244	\$0	\$94,444	\$87,584	\$6,860	\$0	\$0	\$94,444
<b>Total Gas</b>	<b>\$14,100,580</b>	<b>\$982,759</b>	<b>\$0</b>	<b>\$15,083,339</b>	<b>\$13,987,740</b>	<b>\$1,085,599</b>	<b>\$0</b>	<b>\$0</b>	<b>\$15,083,339</b>
<b>Total Operating</b>	<b>\$123,430,031</b>	<b>\$3,081,627</b>	<b>\$3,421,678</b>	<b>\$129,933,335</b>	<b>\$107,230,131</b>	<b>\$5,994,188</b>	<b>\$4,857,374</b>	<b>\$495,124</b>	<b>\$118,576,817</b>

<sup>1</sup> Net of Interchange Agreement billings to NSPW

Northern States Power Company- Minnesota  
2011 Property Taxes Accrued for 2011

Case No. PU-12-813  
Data Request NDPSC-5-056  
Attachment A - Page 2 of 5

	Property Taxes Paid (by Source State)				Jurisdictional Allocation of Property Tax Expense <sup>1</sup>				
	2011 Minn	2011 No Dak	2011 So Dak	2011 TOTAL	2011 Minn	2011 No Dak	2011 So Dak	2011 Wholesale	2011 TOTAL
<b>Electric</b>									
Production	\$48,630,000	\$0	\$812,000	\$49,442,000	\$36,865,353	\$2,407,567	\$2,311,110	\$49,306	\$41,433,335
Transmission	\$28,453,000	\$359,000	\$873,000	\$27,685,000	\$20,530,729	\$1,348,115	\$1,294,104	\$27,609	\$23,200,556
Distribution	\$45,409,000	\$1,487,000	\$1,415,000	\$48,311,000	\$45,409,000	\$1,487,000	\$1,415,000	\$0	\$48,311,000
Common	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
<b>Total Electric</b>	<b>\$120,492,000</b>	<b>\$1,846,000</b>	<b>\$3,100,000</b>	<b>\$125,438,000</b>	<b>\$102,605,082</b>	<b>\$5,242,682</b>	<b>\$5,020,214</b>	<b>\$76,914</b>	<b>\$112,944,891</b>
<b>Gas</b>									
Production	\$1,305,000	\$13,000	\$0	\$1,318,000	\$1,178,802	\$139,198	\$0	\$0	\$1,318,000
Transmission	\$953,000	\$28,000	\$0	\$981,000	\$953,000	\$28,000	\$0	\$0	\$981,000
Distribution	\$12,850,000	\$813,000	\$0	\$13,463,000	\$12,650,000	\$813,000	\$0	\$0	\$13,463,000
Common	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
<b>Total Gas</b>	<b>\$14,908,000</b>	<b>\$854,000</b>	<b>\$0</b>	<b>\$15,762,000</b>	<b>\$14,781,802</b>	<b>\$980,198</b>	<b>\$0</b>	<b>\$0</b>	<b>\$15,762,000</b>
<b>Total Operating</b>	<b>\$135,400,000</b>	<b>\$2,700,000</b>	<b>\$3,100,000</b>	<b>\$141,200,000</b>	<b>\$117,386,884</b>	<b>\$6,222,879</b>	<b>\$5,020,214</b>	<b>\$76,914</b>	<b>\$128,706,891</b>

<sup>1</sup> Net of Interchange Agreement billings to NSPW

Northern States Power Company- Minnesota  
2012 Property Taxes Accrued for 2012

Case No. PU-12-813  
Data Request NDPSC-5-056  
Attachment A - Page 3 of 5

	Property Taxes Paid (by Source State)				Jurisdictional Allocation of Property Tax Expense <sup>1</sup>				
	2012 Minn	2012 No Dak	2012 So Dak	2012 TOTAL	2012 Minn	2012 No Dak	2012 So Dak	2012 Wholesale	2012 TOTAL
<b>Electric</b>									
Production	\$60,709,000	\$0	\$864,000	\$61,573,000	\$45,948,541	\$3,147,698	\$3,136,723	\$30,940	\$52,263,901
Transmission	\$31,771,000	\$399,000	\$930,000	\$33,100,000	\$24,700,708	\$1,692,118	\$1,686,218	\$16,633	\$28,095,677
Distribution	\$54,497,000	\$1,652,000	\$1,506,000	\$57,655,000	\$54,497,000	\$1,652,000	\$1,506,000	\$0	\$57,655,000
Common	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
<b>Total Electric</b>	<b>\$146,977,000</b>	<b>\$2,051,000</b>	<b>\$3,300,000</b>	<b>\$152,328,000</b>	<b>\$125,146,248</b>	<b>\$6,491,816</b>	<b>\$6,328,941</b>	<b>\$47,573</b>	<b>\$138,014,578</b>
<b>Gas</b>									
Production	\$1,589,000	\$15,000	\$0	\$1,604,000	\$1,433,378	\$170,622	\$0	\$0	\$1,604,000
Transmission	\$1,152,000	\$31,000	\$0	\$1,183,000	\$1,152,000	\$31,000	\$0	\$0	\$1,183,000
Distribution	\$15,282,000	\$903,000	\$0	\$16,185,000	\$15,282,000	\$903,000	\$0	\$0	\$16,185,000
Common	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
<b>Total Gas</b>	<b>\$18,023,000</b>	<b>\$949,000</b>	<b>\$0</b>	<b>\$18,972,000</b>	<b>\$17,667,378</b>	<b>\$1,104,622</b>	<b>\$0</b>	<b>\$0</b>	<b>\$18,972,000</b>
<b>Total Operating</b>	<b>\$165,000,000</b>	<b>\$3,000,000</b>	<b>\$3,300,000</b>	<b>\$171,300,000</b>	<b>\$143,013,626</b>	<b>\$7,596,439</b>	<b>\$6,328,941</b>	<b>\$47,573</b>	<b>\$156,986,578</b>

<sup>1</sup> Net of Interchange Agreement billings to NSPW

Northern States Power Company- Minnesota  
2013 Test Year Property Taxes

Case No. PU-12-813  
Data Request NDPSC-5-086  
Attachment A - Page 4 of 5

	Property Taxes Paid (by Source State)				Jurisdictional Allocation of Property Tax Expense <sup>1</sup>				
	2013 Minn	2013 No Dak	2013 So Dak	2013 TOTAL	2013 Minn	2013 No Dak	2013 So Dak	2013 Wholesale	2013 TOTAL
<b>Electric</b>									
Production	\$66,850,000	\$0	\$812,000	\$67,662,000	\$50,482,428	\$3,458,976	\$3,446,915	\$34,000	\$57,432,318
Transmission	\$35,049,000	\$399,000	\$873,000	\$36,321,000	\$27,104,363	\$1,856,780	\$1,850,308	\$18,251	\$30,829,701
Distribution	\$80,120,000	\$1,652,000	\$1,415,000	\$63,187,000	\$60,120,000	\$1,652,000	\$1,415,000	\$0	\$63,187,000
Common	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
<b>Total Electric</b>	<b>\$162,019,000</b>	<b>\$2,051,000</b>	<b>\$3,100,000</b>	<b>\$167,170,000</b>	<b>\$137,716,789</b>	<b>\$8,967,757</b>	<b>\$6,712,222</b>	<b>\$52,251</b>	<b>\$151,449,018</b>
<b>Gas</b>									
Production	\$1,752,000	\$15,000	\$0	\$1,767,000	\$1,573,377	\$193,623	\$0	\$0	\$1,767,000
Transmission	\$1,271,000	\$31,000	\$0	\$1,302,000	\$1,271,000	\$31,000	\$0	\$0	\$1,302,000
Distribution	\$16,858,000	\$903,000	\$0	\$17,761,000	\$16,858,000	\$903,000	\$0	\$0	\$17,761,000
Common	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
<b>Total Gas</b>	<b>\$19,881,000</b>	<b>\$949,000</b>	<b>\$0</b>	<b>\$20,830,000</b>	<b>\$19,702,377</b>	<b>\$1,127,623</b>	<b>\$0</b>	<b>\$0</b>	<b>\$20,830,000</b>
<b>Total Operating</b>	<b>\$181,900,000</b>	<b>\$3,000,000</b>	<b>\$3,100,000</b>	<b>\$188,000,000</b>	<b>\$157,419,166</b>	<b>\$8,095,379</b>	<b>\$6,712,222</b>	<b>\$52,251</b>	<b>\$172,279,018</b>

<sup>1</sup> Net of Interchange Agreement billings to NSPW

Northern States Power Company- Minnesota  
2013 Test Year Property Taxes - Updated

Case No. PU-12-813  
Data Request NDPSC-5-056  
Attachment A - Page 5 of 5

	Property Taxes Paid (by Source State)				Jurisdictional Allocation of Property Tax Expense <sup>1</sup>				
	2013	2013	2013	2013	2013	2013	2013	2013	2013
	Minn	No Dak	So Dak	TOTAL	Minn	No Dak	So Dak	Wholesale	TOTAL
<b>Electric</b>									
Production	\$69,065,000	\$0	\$812,000	\$69,877,000	\$52,145,359	\$3,572,210	\$3,559,754	\$35,113	\$59,312,436
Transmission	\$36,233,000	\$399,000	\$873,000	\$37,505,000	\$27,987,917	\$1,917,308	\$1,910,623	\$18,846	\$31,834,694
Distribution	\$62,149,000	\$1,652,000	\$1,415,000	\$65,216,000	\$62,149,000	\$1,652,000	\$1,415,000	\$0	\$65,216,000
Common	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
<b>Total Electric</b>	<b>\$167,447,000</b>	<b>\$2,051,000</b>	<b>\$3,100,000</b>	<b>\$172,598,000</b>	<b>\$142,282,276</b>	<b>\$7,141,518</b>	<b>\$6,885,377</b>	<b>\$53,959</b>	<b>\$156,363,130</b>
<b>Gas</b>									
Production	\$1,812,000	\$15,000	\$0	\$1,827,000	\$1,626,803	\$200,197	\$0	\$0	\$1,827,000
Transmission	\$1,314,000	\$31,000	\$0	\$1,345,000	\$1,314,000	\$31,000	\$0	\$0	\$1,345,000
Distribution	\$17,427,000	\$903,000	\$0	\$18,330,000	\$17,427,000	\$903,000	\$0	\$0	\$18,330,000
Common	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
<b>Total Gas</b>	<b>\$20,553,000</b>	<b>\$949,000</b>	<b>\$0</b>	<b>\$21,502,000</b>	<b>\$20,367,803</b>	<b>\$1,134,197</b>	<b>\$0</b>	<b>\$0</b>	<b>\$21,502,000</b>
<b>Total Operating</b>	<b>\$188,000,000</b>	<b>\$3,000,000</b>	<b>\$3,100,000</b>	<b>\$194,100,000</b>	<b>\$162,650,078</b>	<b>\$8,275,715</b>	<b>\$6,885,377</b>	<b>\$53,959</b>	<b>\$177,865,130</b>

<sup>1</sup> Net of Interchange Agreement billings to NSPW

Northern States Power Company  
 Electric Utility - State of North Dakota  
 Property Tax  
 2013 Forecast Update - DOR Actual 2013 Capitalization Rate

2013 Forecast Update Property Taxes

	2013 Property Taxes Total			2013 TOTAL	Jurisdiction Total				2013 TOTAL	ND St * IA Alloc 2013 Total ND St Net of IA
	2013 Total Minn	2013 Total No Dak	2013 Total So Dak		2013 Total Minn	2013 Total No Dak	2013 Total So Dak	2013 Total Wholesale		
<b>Electric</b>										
1 Production	69,065,000	0	812,000	69,877,000	61,433,343	4,208,482	4,193,808	41,367	69,877,000	3,572,210
2 Transmission	36,233,000	399,000	873,000	37,505,000	32,973,046	2,258,814	2,250,938	22,203	37,505,000	1,917,308
3 Distribution	62,149,000	1,652,000	1,415,000	65,216,000	62,149,000	1,652,000	1,415,000	0	65,216,000	1,652,000
4 Common	0	0	0	0	0	0	0	0	0	0
5 Total Electric	167,447,000	2,051,000	3,100,000	172,598,000	156,555,389	8,119,296	7,859,745	63,570	172,598,000	7,141,518
<b>Gas</b>										
6 Production	1,812,000	15,000	0	1,827,000	1,626,803	200,197	0	0	1,827,000	
7 Transmission	1,314,000	31,000	0	1,345,000	1,314,000	31,000	0	0	1,345,000	
8 Distribution	17,427,000	903,000	0	18,330,000	17,427,000	903,000	0	0	18,330,000	
9 Common	0	0	0	0	0	0	0	0	0	
10 Total Gas	20,553,000	949,000	0	21,502,000	20,367,803	1,134,197	0	0	21,502,000	
11 Total Operating	188,000,000	3,000,000	3,100,000	194,100,000	176,923,191	9,253,493	7,859,745	63,570	194,100,000	

to Page 1

Allocators:

			NSPM Jurisdiction Allocators				TOTAL
			Minn	No Dak	So Dak	Wholesale	
<b>NSPM Company Allocators</b>							
Electric	Production	E12CP	87.9164%	6.0227%	6.0017%	0.0592%	100.0000%
	Transmission	E12CPT	87.9164%	6.0227%	6.0017%	0.0592%	100.0000%
<b>Gas</b>							
Production	GDDAY		89.0423%	10.9577%			100.0000%
<b>Interchange Agreement Demand Allocators</b>							
			NSPM CO	NSPW CO	TOTAL		
Electric	Production	36 month CP	84.8812%	15.1188%	100.0000%		
	Transmission	36 month CP	84.8812%	15.1188%	100.0000%		

- Non Public Document – Contains Trade Secret Data  
 Public Document – Trade Secret Data Excised  
 Public Document

Xcel Energy

Case No.: PU-12-813

Response To: North Dakota Public Service Commission      Data Request No.      NDPSC-5-039

Requestor: Snavelly King

Date Received: March 29, 2013

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Question:

Witness: Anne E. Heuer-Revenue Requirement (Exhibit AEH-1)

Please refer to page 27 of the Heuer Testimony, Net Sales and Growth in Margin, in the amount of \$(1.8 million). (Exhibit AEH-1, Schedule 9, page 1 of 2). Please provide a breakdown of the additional customers added to the system, and the corresponding usage associated with each customer. Provide the same information for the years 2011 and 2012.

Response:

Attachment A to this response provides the net change by class in customer counts and weather normalized use per customer for 2010, 2011, 2012, and 2013.

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Preparer: Jannell E. Marks

Title: Director

Department: Load Forecasting and Analysis

Telephone: 303-571-6254

Date: April 29, 2013

Northern States Power Company  
Electric Utility - State of North Dakota

Case No. PU-12-813  
NDPSC Data Request 5-039  
Attachment A - Page 1 of 1

**North Dakota Customer Counts and Use per Customer**

	Year-End Customer Counts				Annual Change		
	<u>2010</u>	<u>2011</u>	<u>2012</u>	<u>2013 TY</u>	<u>2011</u>	<u>2012</u>	<u>2013 TY</u>
Residential without Space Heating	56,472	55,144	56,565	57,638	-1,328	1,421	1,073
Residential with Space Heating	19,847	20,982	20,666	20,409	1,135	-316	-257
Small Commercial & Industrial	12,078	12,033	12,182	12,319	-45	149	137
Large Commercial & Industrial	20	20	21	21	0	1	0
Street Lighting	96	100	127	129	4	27	2
Other	<u>188</u>	<u>180</u>	<u>186</u>	<u>187</u>	<u>-8</u>	<u>6</u>	<u>1</u>
Total Retail	88,701	88,459	89,747	90,703	-242	1,288	956

	Use per Customer (kWh) (Weather Normalized)				Annual Change		
	<u>2010</u>	<u>2011</u>	<u>2012</u>	<u>2013 TY</u>	<u>2011</u>	<u>2012</u>	<u>2013 TY</u>
Residential without Space Heating	9,194	9,279	9,202	9,340	85	-77	138
Residential with Space Heating	12,774	12,696	12,546	12,377	-78	-150	-169
Small Commercial & Industrial	88,098	90,227	89,133	88,910	2,129	-1,093	-224
Large Commercial & Industrial	17,705,231	17,538,213	16,958,562	17,481,288	-167,018	-579,651	522,726
Street Lighting	171,560	162,366	135,965	127,083	-9,194	-26,401	-8,882
Other	70,459	75,470	72,575	69,123	5,010	-2,895	-3,452

Pages 200 through 205 were duplicates of pages 100 through 105 and do not therefore need to be replaced.

Northern States Power Company  
Electric Utility - State of North Dakota  
SUMMARY OF REVENUE REQUIREMENTS  
Test Year Ending December 31, 2013  
(\$000's)

Case No. PU-12-\_\_\_\_  
Exhibit\_\_\_\_(Notice)  
Schedule 1  
Page 1 of 1

<u>Line</u>	<u>Description</u>	Adjusted Proposed Test Year <u>2013</u>
1	Average Rate Base	\$377,648
2	Operating Income (Before AFUDC)	\$19,415
3	Allowance for Funds Used During Construction	\$0
4	Total Available for Return (Line 2 + Line 3 + Rounding)	\$19,415
5	Overall Rate of Return (Line 4 / Line 1)	5.14%
6	Required Rate of Return	7.90%
7	Operating Income Requirement (Line 1 x Line 6)	\$29,834
8	Income Deficiency (Line 7 - Line 4)	\$10,419
9	Gross Revenue Conversion Factor	1.62201
10	Revenue Deficiency (Line 8 x Line 9)	\$16,900
11	Retail Related Revenue Under Present Rates	\$182,724
13	Percentage Increase Needed in Overall Revenue (Line 10 / Line 11)	9.25%

Northern States Power Company  
Electric Utility - North Dakota Retail Jurisdiction  
Test Year Ending December 31, 2013  
**SALES AND REVENUE BY RATE SCHEDULE**

Case No. PU-12-\_\_\_\_\_  
Exhibit No. \_\_\_\_\_(Notice)  
Schedule 2  
Page 1 of 1

Service Schedule	Test Year 2013 Revenues (\$1,000's)											
	Average Customers	MWH Sales			Summer		Winter		Annual		Increase	
		Summer	Winter	Annual	Present	Proposed	Present	Proposed	Present	Proposed	Amount	Percent
<b>Residential</b>												
Residential	77,036	225,451	553,204	778,654	23,161	25,117	46,928	51,241	70,089	76,358	6,270	8.95%
Residential TOD	27	173	570	743	17	18	41	44	58	62	5	8.30%
Load Management	387	404	4,949	5,353	31	35	287	322	319	356	37	11.76%
<b>Res Total</b>	<b>77,450</b>	<b>226,027</b>	<b>558,723</b>	<b>784,751</b>	<b>23,209</b>	<b>25,170</b>	<b>47,256</b>	<b>51,607</b>	<b>70,465</b>	<b>76,777</b>	<b>6,312</b>	<b>8.96%</b>
<b>C&amp;I - Non-Demand</b>												
Small General	8,162	35,456	83,447	118,902	3,654	3,937	7,295	7,923	10,949	11,859	910	8.31%
Small General TOD	473	1,180	2,597	3,777	145	155	261	282	406	436	31	7.57%
Load Management	86	197	2,050	2,247	16	17	119	133	135	150	15	11.17%
<b>C&amp;I N-D Total</b>	<b>8,721</b>	<b>36,832</b>	<b>88,094</b>	<b>124,926</b>	<b>3,814</b>	<b>4,108</b>	<b>7,675</b>	<b>8,337</b>	<b>11,490</b>	<b>12,445</b>	<b>955</b>	<b>8.32%</b>
<b>C&amp;I - Demand</b>												
General	3,202	231,445	448,673	680,119	21,041	23,047	34,879	38,370	55,921	61,417	5,496	9.83%
General TOD	170	72,232	135,955	208,187	5,398	5,854	9,010	9,798	14,408	15,652	1,244	8.63%
Peak-Controlled	74	13,979	35,923	49,902	1,146	1,274	2,736	3,035	3,882	4,309	427	10.99%
Peak-Controlled TOD	15	38,208	83,336	121,544	2,568	2,791	5,126	5,564	7,694	8,355	661	8.59%
Energy-Controlled	89	94,689	174,331	269,019	5,659	6,233	10,232	11,255	15,891	17,488	1,597	10.05%
Real Time Pricing	0	0	0	0	0	0	0	0	0	0	0	
<b>C&amp;I Dmd Total</b>	<b>3,551</b>	<b>450,553</b>	<b>878,217</b>	<b>1,328,771</b>	<b>35,812</b>	<b>39,198</b>	<b>61,984</b>	<b>68,022</b>	<b>97,796</b>	<b>107,220</b>	<b>9,424</b>	<b>9.64%</b>
<b>C&amp;I Total</b>	<b>12,272</b>	<b>487,386</b>	<b>966,311</b>	<b>1,453,697</b>	<b>39,626</b>	<b>43,307</b>	<b>69,659</b>	<b>76,359</b>	<b>109,286</b>	<b>119,665</b>	<b>10,380</b>	<b>9.50%</b>
<b>Public Authorities</b>												
Small Mun Pumping	91	254	608	862	28	30	56	61	84	91	7	8.30%
Municipal Pumping	97	4,072	8,004	12,076	391	423	638	691	1,029	1,114	85	8.28%
Siren Service	0	0	0	0	0	0	1	1	1	1	0	9.62%
<b>PA Total</b>	<b>187</b>	<b>4,326</b>	<b>8,612</b>	<b>12,938</b>	<b>419</b>	<b>454</b>	<b>695</b>	<b>753</b>	<b>1,114</b>	<b>1,206</b>	<b>92</b>	<b>8.29%</b>
<b>Lighting</b>												
System Service	0	638	1,728	2,366	166	189	341	388	507	577	70	13.88%
Energy	0	3,322	8,995	12,317	289	295	625	637	914	932	18	1.98%
Metered Energy	76	430	1,165	1,596	26	26	68	68	94	94	0	0.01%
Protective Lighting	0	781	2,275	3,057	110	110	235	235	345	345	0	0.03%
<b>Lighting Total</b>	<b>76</b>	<b>5,172</b>	<b>14,163</b>	<b>19,336</b>	<b>590</b>	<b>620</b>	<b>1,269</b>	<b>1,328</b>	<b>1,860</b>	<b>1,948</b>	<b>89</b>	<b>4.77%</b>
<b>Total Retail</b>	<b>89,985</b>	<b>722,911</b>	<b>1,547,810</b>	<b>2,270,721</b>	<b>63,845</b>	<b>69,551</b>	<b>118,879</b>	<b>130,046</b>	<b>182,724</b>	<b>199,597</b>	<b>16,873</b>	<b>9.23%</b>
Other Rev Increase					0	9	0	18	0	27	27	
<b>Total Revenue</b>	<b>89,985</b>	<b>722,911</b>	<b>1,547,810</b>	<b>2,270,721</b>	<b>63,845</b>	<b>69,559</b>	<b>118,879</b>	<b>130,064</b>	<b>182,724</b>	<b>199,624</b>	<b>16,900</b>	<b>9.25%</b>

Northern States Power Company  
Electric Utility - North Dakota Retail Jurisdiction  
Test Year Ending December 31, 2013  
**Comparison Of Present & Proposed Rates**

Case No. PU-12-\_\_\_\_\_  
Exhibit No. \_\_\_\_\_(Notice)  
Schedule 3  
Page 1 of 6

Fuel Cost - Retail	Present			Proposed		
	Summer	Winter	Annual	Summer	Winter	Annual
<b>Retail</b>	2.716 ¢	2.732 ¢	2.727 ¢	2.716 ¢	2.732 ¢	2.727 ¢
<b>Residential</b>	2.723 ¢	2.739 ¢	2.734 ¢	2.708 ¢	2.724 ¢	2.719 ¢
<b>C&amp;I - Non-Demand</b>	2.792 ¢	2.809 ¢	2.804 ¢	2.802 ¢	2.819 ¢	2.814 ¢
<b>C&amp;I-Dmd - Non-TOD</b>			2.773 ¢			2.777 ¢
<b>C&amp;I-Dmd -TOD On-Peak</b>			3.513 ¢			3.490 ¢
<b>C&amp;I-Dmd -TOD Off-Peak</b>			2.151 ¢			2.169 ¢
<b>Lighting</b>			2.029 ¢			2.002 ¢

		Present	Proposed	Present	Proposed
<b>Residential (D01, D03)</b>		Base Rates		Rates + Fuel	
<b>Customer / Mo.</b>	<b>Overhead</b>	\$9.00	\$10.00	\$9.00	\$10.00
	Overhead - Electric Sp Ht	\$12.00	\$13.00	\$12.00	\$13.00
	Underground	\$11.00	\$12.00	\$11.00	\$12.00
	Underground - Electric Sp Ht	\$14.00	\$15.00	\$14.00	\$15.00
<b>Energy / kWh</b>	Summer	6.466 ¢	7.233 ¢	9.189 ¢	9.941 ¢
	<b>Winter</b>	4.997 ¢	5.733 ¢	7.736 ¢	8.457 ¢
	Winter - Electric Space Heat	3.997 ¢	4.583 ¢	6.736 ¢	7.307 ¢

		Present	Proposed	Present	Proposed
<b>Residential Time of Day (D02, D04)</b>		Base Rates		Rates + Fuel	
<b>Customer / Mo.</b>	Overhead	\$11.00	\$12.00	\$11.00	\$12.00
	Overhead - Electric Sp Ht	\$14.00	\$15.00	\$14.00	\$15.00
	Underground	\$13.00	\$14.00	\$13.00	\$14.00
	Underground - Electric Sp Ht	\$16.00	\$17.00	\$16.00	\$17.00
<b>Energy / kWh</b>	On-Peak Summer	13.634 ¢	14.988 ¢	16.357 ¢	17.696 ¢
	On-Peak Winter	9.685 ¢	10.977 ¢	12.424 ¢	13.701 ¢
	On-Peak Winter -Elec. Sp Ht	7.212 ¢	8.170 ¢	9.951 ¢	10.894 ¢
	Off-Peak Summer	2.220 ¢	2.600 ¢	4.943 ¢	5.308 ¢
	Off-Peak Winter	2.220 ¢	2.600 ¢	4.959 ¢	5.324 ¢

		Present	Proposed	Present	Proposed
<b>Energy-Controlled Non-Demand (D05)</b>		Base Rates		Rates + Fuel	
<b>Customer / Mo.</b>		\$4.20	\$4.60	\$4.20	\$4.60
<b>Energy / kWh</b>	Standard Resid.	2.9340 ¢	3.6630 ¢	5.668 ¢	6.382 ¢
	Standard Comm.	2.9340 ¢	3.6630 ¢	5.738 ¢	6.477 ¢
	Optional Resid. - Summer	6.466 ¢	7.233 ¢	9.189 ¢	9.941 ¢
	Optional Comm.- Summer	6.468 ¢	7.159 ¢	9.260 ¢	9.961 ¢

Northern States Power Company  
Electric Utility - North Dakota Retail Jurisdiction  
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			Present	Proposed	Present	Proposed
<b>Limited Off-Peak (D10)</b>			<b>Base Rates</b>		<b>Rates + Fuel</b>	
<b>Customer / Mo.</b>	Residential		\$4.20	\$4.60	\$4.20	\$4.60
	Commercial	Sec. 1 Phase	\$4.20	\$4.60	\$4.20	\$4.60
	Commercial	Sec. 3 Phase	\$6.00	\$6.50	\$6.00	\$6.50
	Commercial	Primary	\$30.00	\$30.00	\$30.00	\$30.00
<b>Energy / kWh</b>	Residential	On-Peak	24.000 ¢	26.000 ¢	26.734 ¢	28.719 ¢
	Commercial	On-Peak	24.000 ¢	26.000 ¢	26.804 ¢	28.814 ¢
	Residential	Secondary	1.920 ¢	2.300 ¢	4.654 ¢	5.019 ¢
	Commercial	Secondary	1.920 ¢	2.300 ¢	4.724 ¢	5.114 ¢
	Commercial	Primary	1.825 ¢	2.199 ¢	4.629 ¢	5.013 ¢

			Present	Proposed	Present	Proposed
<b>Small General (D12, D15)</b>			<b>Base Rates</b>		<b>Rates + Fuel</b>	
<b>Customer / Mo.</b>	Metered (D12)		\$12.00	\$13.00	\$12.00	\$13.00
<b>Demand / kW</b>	Direct Current (D15)		\$1.48	Cancel	\$1.48	Cancel
<b>Energy / kWh</b>	Summer		6.468 ¢	7.159 ¢	9.260 ¢	9.961 ¢
	Winter		4.999 ¢	5.659 ¢	7.808 ¢	8.478 ¢

			Present	Proposed	Present	Proposed
<b>Small Municipal Pumping (D40)</b>			<b>Base Rates</b>		<b>Rates + Fuel</b>	
<b>Customer / Mo.</b>	Overhead		\$12.00	\$13.00	\$12.00	\$13.00
<b>Energy / kWh</b>	Summer		6.468 ¢	7.159 ¢	9.260 ¢	9.961 ¢
	Winter		4.999 ¢	5.659 ¢	7.808 ¢	8.478 ¢

			Present	Proposed	Present	Proposed
<b>Small General TOD (D14, D18, D19, D34)</b>			<b>Base Rates</b>		<b>Rates + Fuel</b>	
<b>Customer / Mo.</b>	TOD Metered (D14)		\$14.00	\$15.00	\$14.00	\$15.00
	KWH Metered (D19)		\$12.00	\$13.00	\$12.00	\$13.00
	Unmetered (D18)		\$9.00	\$10.00	\$9.00	\$10.00
	Low Wattage <100W (D34)		\$0.27	\$0.30	\$0.27	\$0.30
	Low Wattage <400W (D34)		\$1.12	\$1.24	\$1.12	\$1.24
<b>Energy / kWh</b>	On-Peak Summer		11.455 ¢	12.352 ¢	14.247 ¢	15.154 ¢
	On-Peak Winter		8.261 ¢	9.143 ¢	11.070 ¢	11.962 ¢
	Off-Peak Summer		2.220 ¢	2.600 ¢	5.012 ¢	5.402 ¢
	Off-Peak Winter		2.220 ¢	2.600 ¢	5.029 ¢	5.419 ¢
	Constant Use - Summer		5.452 ¢	6.013 ¢	8.244 ¢	8.815 ¢
	Constant Use - Winter		4.334 ¢	4.890 ¢	7.143 ¢	7.709 ¢

Northern States Power Company  
Electric Utility - North Dakota Retail Jurisdiction  
Test Year Ending December 31, 2013  
**Comparison Of Present & Proposed Rates**

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		Present	Proposed	Present	Proposed
<b>Demand-Metered Voltage Discounts</b>		Base Rates		Rates + Fuel	
<b>Voltage Discount / kWh</b>	Primary	0.095 ¢	0.101 ¢	0.095 ¢	0.101 ¢
	Transmission Transformed	0.200 ¢	0.210 ¢	0.200 ¢	0.210 ¢
	Transmission	0.220 ¢	0.240 ¢	0.220 ¢	0.240 ¢
<b>Voltage Discount / kW</b>	Primary	\$0.62	\$0.60	\$0.62	\$0.60
	Transmission Transformed	\$1.10	\$1.10	\$1.10	\$1.10
	Transmission	\$1.40	\$1.50	\$1.40	\$1.50
<b>General (D16)</b>		Base Rates		Rates + Fuel	
<b>Customer / Mo.</b>		\$22.00	\$24.35	\$22.00	\$24.35
<b>Demand / kW</b>	Summer	\$11.70	\$13.40	\$11.70	\$13.40
	Winter	\$7.90	\$9.40	\$7.90	\$9.40
<b>Energy / kWh</b>		2.546 ¢	2.854 ¢	5.319 ¢	5.631 ¢
<b>Energy Credit / kWh</b>		-0.900 ¢	-1.000 ¢	-0.900 ¢	-1.000 ¢
<b>Municipal Pumping (D41)</b>		Base Rates		Rates + Fuel	
<b>Customer / Mo.</b>		\$22.00	\$24.35	\$22.00	\$24.35
<b>Demand / kW</b>	Summer	\$11.70	\$13.40	\$11.70	\$13.40
	Winter	\$7.90	\$9.40	\$7.90	\$9.40
<b>Energy / kWh</b>		2.546 ¢	2.854 ¢	5.319 ¢	5.631 ¢
<b>Energy Credit / kWh</b>		-0.900 ¢	-1.000 ¢	-0.900 ¢	-1.000 ¢
<b>General Time of Day (D17)</b>		Base Rates		Rates + Fuel	
<b>Customer / Mo.</b>		\$25.00	\$27.35	\$25.00	\$27.35
<b>On-Peak Demand / kW</b>	Summer	\$11.70	\$13.40	\$11.70	\$13.40
	Winter	\$7.90	\$9.40	\$7.90	\$9.40
<b>Off-Peak Demand / kW</b>		\$1.40	\$1.50	\$1.40	\$1.50
<b>Energy / kWh</b>	On-Peak	3.334 ¢	3.846 ¢	6.847 ¢	7.336 ¢
	Off-Peak	1.973 ¢	2.113 ¢	4.124 ¢	4.282 ¢
<b>Energy Credit / kWh</b>		-0.900 ¢	-1.000 ¢	-0.900 ¢	-1.000 ¢
<b>Peak-Controlled (D20)</b>		Base Rates		Rates + Fuel	
<b>Customer / Mo.</b>		\$50.00	\$54.00	\$50.00	\$54.00
<b>Firm Demand / kW</b>	Summer	\$11.70	\$13.40	\$11.70	\$13.40
	Winter	\$7.90	\$9.40	\$7.90	\$9.40
<b>Control Demand / kW</b>	Tier 2 - Level A	\$6.28	\$7.78	\$6.28	\$7.78
	Tier 2 - Level B	\$5.80	\$7.14	\$5.80	\$7.14
	Tier 2 - Level C	\$5.40	\$6.70	\$5.40	\$6.70
	Tier 1 - Level A	\$5.65	\$7.22	\$5.65	\$7.22
	Tier 1 - Level B	\$5.20	\$6.50	\$5.20	\$6.50
	Tier 1 - Level C	\$4.70	\$5.97	\$4.70	\$5.97
<b>Energy / kWh</b>		2.546 ¢	2.854 ¢	5.319 ¢	5.631 ¢
<b>Energy Credit / kWh</b>		-0.900 ¢	-1.000 ¢	-0.900 ¢	-1.000 ¢

Northern States Power Company  
Electric Utility - North Dakota Retail Jurisdiction  
Test Year Ending December 31, 2013  
**Comparison Of Present & Proposed Rates**

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		Present	Proposed	Present	Proposed
<b>Peak-Controlled TOD (D21)</b>		<b>Base Rates</b>		<b>Rates + Fuel</b>	
<b>Customer / Mo.</b>		\$50.00	\$54.00	\$50.00	\$54.00
<b>On-Peak Demand / kW</b>	Summer	\$11.70	\$13.40	\$11.70	\$13.40
	Winter	\$7.90	\$9.40	\$7.90	\$9.40
<b>Control Demand / kW</b>	Tier 2 - Level A	\$6.28	\$7.78	\$6.28	\$7.78
	Tier 2 - Level B	\$5.80	\$7.14	\$5.80	\$7.14
	Tier 2 - Level C	\$5.40	\$6.70	\$5.40	\$6.70
	Tier 1 - Level A	\$5.65	\$7.22	\$5.65	\$7.22
	Tier 1 - Level B	\$5.20	\$6.50	\$5.20	\$6.50
	Tier 1 - Level C	\$4.70	\$5.97	\$4.70	\$5.97
<b>Off-Peak Demand / kW</b>		\$1.40	\$1.50	\$1.40	\$1.50
<b>Energy / kWh</b>	On-Peak	3.334 ¢	3.846 ¢	6.847 ¢	7.336 ¢
	Off-Peak	1.973 ¢	2.113 ¢	4.124 ¢	4.282 ¢
<b>Energy Credit / kWh</b>		-0.9000 ¢	-1.0000 ¢	-0.9000 ¢	-1.0000 ¢

		Present	Proposed	Present	Proposed
<b>Tier 1 Energy-Controlled Rider (D22)</b>		<b>Base Rates</b>		<b>Rates + Fuel</b>	
<b>Customer / Mo.</b>		\$50.00	\$54.00	\$50.00	\$54.00
<b>On-Peak Demand / kW</b>	Summer	\$11.70	\$13.40	\$11.70	\$13.40
	Winter	\$7.90	\$9.40	\$7.90	\$9.40
<b>Control Demand / kW</b>	Tier 1 - Level A	\$5.65	\$7.22	\$5.65	\$7.22
	Tier 1 - Level B	\$5.20	\$6.50	\$5.20	\$6.50
	Tier 1 - Level C	\$4.70	\$5.97	\$4.70	\$5.97
<b>Off-Peak Demand / kW</b>		\$1.40	\$1.50	\$1.40	\$1.50
<b>Energy / kWh</b>	Firm On-Peak	3.334 ¢	3.846 ¢	6.847 ¢	7.336 ¢
	Firm Off-Peak	1.973 ¢	2.113 ¢	4.124 ¢	4.282 ¢
	Controllable On-Peak	3.083 ¢	3.626 ¢	6.596 ¢	7.116 ¢
	Controllable Off-Peak	1.837 ¢	2.013 ¢	3.988 ¢	4.182 ¢
	Control Period Energy	10.000 ¢	10.000 ¢	13.513 ¢	13.490 ¢
<b>Energy Credit / kWh</b>		-0.900 ¢	-1.000 ¢	-0.900 ¢	-1.000 ¢

		Present	Proposed	Present	Proposed
<b>Real-Time Pricing (D62,D63)</b>		<b>Base Rates</b>		<b>Rates + Fuel</b>	
<b>Customer /Month</b>		\$300.00	\$330.00	\$300.00	\$330.00
<b>Contract Demand /kW</b>		\$7.81	\$9.30	\$7.81	\$9.30
<b>Distribution Demand /kW</b>	Secondary	\$1.21	\$1.30	\$1.21	\$1.30
	Primary	\$0.64	\$0.64	\$0.64	\$0.64
	Transmission Transformed	\$0.26	\$0.25	\$0.26	\$0.25
<b>Limited Energy Surcharge /kWh</b>		15.000 ¢	17.900 ¢	15.000 ¢	17.900 ¢
<b>Energy Credit /kWh</b>		-0.770 ¢	-0.860 ¢	-0.770 ¢	-0.860 ¢

		Present	Proposed	Present	Proposed
<b>Fire &amp; Civil Defense Siren (D42)</b>		<b>Base Rates</b>		<b>Rates + Fuel</b>	
<b>HP Capacity / Mo.</b>		\$0.52	\$0.57	\$0.52	\$0.57
<b>Min Charge / Mo.</b>		\$2.48	\$2.58	\$2.48	\$2.58

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		Present	Proposed	Present	Proposed
<b>Automatic Protective Lighting (D11)</b>		Base Rates		Rates + Fuel	
<b>Area</b>	100 W HPSodium	\$6.01	\$6.16	\$6.83	\$6.97
	175 W Mercury	\$6.01	\$6.16	\$7.44	\$8.13
	250 W HPSodium	\$10.66	\$10.66	\$12.82	\$12.79
	400 W Mercury	\$10.66	\$10.66	\$13.89	\$13.98
<b>Directional</b>	250 W HPSodium	\$12.10	\$11.84	\$14.26	\$13.97
	400 W HPSodium	\$14.52	\$14.47	\$17.91	\$17.81
	400 W Mercury	\$12.74	\$13.54	\$15.97	\$16.73

		Present	Proposed	Present	Proposed
<b>Street Lighting System (D30)</b>		Base Rates		Rates + Fuel	
<b>Overhead</b>	100 W HPSodium	\$8.59	\$9.94	\$9.41	\$10.75
	150 W HPSodium	\$9.55	\$10.92	\$10.75	\$12.11
	250 W HPSodium	\$12.06	\$13.74	\$14.22	\$15.87
	400 W HPSodium	\$14.40	\$16.41	\$17.79	\$19.75
<b>Underground</b>	100 W HPSodium	\$16.32	\$19.23	\$17.14	\$20.04
	150 W HPSodium	\$17.35	\$20.25	\$18.55	\$21.44
<b>Decorative UG</b>	100 W HPSodium	\$26.24	\$30.81	\$27.06	\$31.62
	150 W HPSodium	\$27.13	\$31.75	\$28.33	\$32.94
	250 W HPSodium	\$29.26	\$34.04	\$31.42	\$36.17

		Present	Proposed	Present	Proposed
<b>Street Lighting Purchased (D31)</b>		Base Rates		Rates + Fuel	
Group 1	175 W Mercury	\$2.93	\$4.23	\$4.36	\$5.64
	250 W Mercury	\$3.95	\$5.26	\$5.95	\$7.24
	400 W Mercury	\$6.12	\$7.45	\$9.35	\$10.64
	70 W HPSodium	\$2.67	\$2.72	\$3.24	\$3.28
	100 W HPSodium	\$3.12	\$3.17	\$3.94	\$3.98
	150 W HPSodium	\$3.79	\$3.83	\$4.99	\$5.02
	200 W HPSodium	\$4.60	\$4.67	\$6.26	\$6.31
	250 W HPSodium	\$5.47	\$5.54	\$7.63	\$7.67
	310 W HPSodium	\$6.59	\$6.66	\$9.38	\$9.42
	400 W HPSodium	\$7.64	\$7.72	\$11.03	\$11.06
	1000 W HPSodium	\$15.67	\$15.81	\$23.61	\$23.65
Group 4 (Closed)	70 W HPSodium	\$1.42	\$1.47	\$1.99	\$2.03
	100 W HPSodium	\$6.39	\$7.44	\$9.78	\$10.78

<b>Street Lighting Energy - Metered (D33)</b>		Present	Proposed	Present	Proposed
<b>Customer / Mo.</b>		\$5.00	\$5.00	\$5.00	\$5.00
<b>Energy Charge per kWh</b>		3.575 ¢	3.600 ¢	5.604 ¢	5.602 ¢

<b>Street Lighting Purchased (Closed) (D32)</b>		Present	Proposed	Present	Proposed
	1000 L Incandescent	\$2.58	\$2.58	\$3.23	\$3.22
	4000 L Incandescent	\$4.78	\$4.78	\$6.85	\$6.83

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			Present	Proposed
<b>Standby Service Rider</b>				
<b>Customer / Mo.</b>			\$25.00	\$27.35
<b>Demand / Contract kW</b>	Unscheduled Maintenance	Secondary	\$2.33	\$2.61
		Primary	\$1.71	\$2.01
		Tran Transformed	\$1.23	\$1.51
		Transmission	\$0.93	\$1.11
	Scheduled Maintenance	Secondary	\$2.33	\$2.51
		Primary	\$1.61	\$1.91
		Tran Transformed	\$1.13	\$1.41
		Transmission	\$0.83	\$1.01
	Non-Firm	Secondary	\$1.40	\$1.50
		Primary	\$0.78	\$0.90
		Tran Transformed	\$0.30	\$0.40
		Transmission	\$0.00	\$0.00

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**RESIDENTIAL SERVICE (Overhead) - D01**

	Energy in kWh	Monthly Bill		Increase	
		Present	Proposed	Amount	Percent
	250	\$28.34	\$31.14	\$2.80	9.88%
	300	\$32.21	\$35.37	\$3.16	9.82%
	400	\$39.94	\$43.83	\$3.88	9.72%
	500	\$47.68	\$52.28	\$4.60	9.65%
	600	\$55.42	\$60.74	\$5.32	9.60%
WINTER	750	\$67.02	\$73.42	\$6.40	9.55%
	850	\$74.76	\$81.88	\$7.12	9.53%
	1000	\$86.36	\$94.57	\$8.20	9.50%
	1500	\$125.04	\$136.85	\$11.81	9.44%
	2000	\$163.72	\$179.13	\$15.41	9.41%
	3000	\$241.08	\$263.70	\$22.61	9.38%
	4000	\$318.44	\$348.26	\$29.82	9.36%
	5000	\$395.81	\$432.83	\$37.02	9.35%
	250	\$31.97	\$34.85	\$2.88	9.00%
	300	\$36.57	\$39.82	\$3.25	8.90%
	400	\$45.76	\$49.76	\$4.01	8.76%
	500	\$54.95	\$59.70	\$4.76	8.66%
	600	\$64.13	\$69.64	\$5.51	8.59%
SUMMER	750	\$77.92	\$84.55	\$6.64	8.52%
	850	\$87.11	\$94.49	\$7.39	8.48%
	1000	\$100.89	\$109.41	\$8.52	8.44%
	1500	\$146.84	\$159.11	\$12.27	8.36%
	2000	\$192.78	\$208.81	\$16.03	8.32%
	3000	\$284.67	\$308.22	\$23.55	8.27%
	4000	\$376.56	\$407.62	\$31.06	8.25%
	5000	\$468.45	\$507.03	\$38.58	8.23%
	250	\$29.55	\$32.38	\$2.83	9.57%
	300	\$33.66	\$36.85	\$3.19	9.48%
	400	\$41.88	\$45.80	\$3.92	9.37%
	500	\$50.10	\$54.76	\$4.65	9.29%
	600	\$58.32	\$63.71	\$5.38	9.23%
AVERAGE	750	\$70.65	\$77.13	\$6.48	9.17%
MONTHLY	850	\$78.87	\$86.09	\$7.21	9.14%
	1000	\$91.20	\$99.51	\$8.31	9.11%
	1500	\$132.31	\$144.27	\$11.96	9.04%
	2000	\$173.41	\$189.02	\$15.62	9.01%
	3000	\$255.61	\$278.54	\$22.92	8.97%
	4000	\$337.82	\$368.05	\$30.23	8.95%
	5000	\$420.02	\$457.56	\$37.54	8.94%

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**RESIDENTIAL SERVICE - SPACE HEATING (Overhead) - D01**

Energy in kWh	Monthly Bill		Increase		
	Present	Proposed	Amount	Percent	
WINTER	250	\$28.84	\$31.27	\$2.43	8.41%
	300	\$32.21	\$34.92	\$2.71	8.42%
	400	\$38.94	\$42.23	\$3.28	8.43%
	500	\$45.68	\$49.53	\$3.85	8.43%
	600	\$52.42	\$56.84	\$4.42	8.44%
	750	\$62.52	\$67.80	\$5.28	8.44%
	850	\$69.26	\$75.11	\$5.85	8.44%
	1000	\$79.36	\$86.07	\$6.70	8.45%
	1500	\$113.04	\$122.60	\$9.56	8.45%
	2000	\$146.72	\$159.13	\$12.41	8.46%
	3000	\$214.08	\$232.20	\$18.11	8.46%
	4000	\$281.44	\$305.26	\$23.82	8.46%
	5000	\$348.81	\$378.33	\$29.52	8.46%
SUMMER	250	\$34.97	\$37.85	\$2.88	8.23%
	300	\$39.57	\$42.82	\$3.25	8.23%
	400	\$48.76	\$52.76	\$4.01	8.22%
	500	\$57.95	\$62.70	\$4.76	8.21%
	600	\$67.13	\$72.64	\$5.51	8.21%
	750	\$80.92	\$87.55	\$6.64	8.20%
	850	\$90.11	\$97.49	\$7.39	8.20%
	1000	\$103.89	\$112.41	\$8.52	8.20%
	1500	\$149.84	\$162.11	\$12.27	8.19%
	2000	\$195.78	\$211.81	\$16.03	8.19%
	3000	\$287.67	\$311.22	\$23.55	8.18%
	4000	\$379.56	\$410.62	\$31.06	8.18%
	5000	\$471.45	\$510.03	\$38.58	8.18%
AVERAGE MONTHLY	250	\$30.88	\$33.46	\$2.58	8.34%
	300	\$34.66	\$37.55	\$2.89	8.34%
	400	\$42.22	\$45.74	\$3.52	8.35%
	500	\$49.77	\$53.92	\$4.15	8.35%
	600	\$57.32	\$62.11	\$4.78	8.35%
	750	\$68.65	\$74.38	\$5.73	8.35%
	850	\$76.21	\$82.57	\$6.36	8.35%
	1000	\$87.54	\$94.85	\$7.31	8.35%
	1500	\$125.31	\$135.77	\$10.46	8.35%
	2000	\$163.08	\$176.69	\$13.62	8.35%
	3000	\$238.61	\$258.54	\$19.92	8.35%
	4000	\$314.15	\$340.38	\$26.23	8.35%
	5000	\$389.69	\$422.23	\$32.54	8.35%

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**RESIDENTIAL SERVICE (Underground) - D03**

	Energy in kWh	Monthly Bill		Increase	
		Present	Proposed	Amount	Percent
WINTER	250	\$30.34	\$33.14	\$2.80	9.23%
	300	\$34.21	\$37.37	\$3.16	9.24%
	400	\$41.94	\$45.83	\$3.88	9.25%
	500	\$49.68	\$54.28	\$4.60	9.26%
	600	\$57.42	\$62.74	\$5.32	9.27%
	750	\$69.02	\$75.42	\$6.40	9.28%
	850	\$76.76	\$83.88	\$7.12	9.28%
	1000	\$88.36	\$96.57	\$8.20	9.28%
	1500	\$127.04	\$138.85	\$11.81	9.29%
	2000	\$165.72	\$181.13	\$15.41	9.30%
	3000	\$243.08	\$265.70	\$22.61	9.30%
	4000	\$320.44	\$350.26	\$29.82	9.30%
	5000	\$397.81	\$434.83	\$37.02	9.31%
SUMMER	250	\$33.97	\$36.85	\$2.88	8.47%
	300	\$38.57	\$41.82	\$3.25	8.44%
	400	\$47.76	\$51.76	\$4.01	8.39%
	500	\$56.95	\$61.70	\$4.76	8.35%
	600	\$66.13	\$71.64	\$5.51	8.33%
	750	\$79.92	\$86.55	\$6.64	8.30%
	850	\$89.11	\$96.49	\$7.39	8.29%
	1000	\$102.89	\$111.41	\$8.52	8.28%
	1500	\$148.84	\$161.11	\$12.27	8.25%
	2000	\$194.78	\$210.81	\$16.03	8.23%
	3000	\$286.67	\$310.22	\$23.55	8.21%
	4000	\$378.56	\$409.62	\$31.06	8.20%
	5000	\$470.45	\$509.03	\$38.58	8.20%
AVERAGE MONTHLY	250	\$31.55	\$34.38	\$2.83	8.96%
	300	\$35.66	\$38.85	\$3.19	8.95%
	400	\$43.88	\$47.80	\$3.92	8.94%
	500	\$52.10	\$56.76	\$4.65	8.93%
	600	\$60.32	\$65.71	\$5.38	8.93%
	750	\$72.65	\$79.13	\$6.48	8.92%
	850	\$80.87	\$88.09	\$7.21	8.92%
	1000	\$93.20	\$101.51	\$8.31	8.91%
	1500	\$134.31	\$146.27	\$11.96	8.91%
	2000	\$175.41	\$191.02	\$15.62	8.90%
	3000	\$257.61	\$280.54	\$22.92	8.90%
	4000	\$339.82	\$370.05	\$30.23	8.90%
	5000	\$422.02	\$459.56	\$37.54	8.90%

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**RESIDENTIAL SERVICE - SPACE HEATING (Underground) - D03**

	Energy in kWh	Monthly Bill		Increase	
		Present	Proposed	Amount	Percent
WINTER	250	\$30.84	\$33.27	\$2.43	7.87%
	300	\$34.21	\$36.92	\$2.71	7.93%
	400	\$40.94	\$44.23	\$3.28	8.02%
	500	\$47.68	\$51.53	\$3.85	8.08%
	600	\$54.42	\$58.84	\$4.42	8.13%
	750	\$64.52	\$69.80	\$5.28	8.18%
	850	\$71.26	\$77.11	\$5.85	8.21%
	1000	\$81.36	\$88.07	\$6.70	8.24%
	1500	\$115.04	\$124.60	\$9.56	8.31%
	2000	\$148.72	\$161.13	\$12.41	8.34%
	3000	\$216.08	\$234.20	\$18.11	8.38%
	4000	\$283.44	\$307.26	\$23.82	8.40%
	5000	\$350.81	\$380.33	\$29.52	8.42%
SUMMER	250	\$36.97	\$39.85	\$2.88	7.79%
	300	\$41.57	\$44.82	\$3.25	7.83%
	400	\$50.76	\$54.76	\$4.01	7.89%
	500	\$59.95	\$64.70	\$4.76	7.94%
	600	\$69.13	\$74.64	\$5.51	7.97%
	750	\$82.92	\$89.55	\$6.64	8.00%
	850	\$92.11	\$99.49	\$7.39	8.02%
	1000	\$105.89	\$114.41	\$8.52	8.04%
	1500	\$151.84	\$164.11	\$12.27	8.08%
	2000	\$197.78	\$213.81	\$16.03	8.11%
	3000	\$289.67	\$313.22	\$23.55	8.13%
	4000	\$381.56	\$412.62	\$31.06	8.14%
	5000	\$473.45	\$512.03	\$38.58	8.15%
AVERAGE MONTHLY	250	\$32.88	\$35.46	\$2.58	7.84%
	300	\$36.66	\$39.55	\$2.89	7.89%
	400	\$44.22	\$47.74	\$3.52	7.97%
	500	\$51.77	\$55.92	\$4.15	8.02%
	600	\$59.32	\$64.11	\$4.78	8.07%
	750	\$70.65	\$76.38	\$5.73	8.11%
	850	\$78.21	\$84.57	\$6.36	8.13%
	1000	\$89.54	\$96.85	\$7.31	8.16%
	1500	\$127.31	\$137.77	\$10.46	8.22%
	2000	\$165.08	\$178.69	\$13.62	8.25%
	3000	\$240.61	\$260.54	\$19.92	8.28%
	4000	\$316.15	\$342.38	\$26.23	8.30%
	5000	\$391.69	\$424.23	\$32.54	8.31%

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**RESIDENTIAL TIME OF DAY SERVICE (Overhead) - D02**

On-Peak = 35%

	Energy in kWh	Monthly Bill		Increase	
		Present	Proposed	Amount	Percent
WINTER	250	\$29.93	\$32.64	\$2.71	9.05%
	300	\$33.72	\$36.77	\$3.05	9.05%
	400	\$41.29	\$45.02	\$3.73	9.05%
	500	\$48.86	\$53.28	\$4.42	9.04%
	600	\$56.43	\$61.53	\$5.10	9.04%
	750	\$67.79	\$73.92	\$6.13	9.04%
	850	\$75.36	\$82.17	\$6.81	9.04%
	1000	\$86.72	\$94.55	\$7.84	9.04%
	1500	\$124.58	\$135.83	\$11.25	9.03%
	2000	\$162.44	\$177.11	\$14.67	9.03%
	3000	\$238.16	\$259.66	\$21.51	9.03%
	4000	\$313.87	\$342.22	\$28.35	9.03%
5000	\$389.59	\$424.77	\$35.18	9.03%	
SUMMER	250	\$33.34	\$36.11	\$2.76	8.29%
	300	\$37.81	\$40.93	\$3.12	8.24%
	400	\$46.75	\$50.57	\$3.82	8.17%
	500	\$55.69	\$60.22	\$4.53	8.13%
	600	\$64.63	\$69.86	\$5.23	8.10%
	750	\$78.03	\$84.33	\$6.29	8.06%
	850	\$86.97	\$93.97	\$7.00	8.04%
	1000	\$100.38	\$108.43	\$8.05	8.02%
	1500	\$145.07	\$156.65	\$11.58	7.98%
	2000	\$189.76	\$204.87	\$15.11	7.96%
	3000	\$279.14	\$301.30	\$22.16	7.94%
	4000	\$368.52	\$397.74	\$29.22	7.93%
5000	\$457.90	\$494.17	\$36.27	7.92%	
AVERAGE MONTHLY	250	\$31.07	\$33.80	\$2.73	8.78%
	300	\$35.08	\$38.15	\$3.07	8.76%
	400	\$43.11	\$46.87	\$3.76	8.73%
	500	\$51.14	\$55.59	\$4.45	8.71%
	600	\$59.16	\$64.31	\$5.15	8.70%
	750	\$71.20	\$77.39	\$6.18	8.68%
	850	\$79.23	\$86.10	\$6.87	8.67%
	1000	\$91.27	\$99.18	\$7.91	8.67%
	1500	\$131.41	\$142.77	\$11.36	8.65%
	2000	\$171.54	\$186.36	\$14.82	8.64%
	3000	\$251.82	\$273.54	\$21.73	8.63%
	4000	\$332.09	\$360.72	\$28.64	8.62%
5000	\$412.36	\$447.91	\$35.54	8.62%	

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**RESIDENTIAL TIME OF DAY SERVICE - SPACE HEATING (Overhead) - D02**

On-Peak = 35%

Energy in kWh	Monthly Bill		Increase		
	Present	Proposed	Amount	Percent	
WINTER	250	\$30.77	\$33.18	\$2.42	7.86%
	300	\$34.12	\$36.82	\$2.70	7.91%
	400	\$40.83	\$44.09	\$3.27	8.00%
	500	\$47.53	\$51.37	\$3.83	8.07%
	600	\$54.24	\$58.64	\$4.40	8.11%
	750	\$64.30	\$69.55	\$5.25	8.17%
	850	\$71.00	\$76.82	\$5.82	8.19%
	1000	\$81.06	\$87.73	\$6.67	8.22%
	1500	\$114.59	\$124.10	\$9.50	8.29%
	2000	\$148.13	\$160.46	\$12.33	8.33%
	3000	\$215.19	\$233.19	\$18.00	8.37%
	4000	\$282.25	\$305.92	\$23.67	8.39%
5000	\$349.32	\$378.65	\$29.34	8.40%	
SUMMER	250	\$36.34	\$39.11	\$2.76	7.60%
	300	\$40.81	\$43.93	\$3.12	7.64%
	400	\$49.75	\$53.57	\$3.82	7.68%
	500	\$58.69	\$63.22	\$4.53	7.71%
	600	\$67.63	\$72.86	\$5.23	7.74%
	750	\$81.03	\$87.33	\$6.29	7.76%
	850	\$89.97	\$96.97	\$7.00	7.78%
	1000	\$103.38	\$111.43	\$8.05	7.79%
	1500	\$148.07	\$159.65	\$11.58	7.82%
	2000	\$192.76	\$207.87	\$15.11	7.84%
	3000	\$282.14	\$304.30	\$22.16	7.86%
	4000	\$371.52	\$400.74	\$29.22	7.86%
5000	\$460.90	\$497.17	\$36.27	7.87%	
AVERAGE MONTHLY	250	\$32.63	\$35.16	\$2.53	7.76%
	300	\$36.35	\$39.19	\$2.84	7.81%
	400	\$43.80	\$47.25	\$3.45	7.88%
	500	\$51.25	\$55.32	\$4.06	7.93%
	600	\$58.70	\$63.38	\$4.68	7.97%
	750	\$69.88	\$75.47	\$5.60	8.01%
	850	\$77.33	\$83.54	\$6.21	8.03%
	1000	\$88.50	\$95.63	\$7.13	8.06%
	1500	\$125.75	\$135.95	\$10.19	8.11%
	2000	\$163.00	\$176.26	\$13.26	8.13%
	3000	\$237.51	\$256.89	\$19.39	8.16%
	4000	\$312.01	\$337.53	\$25.52	8.18%
5000	\$386.51	\$418.16	\$31.65	8.19%	

Northern States Power Company  
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**SMALL GENERAL SERVICE**

	Energy in kWh	Monthly Bill		Increase	
		Present	Proposed	Amount	Percent
WINTER	250	\$31.52	\$34.19	\$2.68	8.49%
	300	\$35.42	\$38.43	\$3.01	8.50%
	400	\$43.23	\$46.91	\$3.68	8.51%
	500	\$51.04	\$55.39	\$4.35	8.52%
	600	\$58.85	\$63.87	\$5.02	8.53%
	750	\$70.56	\$76.58	\$6.03	8.54%
	1000	\$90.08	\$97.78	\$7.70	8.55%
	1500	\$129.12	\$140.17	\$11.05	8.56%
	2000	\$168.16	\$182.56	\$14.40	8.56%
	3000	\$246.23	\$267.34	\$21.10	8.57%
	4000	\$324.31	\$352.12	\$27.80	8.57%
5000	\$402.39	\$436.89	\$34.51	8.58%	
SUMMER	250	\$35.15	\$37.90	\$2.75	7.83%
	300	\$39.78	\$42.88	\$3.10	7.80%
	400	\$49.04	\$52.85	\$3.80	7.76%
	500	\$58.30	\$62.81	\$4.51	7.73%
	600	\$67.56	\$72.77	\$5.21	7.71%
	750	\$81.45	\$87.71	\$6.26	7.68%
	1000	\$104.60	\$112.61	\$8.01	7.66%
	1500	\$150.90	\$162.42	\$11.52	7.63%
	2000	\$197.21	\$212.23	\$15.02	7.62%
	3000	\$289.81	\$311.84	\$22.03	7.60%
	4000	\$382.41	\$411.45	\$29.04	7.59%
5000	\$475.02	\$511.07	\$36.05	7.59%	
AVERAGE MONTHLY	250	\$32.73	\$35.43	\$2.70	8.25%
	300	\$36.88	\$39.92	\$3.04	8.25%
	400	\$45.17	\$48.89	\$3.72	8.24%
	500	\$53.46	\$57.86	\$4.40	8.23%
	600	\$61.75	\$66.83	\$5.08	8.23%
	750	\$74.19	\$80.29	\$6.10	8.23%
	1000	\$94.92	\$102.72	\$7.80	8.22%
	1500	\$136.38	\$147.59	\$11.21	8.22%
	2000	\$177.84	\$192.45	\$14.61	8.21%
	3000	\$260.76	\$282.17	\$21.41	8.21%
	4000	\$343.68	\$371.89	\$28.22	8.21%
5000	\$426.60	\$461.62	\$35.02	8.21%	

Northern States Power Company  
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**GENERAL SERVICE (Secondary Voltage)**

Demand in kW	Energy in kWh	Hours	Monthly Bill		Increase	
			Present	Proposed	Amount	Percent
15	3,000	200	\$319.08	\$354.28	\$35.20	11.03%
15	6,000	400	\$478.66	\$523.21	\$44.55	9.31%
15	9,000	600	\$611.24	\$662.14	\$50.90	8.33%
25	5,000	200	\$517.13	\$574.23	\$57.10	11.04%
25	10,000	400	\$783.10	\$855.78	\$72.68	9.28%
25	15,000	600	\$1,004.07	\$1,087.33	\$83.26	8.29%
50	10,000	200	\$1,012.27	\$1,124.11	\$111.84	11.05%
50	20,000	400	\$1,544.21	\$1,687.21	\$143.01	9.26%
50	30,000	600	\$1,986.14	\$2,150.31	\$164.17	8.27%
75	15,000	200	\$1,507.40	\$1,674.00	\$166.59	11.05%
75	30,000	400	\$2,305.31	\$2,518.64	\$213.33	9.25%
75	45,000	600	\$2,968.21	\$3,213.29	\$245.08	8.26%
100	20,000	200	\$2,002.54	\$2,223.88	\$221.34	11.05%
100	40,000	400	\$3,066.41	\$3,350.07	\$283.66	9.25%
100	60,000	600	\$3,950.28	\$4,276.27	\$325.98	8.25%
200	40,000	200	\$3,983.08	\$4,423.41	\$440.33	11.05%
200	80,000	400	\$6,110.82	\$6,675.79	\$564.97	9.25%
200	120,000	600	\$7,878.56	\$8,528.18	\$649.62	8.25%
300	60,000	200	\$5,963.62	\$6,622.93	\$659.32	11.06%
300	120,000	400	\$9,155.23	\$10,001.52	\$846.28	9.24%
300	180,000	600	\$11,806.85	\$12,780.10	\$973.25	8.24%
500	100,000	200	\$9,924.69	\$11,021.99	\$1,097.30	11.06%
500	200,000	400	\$15,244.05	\$16,652.96	\$1,408.91	9.24%
500	300,000	600	\$19,663.41	\$21,283.93	\$1,620.52	8.24%
1,000	200,000	200	\$19,827.38	\$22,019.63	\$2,192.24	11.06%
1,000	400,000	400	\$30,466.10	\$33,281.57	\$2,815.46	9.24%
1,000	600,000	600	\$39,304.82	\$42,543.51	\$3,238.69	8.24%
3,000	600,000	200	\$59,438.15	\$66,010.18	\$6,572.02	11.06%
3,000	1,200,000	400	\$91,354.31	\$99,796.00	\$8,441.69	9.24%
3,000	1,800,000	600	\$117,870.46	\$127,581.83	\$9,711.36	8.24%
5,000	1,000,000	200	\$99,048.92	\$110,000.73	\$10,951.80	11.06%
5,000	2,000,000	400	\$152,242.51	\$166,310.43	\$14,067.92	9.24%
5,000	3,000,000	600	\$196,436.10	\$212,620.14	\$16,184.04	8.24%

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**GENERAL SERVICE (Primary Voltage)**

Demand in kW	Energy in kWh	Hours	Monthly Bill		Increase	
			Present	Proposed	Amount	Percent
15	3,000	200	\$306.93	\$342.25	\$35.32	11.51%
15	6,000	400	\$463.66	\$508.15	\$44.49	9.59%
15	9,000	600	\$593.39	\$644.05	\$50.66	8.54%
25	5,000	200	\$496.88	\$554.18	\$57.30	11.53%
25	10,000	400	\$758.10	\$830.68	\$72.58	9.57%
25	15,000	600	\$974.32	\$1,057.18	\$82.86	8.50%
50	10,000	200	\$971.77	\$1,084.01	\$112.24	11.55%
50	20,000	400	\$1,494.21	\$1,637.01	\$142.81	9.56%
50	30,000	600	\$1,926.64	\$2,090.01	\$163.37	8.48%
75	15,000	200	\$1,446.65	\$1,613.85	\$167.19	11.56%
75	30,000	400	\$2,230.31	\$2,443.34	\$213.03	9.55%
75	45,000	600	\$2,878.96	\$3,122.84	\$243.88	8.47%
100	20,000	200	\$1,921.54	\$2,143.68	\$222.14	11.56%
100	40,000	400	\$2,966.41	\$3,249.67	\$283.26	9.55%
100	60,000	600	\$3,831.28	\$4,155.67	\$324.38	8.47%
200	40,000	200	\$3,821.08	\$4,263.01	\$441.93	11.57%
200	80,000	400	\$5,910.82	\$6,474.99	\$564.17	9.54%
200	120,000	600	\$7,640.56	\$8,286.98	\$646.42	8.46%
300	60,000	200	\$5,720.62	\$6,382.33	\$661.72	11.57%
300	120,000	400	\$8,855.23	\$9,700.32	\$845.08	9.54%
300	180,000	600	\$11,449.85	\$12,418.30	\$968.45	8.46%
500	100,000	200	\$9,519.69	\$10,620.99	\$1,101.30	11.57%
500	200,000	400	\$14,744.05	\$16,150.96	\$1,406.91	9.54%
500	300,000	600	\$19,068.41	\$20,680.93	\$1,612.52	8.46%
1,000	200,000	200	\$19,017.38	\$21,217.63	\$2,200.24	11.57%
1,000	400,000	400	\$29,466.10	\$32,277.57	\$2,811.46	9.54%
1,000	600,000	600	\$38,114.82	\$41,337.51	\$3,222.69	8.46%
3,000	600,000	200	\$57,008.15	\$63,604.18	\$6,596.02	11.57%
3,000	1,200,000	400	\$88,354.31	\$96,784.00	\$8,429.69	9.54%
3,000	1,800,000	600	\$114,300.46	\$123,963.83	\$9,663.36	8.45%
5,000	1,000,000	200	\$94,998.92	\$105,990.73	\$10,991.80	11.57%
5,000	2,000,000	400	\$147,242.51	\$161,290.43	\$14,047.92	9.54%
5,000	3,000,000	600	\$190,486.10	\$206,590.14	\$16,104.04	8.45%

Northern States Power Company  
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**GENERAL TOD SERVICE (Secondary Voltage)**

40% On-Peak  
60% Off-Peak

Demand in kW	Energy in kWh	Hours	Monthly Bill		Increase	
			Present	Proposed	Amount	Percent
15	3,000	200	\$318.90	\$353.46	\$34.55	10.84%
15	6,000	400	\$475.31	\$518.57	\$43.26	9.10%
15	9,000	600	\$604.71	\$653.68	\$48.96	8.10%
25	5,000	200	\$514.84	\$570.87	\$56.02	10.88%
25	10,000	400	\$775.51	\$846.05	\$70.53	9.09%
25	15,000	600	\$991.19	\$1,071.23	\$80.04	8.08%
50	10,000	200	\$1,004.68	\$1,114.38	\$109.70	10.92%
50	20,000	400	\$1,526.03	\$1,664.74	\$138.72	9.09%
50	30,000	600	\$1,957.38	\$2,115.11	\$157.73	8.06%
75	15,000	200	\$1,494.52	\$1,657.90	\$163.37	10.93%
75	30,000	400	\$2,276.54	\$2,483.44	\$206.90	9.09%
75	45,000	600	\$2,923.56	\$3,158.99	\$235.42	8.05%
100	20,000	200	\$1,984.36	\$2,201.41	\$217.05	10.94%
100	40,000	400	\$3,027.06	\$3,302.14	\$275.08	9.09%
100	60,000	600	\$3,889.75	\$4,202.87	\$313.11	8.05%
200	40,000	200	\$3,943.72	\$4,375.47	\$431.75	10.95%
200	80,000	400	\$6,029.11	\$6,576.93	\$547.81	9.09%
200	120,000	600	\$7,754.50	\$8,378.38	\$623.88	8.05%
300	60,000	200	\$5,903.09	\$6,549.53	\$646.45	10.95%
300	120,000	400	\$9,031.17	\$9,851.72	\$820.55	9.09%
300	180,000	600	\$11,619.26	\$12,553.90	\$934.64	8.04%
500	100,000	200	\$9,821.81	\$10,897.66	\$1,075.85	10.95%
500	200,000	400	\$15,035.28	\$16,401.30	\$1,366.01	9.09%
500	300,000	600	\$19,348.76	\$20,904.93	\$1,556.17	8.04%
1,000	200,000	200	\$19,618.62	\$21,767.96	\$2,149.34	10.96%
1,000	400,000	400	\$30,045.57	\$32,775.24	\$2,729.67	9.09%
1,000	600,000	600	\$38,672.52	\$41,782.52	\$3,110.00	8.04%
3,000	600,000	200	\$58,805.85	\$65,249.19	\$6,443.33	10.96%
3,000	1,200,000	400	\$90,086.71	\$98,271.02	\$8,184.31	9.08%
3,000	1,800,000	600	\$115,967.56	\$125,292.86	\$9,325.29	8.04%
5,000	1,000,000	200	\$97,993.09	\$108,730.41	\$10,737.32	10.96%
5,000	2,000,000	400	\$150,127.85	\$163,766.80	\$13,638.95	9.08%
5,000	3,000,000	600	\$193,262.61	\$208,803.20	\$15,540.59	8.04%

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**GENERAL TOD SERVICE (Primary Voltage)**

40% On-Peak  
60% Off-Peak

Demand in kW	Energy in kWh	Hours	Monthly Bill		Increase	
			Present	Proposed	Amount	Percent
15	3,000	200	\$306.75	\$341.43	\$34.67	11.30%
15	6,000	400	\$460.31	\$503.51	\$43.20	9.38%
15	9,000	600	\$586.86	\$635.59	\$48.72	8.30%
25	5,000	200	\$494.59	\$550.82	\$56.22	11.37%
25	10,000	400	\$750.51	\$820.95	\$70.43	9.38%
25	15,000	600	\$961.44	\$1,041.08	\$79.64	8.28%
50	10,000	200	\$964.18	\$1,074.28	\$110.10	11.42%
50	20,000	400	\$1,476.03	\$1,614.54	\$138.52	9.38%
50	30,000	600	\$1,897.88	\$2,054.81	\$156.93	8.27%
75	15,000	200	\$1,433.77	\$1,597.75	\$163.97	11.44%
75	30,000	400	\$2,201.54	\$2,408.14	\$206.60	9.38%
75	45,000	600	\$2,834.31	\$3,068.54	\$234.22	8.26%
100	20,000	200	\$1,903.36	\$2,121.21	\$217.85	11.45%
100	40,000	400	\$2,927.06	\$3,201.74	\$274.68	9.38%
100	60,000	600	\$3,770.75	\$4,082.27	\$311.51	8.26%
200	40,000	200	\$3,781.72	\$4,215.07	\$433.35	11.46%
200	80,000	400	\$5,829.11	\$6,376.13	\$547.01	9.38%
200	120,000	600	\$7,516.50	\$8,137.18	\$620.68	8.26%
300	60,000	200	\$5,660.09	\$6,308.93	\$648.85	11.46%
300	120,000	400	\$8,731.17	\$9,550.52	\$819.35	9.38%
300	180,000	600	\$11,262.26	\$12,192.10	\$929.84	8.26%
500	100,000	200	\$9,416.81	\$10,496.66	\$1,079.85	11.47%
500	200,000	400	\$14,535.28	\$15,899.30	\$1,364.01	9.38%
500	300,000	600	\$18,753.76	\$20,301.93	\$1,548.17	8.26%
1,000	200,000	200	\$18,808.62	\$20,965.96	\$2,157.34	11.47%
1,000	400,000	400	\$29,045.57	\$31,771.24	\$2,725.67	9.38%
1,000	600,000	600	\$37,482.52	\$40,576.52	\$3,094.00	8.25%
3,000	600,000	200	\$56,375.85	\$62,843.19	\$6,467.33	11.47%
3,000	1,200,000	400	\$87,086.71	\$95,259.02	\$8,172.31	9.38%
3,000	1,800,000	600	\$112,397.56	\$121,674.86	\$9,277.29	8.25%
5,000	1,000,000	200	\$93,943.09	\$104,720.41	\$10,777.32	11.47%
5,000	2,000,000	400	\$145,127.85	\$158,746.80	\$13,618.95	9.38%
5,000	3,000,000	600	\$187,312.61	\$202,773.20	\$15,460.59	8.25%

Northern States Power Company  
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**PEAK-CONTROLLED SERVICE (Secondary Voltage)**

**Tier 2 Perf Factor B - No Firm Demand**

Demand in kW	Energy in kWh	Hours	Monthly Bill		Increase	
			Present	Proposed	Amount	Percent
50	10,000	200	\$843.94	\$944.45	\$100.51	11.91%
50	20,000	400	\$1,375.87	\$1,507.54	\$131.67	9.57%
50	30,000	600	\$1,817.81	\$1,970.64	\$152.83	8.41%
75	15,000	200	\$1,254.90	\$1,404.50	\$149.59	11.92%
75	30,000	400	\$2,052.81	\$2,249.14	\$196.33	9.56%
75	45,000	600	\$2,715.71	\$2,943.79	\$228.08	8.40%
100	20,000	200	\$1,665.87	\$1,864.54	\$198.67	11.93%
100	40,000	400	\$2,729.74	\$2,990.74	\$260.99	9.56%
100	60,000	600	\$3,613.62	\$3,916.93	\$303.32	8.39%
150	30,000	200	\$2,487.81	\$2,784.64	\$296.83	11.93%
150	60,000	400	\$4,083.62	\$4,473.93	\$390.32	9.56%
150	90,000	600	\$5,409.42	\$5,863.22	\$453.80	8.39%
200	40,000	200	\$3,309.74	\$3,704.74	\$394.99	11.93%
200	80,000	400	\$5,437.49	\$5,957.13	\$519.64	9.56%
200	120,000	600	\$7,205.23	\$7,809.52	\$604.28	8.39%
300	60,000	200	\$4,953.62	\$5,544.93	\$591.32	11.94%
300	120,000	400	\$8,145.23	\$8,923.52	\$778.28	9.56%
300	180,000	600	\$10,796.85	\$11,702.10	\$905.25	8.38%
400	80,000	200	\$6,597.49	\$7,385.13	\$787.64	11.94%
400	160,000	400	\$10,852.97	\$11,889.90	\$1,036.93	9.55%
400	240,000	600	\$14,388.46	\$15,594.68	\$1,206.22	8.38%
500	100,000	200	\$8,241.36	\$9,225.32	\$983.96	11.94%
500	200,000	400	\$13,560.72	\$14,856.29	\$1,295.57	9.55%
500	300,000	600	\$17,980.08	\$19,487.26	\$1,507.19	8.38%
1,000	200,000	200	\$16,460.72	\$18,426.29	\$1,965.57	11.94%
1,000	400,000	400	\$27,099.44	\$29,688.23	\$2,588.80	9.55%
1,000	600,000	600	\$35,938.15	\$38,950.18	\$3,012.02	8.38%
3,000	600,000	200	\$49,338.15	\$55,230.18	\$5,892.02	11.94%
3,000	1,200,000	400	\$81,254.31	\$89,016.00	\$7,761.69	9.55%
3,000	1,800,000	600	\$107,770.46	\$116,801.83	\$9,031.36	8.38%
5,000	1,000,000	200	\$82,215.59	\$92,034.06	\$9,818.47	11.94%
5,000	2,000,000	400	\$135,409.18	\$148,343.77	\$12,934.59	9.55%
5,000	3,000,000	600	\$179,602.77	\$194,653.48	\$15,050.71	8.38%

Northern States Power Company  
Electric Utility - North Dakota Retail Jurisdiction  
Test Year Ending December 31, 2013  
**Comparison Of Bills At Present & Proposed Rates**

Case No. PU-12-\_\_\_\_\_  
Exhibit No. \_\_\_\_\_(Notice)  
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**PEAK-CONTROLLED TOD SERVICE (Secondary Voltage)**

40% On-Peak

60% Off-Peak

Tier 2 Perf Factor B - No Firm Demand

Demand in kW	Energy in kWh	Hours	Monthly Bill		Increase	
			Present	Proposed	Amount	Percent
50	10,000	200	\$836.35	\$934.71	\$98.37	11.76%
50	20,000	400	\$1,357.70	\$1,485.08	\$127.38	9.38%
50	30,000	600	\$1,789.04	\$1,935.44	\$146.40	8.18%
75	15,000	200	\$1,242.02	\$1,388.40	\$146.37	11.79%
75	30,000	400	\$2,024.04	\$2,213.94	\$189.90	9.38%
75	45,000	600	\$2,671.06	\$2,889.49	\$218.42	8.18%
100	20,000	200	\$1,647.70	\$1,842.08	\$194.38	11.80%
100	40,000	400	\$2,690.39	\$2,942.81	\$252.42	9.38%
100	60,000	600	\$3,553.09	\$3,843.53	\$290.45	8.17%
150	30,000	200	\$2,459.04	\$2,749.44	\$290.40	11.81%
150	60,000	400	\$4,023.09	\$4,400.53	\$377.45	9.38%
150	90,000	600	\$5,317.13	\$5,751.63	\$434.50	8.17%
200	40,000	200	\$3,270.39	\$3,656.81	\$386.42	11.82%
200	80,000	400	\$5,355.78	\$5,858.26	\$502.48	9.38%
200	120,000	600	\$7,081.17	\$7,659.72	\$578.55	8.17%
300	60,000	200	\$4,893.09	\$5,471.53	\$578.45	11.82%
300	120,000	400	\$8,021.17	\$8,773.72	\$752.55	9.38%
300	180,000	600	\$10,609.26	\$11,475.90	\$866.64	8.17%
400	80,000	200	\$6,515.78	\$7,286.26	\$770.48	11.82%
400	160,000	400	\$10,686.56	\$11,689.17	\$1,002.61	9.38%
400	240,000	600	\$14,137.34	\$15,292.08	\$1,154.74	8.17%
500	100,000	200	\$8,138.48	\$9,100.99	\$962.51	11.83%
500	200,000	400	\$13,351.95	\$14,604.63	\$1,252.68	9.38%
500	300,000	600	\$17,665.43	\$19,108.27	\$1,442.84	8.17%
1,000	200,000	200	\$16,251.95	\$18,174.63	\$1,922.68	11.83%
1,000	400,000	400	\$26,678.90	\$29,181.91	\$2,503.00	9.38%
1,000	600,000	600	\$35,305.85	\$38,189.19	\$2,883.33	8.17%
3,000	600,000	200	\$48,705.85	\$54,469.19	\$5,763.33	11.83%
3,000	1,200,000	400	\$79,986.71	\$87,491.02	\$7,504.31	9.38%
3,000	1,800,000	600	\$105,867.56	\$114,512.86	\$8,645.29	8.17%
5,000	1,000,000	200	\$81,159.76	\$90,763.74	\$9,603.98	11.83%
5,000	2,000,000	400	\$133,294.52	\$145,800.14	\$12,505.62	9.38%
5,000	3,000,000	600	\$176,429.27	\$190,836.53	\$14,407.26	8.17%

Northern States Power Company  
Electric Utility - North Dakota Retail Jurisdiction  
Test Year Ending December 31, 2013  
**Comparison Of Bills At Present & Proposed Rates**

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**TIER 1 ENERGY-CONTROLLED RIDER (Secondary Voltage)**

Perf Factor C - No Firm Demand

40% On-Peak  
60% Off-Peak

Demand in kW	Energy in kWh	Hours	Monthly Bill		Increase	
			Present	Proposed	Amount	Percent
50	10,000	200	\$763.15	\$861.41	\$98.27	12.88%
50	20,000	400	\$1,266.30	\$1,396.98	\$130.68	10.32%
50	30,000	600	\$1,679.44	\$1,832.54	\$153.10	9.12%
75	15,000	200	\$1,132.22	\$1,278.45	\$146.22	12.91%
75	30,000	400	\$1,886.94	\$2,081.79	\$194.85	10.33%
75	45,000	600	\$2,506.66	\$2,735.14	\$228.47	9.11%
100	20,000	200	\$1,501.30	\$1,695.48	\$194.18	12.93%
100	40,000	400	\$2,507.59	\$2,766.61	\$259.02	10.33%
100	60,000	600	\$3,333.89	\$3,637.73	\$303.85	9.11%
150	30,000	200	\$2,239.44	\$2,529.54	\$290.10	12.95%
150	60,000	400	\$3,748.89	\$4,136.23	\$387.35	10.33%
150	90,000	600	\$4,988.33	\$5,442.93	\$454.60	9.11%
200	40,000	200	\$2,977.59	\$3,363.61	\$386.02	12.96%
200	80,000	400	\$4,990.18	\$5,505.86	\$515.68	10.33%
200	120,000	600	\$6,642.77	\$7,248.12	\$605.35	9.11%
300	60,000	200	\$4,453.89	\$5,031.73	\$577.85	12.97%
300	120,000	400	\$7,472.77	\$8,245.12	\$772.35	10.34%
300	180,000	600	\$9,951.66	\$10,858.50	\$906.84	9.11%
400	80,000	200	\$5,930.18	\$6,699.86	\$769.68	12.98%
400	160,000	400	\$9,955.36	\$10,984.37	\$1,029.01	10.34%
400	240,000	600	\$13,260.54	\$14,468.88	\$1,208.34	9.11%
500	100,000	200	\$7,406.48	\$8,367.99	\$961.51	12.98%
500	200,000	400	\$12,437.95	\$13,723.63	\$1,285.68	10.34%
500	300,000	600	\$16,569.43	\$18,079.27	\$1,509.84	9.11%
1,000	200,000	200	\$14,787.95	\$16,708.63	\$1,920.68	12.99%
1,000	400,000	400	\$24,850.90	\$27,419.91	\$2,569.00	10.34%
1,000	600,000	600	\$33,113.85	\$36,131.19	\$3,017.33	9.11%
3,000	600,000	200	\$44,313.85	\$50,071.19	\$5,757.33	12.99%
3,000	1,200,000	400	\$74,502.71	\$82,205.02	\$7,702.31	10.34%
3,000	1,800,000	600	\$99,291.56	\$108,338.86	\$9,047.29	9.11%
5,000	1,000,000	200	\$73,839.76	\$83,433.74	\$9,593.98	12.99%
5,000	2,000,000	400	\$124,154.52	\$136,990.14	\$12,835.62	10.34%
5,000	3,000,000	600	\$165,469.27	\$180,546.53	\$15,077.26	9.11%

**ROE = 5.35%**  
**Deficiency = \$16,900**  
**% Increase = 9.25%**  
**Required ROE = 10.60%**

**Case No. PU-12-\_\_\_\_**  
**Exhibit\_\_\_\_(Notice)**  
**Schedule 5**  
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**Northern States Power Company (ND)**  
**Electric Utility - North Dakota Retail Jurisdiction**  
**Cost of Service Study**  
**Proposed 2013 Test Year**

**Summary Reports**

**December 2012**

Northern States Power Company (ND)  
Electric Utility - North Dakota Retail Jurisdiction  
Cost of Service Study  
Proposed 2013 Test Year

(Dollars in Thousands)

Rate Base Summary

	<u>Total Company Electric</u>			<u>ND 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	14,512,422	15,975,443	15,243,933	827,530	914,414	870,972	13,684,892	15,061,029	14,372,961
2 Depreciation Reserve	<u>(7,025,573)</u>	<u>(7,401,268)</u>	<u>(7,213,421)</u>	<u>(407,853)</u>	<u>(431,326)</u>	<u>(419,589)</u>	<u>(6,617,720)</u>	<u>(6,969,942)</u>	<u>(6,793,832)</u>
3 Net Utility Plant	7,486,849	8,574,175	8,030,512	419,677	483,088	451,383	7,067,172	8,091,087	7,579,129
4 C.W.I.P.	35,107	31,610	33,359	2,163	1,912	2,037	32,944	29,698	31,322
5 Accumulated Deferred Taxes	(1,589,312)	(1,816,096)	(1,702,704)	(86,356)	(99,212)	(92,784)	(1,502,956)	(1,716,883)	(1,609,920)
Other Rate Base:									
6 Cash Working Capital	(46,175)	(46,175)	(46,175)	(926)	(926)	(926)	(45,248)	(45,248)	(45,248)
7 Materials & Supplies	125,754	125,754	125,754	7,613	7,613	7,613	118,141	118,141	118,141
8 Fuel Inventory	90,495	90,495	90,495	5,899	5,899	5,899	84,596	84,596	84,596
9 Non-Plant Assets & Liab	(46,907)	(12,429)	(29,668)	(2,860)	(758)	(1,809)	(44,047)	(11,671)	(27,859)
10 Prepays & Other	91,497	108,869	100,183	5,704	6,766	6,235	85,793	102,103	93,948
<b>11 Total Rate Base</b>	<b>6,147,308</b>	<b>7,056,204</b>	<b>6,601,756</b>	<b>350,913</b>	<b>404,381</b>	<b>377,648</b>	<b>5,796,395</b>	<b>6,651,822</b>	<b>6,224,109</b>

Northern States Power Company (ND)  
Electric Utility - North Dakota Retail Jurisdiction  
Cost of Service Study  
Proposed 2013 Test Year

(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	3,049,972	182,724	2,867,248
2	CIP Adjustment to Program Costs	0	0	0
3	Interdepartmental	540	0	540
4	Other Operating	736,136	45,502	690,634
5	Gross Earnings Tax	0	0	0
6	<b>Total Operating Revenues</b>	<b>3,786,648</b>	<b>228,226</b>	<b>3,558,422</b>
<b><u>Expenses</u></b>				
Operating Expenses:				
7	Fuel & Purchased Energy	1,278,735	82,971	1,195,764
8	Power Production	755,534	46,221	709,313
9	Transmission	232,973	14,031	218,942
10	Distribution	110,834	6,763	104,071
11	Customer Accounting	57,725	4,286	53,439
12	Customer Service & Information	36,890	457	36,433
13	Sales, Econ Dvlp & Other	309	173	136
14	Administrative & General	233,106	14,822	218,284
15	<b>Total Operating Expenses</b>	<b>2,706,106</b>	<b>169,724</b>	<b>2,536,382</b>
16	Depreciation	371,234	22,563	348,671
17	Amortization	23,100	373	22,727
Taxes:				
18	Property	167,591	7,940	159,651
19	Gross Earnings	0	0	0
20	Deferred Income Tax & ITC	224,372	12,760	211,612
21	State & Federal Income (see Page 3)	(105,791)	(6,481)	(99,310)
22	Payroll & Other	31,388	1,931	29,457
23	<b>Total Taxes</b>	<b>317,560</b>	<b>16,151</b>	<b>301,410</b>
24	<b>Total Expenses</b>	<b>3,418,000</b>	<b>208,811</b>	<b>3,209,189</b>
25	AFUDC	0	0	0
26	<b>Total Operating Income</b>	<b>368,648</b>	<b>19,415</b>	<b>349,233</b>

**Income Tax Summary**

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>
<b><u>Income Before Taxes</u></b>			
1	Total Operating Revenues	3,786,648	228,226
2	less: Total Operating Expenses	(2,706,106)	(169,724)
3	Book Depreciation & Amortization	(394,334)	(22,936)
4	Taxes (Other Than Current Income)	(423,351)	(22,631)
5	<b>Total Before Tax Book Income</b>	<b>262,857</b>	<b>12,934</b>
<b><u>Tax Additions</u></b>			
6	Book Depreciation	371,234	22,563
7	Deferred Income Taxes & ITC	224,372	12,760
8	Nuclear Fuel Burn (ex D&D)	120,368	7,249
9	Nuclear Outage Accounting	74,486	4,664
10	Avoided Tax Interest	52,435	3,051
11	Open Line	0	0
12	Open Line	0	0
13	Open Line	0	0
14	Open Line	0	0
15	Open Line	0	0
16	Other Book Additions	0	0
17	<b>Total Tax Additions</b>	<b>842,895</b>	<b>50,288</b>
<b><u>Tax Deductions</u></b>			
18	Debt Interest Expense	153,821	8,799
19	Tax Depreciation & Removal	1,122,833	69,100
20	Manufacture Production Deduction	0	0
21	Open	0	0
22	Open	0	0
23	Open	0	0
24	Other Tax/Book Timing Differences	36,449	2,223
25	Net Preferred Stock Deduction	0	0
26	<b>Total Tax Deductions</b>	<b>1,313,102</b>	<b>80,122</b>
27	<b>State Taxable Income</b>	<b>(207,350)</b>	<b>(16,900)</b>
28	State Income Tax Rate	9.07%	5.15%
29	State Taxes before Credits	(18,797)	(870)
30	State Credits	0	0
31	<b>Total State Income Taxes</b>	<b>(18,797)</b>	<b>(17,927)</b>
32	<b>Federal Taxable Income</b>	<b>(188,553)</b>	<b>(16,029)</b>
33	Federal Income Tax Rate	35.00%	35.00%
34	Federal Tax before Credits	(65,994)	(5,610)
35	Federal Tax Credits	21,000	0
36	<b>Total Federal Income Taxes</b>	<b>(86,994)</b>	<b>(5,610)</b>
37	<b>Total Federal &amp; State Income Taxes</b>	<b>(105,791)</b>	<b>(99,310)</b>

Northern States Power Company (ND)  
Electric Utility - North Dakota Retail Jurisdiction  
Cost of Service Study  
Proposed 2013 Test Year

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**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	5.1400%	44.9600%	2.3100%	State of North Dakota Tax rate	5.15%
2	Short Term Debt	0.7500%	2.4800%	0.0200%	Federal Statutory Tax rate	35.00%
3	Preferred Stock	0.0000%	0.0000%	0.0000%	Federal Effective Tax Rate (1-State Rate*Fed Rate)	33.20%
4	Common Equity	10.6000%	52.5600%	5.5700%	<b>Total North Dakota Composite Tax Rate</b>	<b>38.35%</b>
5	<b>Required Rate of Return</b>			<b>7.9000%</b>	<b>Total Corporate Composite Tax Rate</b>	<b>40.89%</b>

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>
<b><u>Rate of Return (ROR)</u></b>			
6	Total Operating Income	368,648	19,415
7	Total Average Rate Base	6,601,756	377,648
8	<b>ROR (Operating Income / Rate Base)</b>	<b>5.58%</b>	<b>5.14%</b>

<b><u>Return on Equity (ROE)</u></b>			
9	Total Operating Income	368,648	19,415
10	Debt Interest (Rate Base * Weighted Debt Cost)	(153,821)	(8,799)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0
12	Earnings Available for Common	214,827	10,616
13	Equity Rate Base ( Rate Base * Equity Ratio)	3,469,883	198,492
14	<b>ROE (Earnings for Common / Equity Rate Base)</b>	<b>6.19%</b>	<b>5.35%</b>

<b><u>Revenue Deficiency</u></b>			
15	Require Operating Income (Rate Base * Required Return)	521,539	29,834
16	Operating Income	368,648	19,415
17	Operating Income Deficiency	152,891	10,419
18	Revenue Conversion Factor ( 1/(1-Composite Tax Rate) )	1.69184	1.62201
19	<b>Revenue Deficiency (Income Deficiency * Conversion Factor)</b>	<b>258,667</b>	<b>16,900</b>

<b><u>Total Retail Revenue Requirements</u></b>			
20	Retail Related Revenues	3,050,512	182,724
21	Revenue Deficiency	258,667	16,900
22	<b>Total Retail Revenue Requirements</b>	<b>3,309,179</b>	<b>199,624</b>

23	<b><u>Percentage Increase (Decrease)</u></b>	<b>8.48%</b>	<b>9.25%</b>	<b>8.43%</b>
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Northern States Power Company (ND)  
Electric Utility - North Dakota Retail Jurisdiction  
Cost of Service Study  
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(Dollars in Thousands)

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**Rate Base Detail - Cash Working Capital**

		<u>Total Company Electric</u>		<u>ND Retail Electric</u>		<u>All Other</u>			
<u>Expenses</u>									
<u>Includable Expenses</u>	<u>Lead Days</u>	<u>Dollars</u>	<u>Dollar x Days</u>	<u>Dollars</u>	<u>Dollar x Days</u>	<u>Dollars</u>	<u>Dollar x Days</u>		
<u>Fuel Expenses</u>									
1	Coal & Rail Transport	18.09	326,178	5,900,560	21,263	384,648	304,915	5,515,912	
2	Gas for Generation	37.01	122,911	4,548,936	8,012	296,524	114,899	4,252,412	
3	Oil	19.40	41	795	3	58	38	737	
4	Nuclear & EOL	0.00	108,580	0	7,137	0	101,443	0	
5	Nuclear Disposal	76.13	11,787	897,344	710	54,052	11,077	843,292	
6			569,497	11,347,636	31,125	735,282	532,372	10,612,354	
<u>Purchased Power</u>									
7	Purchases	33.09	796,126	26,343,809	50,896	1,684,149	745,230	24,659,661	
8	Interchange	38.21	133,505	5,101,226	8,143	311,144	125,362	4,790,082	
			929,631	31,445,035	59,039	1,995,293	870,592	29,449,743	
<u>Labor &amp; Related Costs</u>									
9	Regular Payroll	11.89	385,032	4,578,030	23,893	284,088	361,139	4,293,943	
10	Incentive Compensation	252.18	26,337	6,641,665	1,612	406,514	24,725	6,235,151	
11	Pension & Benefits	16.80	93,851	1,578,697	5,843	98,162	88,008	1,478,534	
12	Subtotal Labor & Related		505,220	12,796,392	31,348	788,764	473,872	12,007,628	
13									
14	All Other Operating Expenses	29.21	701,758	20,498,351	42,212	1,233,013	659,546	19,265,339	
15	Property Tax	355.99	167,591	59,660,720	7,940	2,826,561	159,651	56,834,159	
16	Employer's Payroll Taxes	28.44	31,388	892,675	1,931	54,918	29,457	837,757	
17	Gross Earnings Tax	53.06	0	0	0	0	0	0	
18	Federal Income Tax	36.75	(86,994)	(3,197,014)	(5,610)	(206,176)	(81,383)	(2,990,838)	
19	State Income Tax	36.75	(18,797)	(690,806)	(870)	(31,990)	(17,927)	(658,816)	
20	State Sales Tax Customer Billings	28.99	148,826	4,314,466	0	0	148,826	4,314,466	
21	Total Expenses	46.49	2,948,120	137,067,455	42.72	173,114	7,395,665	46.73	2,775,056
22	Net Annual Expense Amount			375,527		20,262		355,265	
<u>Revenues</u>									
23	Computer Billing	100.00%	41.28	3,049,972	125,902,844	182,724	7,542,847	2,867,248	118,359,997
24	Hand Billed	0.00%	41.28	0	0	0	0	0	0
25	Retail Revenue Adjustments	0.00	0	0	0	0	0	0	
26	Interdepartmental	0.00	540	0	0	0	540	0	
27	Late Payment	0.00	4,684	0	278	0	4,406	0	
28	Connect and Trouble Charges	41.28	2,235	92,261	274	11,311	1,961	80,950	
29	CIP Incentive	0.00	210	0	0	0	210	0	
30	Rentals	-11.29	4,205	(47,474)	268	(3,026)	3,937	(44,449)	
31	Interchange Revenues	38.21	441,961	16,887,330	27,615	1,055,169	414,346	15,832,161	
32	Sales for Resale	41.06	141,870	5,825,182	9,115	374,262	132,755	5,450,920	
33	Production Associated Revenues	41.06	6,459	265,207	421	17,286	6,038	247,920	
34	MISO	14.00	1,659	23,226	100	1,400	1,559	21,826	
35	Point to Point Firm	41.06	38,519	1,581,590	2,320	95,259	36,199	1,486,331	
36	Services & Facilities	41.06	8,783	360,630	523	21,474	8,260	339,156	
37	Ancillary	41.06	80,738	3,315,102	4,863	199,675	75,875	3,115,428	
38	Distribution Associated Revenues	41.28	0	0	0	0	0	0	
39	Other	41.28	10,489	432,986	95	3,922	10,394	429,064	
40	JOA - Rev fr/to PSC	41.06	(5,676)	(233,057)	(370)	(15,192)	(5,306)	(217,864)	
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	40.78	3,786,648	154,405,827	40.77	228,226	9,304,387	40.78	3,558,422
45	Net Annual Amount			423,030		25,491		397,538	
46	Expense / Revenue Factor			0.7786		0.7585			
47	Allocated Revenue Amount			329,353		19,336			
48	Net Cash Working Capital	Page 1 - Line 6		(46,175)		(926)		(45,248)	

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Schedule DM-1

REVENUE REQUIREMENT  
 (\$000's)

	Updated Company Position Present Rates	Adjustments	Advocacy Staff	References
1 Pro Forma Rate Base	\$ 375,678	\$ (53,164)	\$ 322,514	Schedule DM-3
2 Rate of Return	7.90%	-0.76%	7.14%	Schedule DM-2
3 Income Requirement	\$ 29,679	\$ (6,658)	\$ 23,021	
4 Pro Forma Income	\$ 19,802	\$ 4,506	\$ 24,308	Schedule DM-10
5 Income Deficiency	\$ 9,877	\$ (11,164)	\$ (1,287)	
6 Revenue Conversion Factor (1)	1.62201		1.62201	(1)
7 Rate Increase	\$ 16,020	\$ (18,108)	\$ (2,088)	
8 Retail Related Revenue/Present Rates	\$ 182,724		\$ 177,077	Schedule DM-10
9 % Increase	8.77%	-9.95%	-1.18%	

1 Revenue Conversion Factor is calculated as below:

Federal Tax Rate: 35.00%  
 State Tax Rate: 5.15%  
 Federal Effective Rate: (1-.0515\*.35) 33.1975%  
 Composite Tax Rate 38.3475%  
 Rounded to 38.3480%

1/1-.38348=1.62201

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Schedule DM-2

OVERALL RATE OF RETURN

Company Proposal:

	Ratios	Cost Rates	Weighted Cost Rates	References
Long Term Debt	44.960%	5.140%	2.311%	
Short Term Debt	2.480%	0.750%	0.019%	
Preferred Stock	0.000%	0.000%	0.000%	
Common Equity	52.560%	10.600%	5.571%	
Total Cost of Capital	100.000%		7.901%	

Advocacy Staff:

Long Term Debt	45.240%	5.140%	2.325%	
Short Term Debt	1.330%	0.360%	0.005%	
Preferred Stock	0.000%	0.000%	0.000%	
Common Equity	53.420%	9.000%	4.808%	
Total Cost of Capital	99.990%		7.138%	

RATE BASE  
 (\$000's)

	(1) Proposed- Avg. Balance	Adjustments	Advocacy Staff	References
1 Plant Investment	\$ 869,185	\$ (120,402)	\$ 748,783	Schedule DM-4
2 Reserve for Depreciation	\$ 419,306	\$ -	\$ 361,630	Schedule DM-5
3 Net Utility Plant in Service	\$ 449,879	\$ (120,402)	\$ 387,153	
4 Utility Plant Held for Future Use	\$ -	\$ -	\$ -	
5 Construction Work in Progress	\$ 2,037	\$ (310)	\$ 1,727	Schedule DM-6
Less:				
6 Accumulated Deferred Income Taxes	\$ 92,805	\$ (13,733)	\$ 79,072	Schedule DM-7
7 Cash Working Capital	\$ (1,080)	\$ 152	\$ (928)	Schedule DM-8
8 Net Investment In Utility Plant	\$ 358,031	\$ (49,150)	\$ 308,881	
Other Rate Base Items:				
9 Materials and Supplies	\$ 7,613	\$ -	\$ 7,613	Schedule DM-9
19 Fuel Inventory	\$ 5,899	\$ -	\$ 5,899	Schedule DM-9
11 Non-Plant Assets & Liabilities	\$ (2,100)	\$ -	\$ (2,100)	Schedule DM-9
12 Prepayments and Other	\$ 6,235	\$ -	\$ 6,235	Schedule DM-9
13 Total Average Rate Base	\$ 375,678	\$ (49,150)	\$ 326,528	

(1) Per Exhibit AEH-1, Sch 8 Updated pg. 2 of 6

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Schedule DM-4

RECOMMENDED PLANT IN SERVICE  
 (\$000's)

1	Average Plant in Service Balance: 2011	\$	742,545
2	Average Plant in Service Balance: 2012	\$	780,660
3	Adjustments to Plant in 2013:	\$	78,384
4	Subtotal	\$	<u>859,044</u>
5	Allocation Factor of 87.1% (T&D Allocations)		87.10%
6	Recommended Beginning Balance	\$	<u>748,227</u>
7	Adjustments: Forecasted Updates / Rate Case Adjustments		
8	Monticello License Discovery	\$	(1,337)
9	Projects out of 2013 Discovery	\$	(579)
10	AFUDC Correction Discovery	\$	132
11	AFUDC MISO Correction Discovery	\$	(3)
12	Nuclear Fuel Update	\$	243
13	Transmission - Bemidji CapX2020	\$	1,906
14	Transmission - Brookings CapX2020	\$	<u>194</u>
15	Total Adjustments to Plant	\$	<u>556</u>
16	Recommended Plant in Service Balance 2013	\$	<u><u>748,783</u></u>

References

Pg. E-2, 2011 Annual Report to the NDPSC  
 Pg. E-2, 2012 Annual Report to the NDPSC

Data Request NDPSC-5-20, p 46  
 (2013 expenditures x .051121%)NDPSC 5-086

Table KRP-1

Exhibit AEH-1, Schedule 5, page 1 of 1  
 Exhibit AEH-1, Schedule 5, page 1 of 1  
 Exhibit AEH-1, Schedule 5, page 1 of 1  
 Exhibit AEH-1, Schedule 5, page 1 of 1  
 Exhibit AEH-1, Schedule 5, page 1 of 1  
 WP-A1  
 WP-A2

RECOMMENDED ACCUMULATED DEPRECIATION BALANCE  
 (\$000's)

	<u>Advocacy Staff</u>	<u>References</u>
1 Avg. Depr. Reserve Bal. as of December 31, 2011	\$ 364,662	ND Annual Report 2010
2 Avg. Depr. Reserve Bal. as of December 31, 2012	\$ 379,380	ND Annual Report 2011
3 Beginning Bal. Depr. Reserve 2013 (unadjusted)	\$ 418,885	
Ending Bal. Depr. Reserve 2013	\$ 419,306	
Average	\$ 419,096	
% to Average Plant in Service balance of \$869,185,000 (Co. Proposed)	48.22%	
% to Average Plant in Service balance of \$859,044,000 (Recommended)	\$ 414,231	
4 Allocation Factor of 87.2%	87.20%	Table KRP-1
5 Recommended Beginning Balance	<u>\$ 361,209</u>	
Proposed Adjustments:		
6 Nuclear Fuel Updates	\$ 25	AEH-1 Sch 5
7 Production Remaining Life	\$ (127)	AEH-1 Sch 5
8 Black Dog Removal//Remediation	\$ -	AEH-1 Sch 5
9 Monticello License Discovery	\$ (28)	AEH-1 Sch 5
10 Projects Out of 2013 Discovery	\$ 2	AEH-1 Sch 5
11 AFUDC Correction Discovery	\$ 2	AEH-1 Sch 5
12 Sherco 3 Discovery	\$ (11)	AEH-1 Sch 5
13 Bemidji CapX2020	\$ 40	AEH-1 Sch 5
14 Brookings CapX2020	\$ (3)	AEH-1 Sch 5
15 2012 Depreciation Study	\$ 521	AEH-1 Sch 5
16 Total Additions	<u>\$ 421</u>	
17 Total Recommended Avg. Depr. Reserve Bal. as of December 31, 2013	<u><u>\$ 361,630</u></u>	

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Schedule DM-6

RECOMMENDED CONSTRUCTION WORK IN PROGRESS ( CWIP )  
(\$000's)

References

1	Average CWIP Balance as of December 31, 2012	\$	2,936	
2	Company CWIP Balance as of December 31, 2013	\$	<u>2,037</u>	Exhibit AEH-1 Schedule 5, page 1 of 1 update
3	Allocation Factor of 84.8%		<u>84.80%</u>	Table KRP-1
4	Recommended CWIP Balance as of December 31, 2013	\$	<u><u>1,727</u></u>	

RECOMMENDED ACCUMULATED DEFERRED INCOME TAXES

		(\$000's) Updated Company	References
1	Average ADIT Balance as of December 31, 2011	\$ 68,127	NDPSC-1-017 (2011)
2	Average ADIT Balance as of December 31, 2012	\$ 79,680	NDPSC-1-017 (2012)
3	Proposed Avg. ADIT Balance as of December 31, 2013 (unadj.)	<u>\$ 90,835</u>	AEH-1, Schedule 5, page 1 of 1
4	Allocation Factor of 87.10%	<u>87.10%</u>	Table KRP-1
5	Recommended Beginning Balance (Unadjusted)	<u>\$ 79,117</u>	
Adjustments:			
6	Average ADIT Balance as of December 31, 2012		
7	Bemidji Capx2020	\$ 706	AEH-1, Schedule 5, page 1 of 1
8	Brookings CapX2020	\$ 26	AEH-1, Schedule 5, page 1 of 1
9	Nuclear Fuel Updates	\$ (12)	AEH-1, Schedule 5, page 1 of 1
10	2012 Depreciation Study	\$ (213)	AEH-1, Schedule 5, page 1 of 1
11	Production Remaining Life	\$ 52	AEH-1, Schedule 5, page 1 of 1
12	Black Dog Removal/Remediation	\$ -	AEH-1, Schedule 5, page 1 of 1
13	AFUDC Correction	\$ (8)	AEH-1, Schedule 5, page 1 of 1
14	AFUDC MISO Correction Discovery	\$ (3)	AEH-1, Schedule 5, page 1 of 1
15	Monticello License Discovery	\$ (2)	AEH-1, Schedule 5, page 1 of 1
16	Projects Out of 2013 Discovery	\$ 51	AEH-1, Schedule 5, page 1 of 1
17	Sherco 3 Discovery	\$ 5	AEH-1, Schedule 5, page 1 of 1
18	Net Operating Loss	\$ 1,368	AEH-1, Schedule 5, page 1 of 1
19	Company Proposed ADIT Balance Updated	<u>\$ 81,087</u>	
Average beginning ADIT to total UPIS: 90,835/869,630 = 10.45%			
Average ending ADIT to total UPIS: 92,805/869,185 = 10.67%			
Average of the two: 10.56%			
20	Recommended UPIS	\$ 748,783	Schedule DM-4
21	Average ADIT to total UPIS	<u>10.56%</u>	
22	Recommended ADIT balance	<u>\$ 79,072</u>	Schedule DM-3

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Schedule DM-8

CASH WORKING CAPITAL  
(\$000's)

Reference

1	Cash Working Capital - 2012 Annual Report	\$	-
2	Cash Working Capital - Proposed	\$	(1,080)
		\$	(1,080)
3	Recommended Cash Working Capital	\$	<u>(883)</u>

Exhibit AEH-1, Schedule 8, Updated  
Page 6 of 6, updated 6/6/13

Exhibit AEH-1, Schedule 3  
Page 6 of 6 (DM CWC) Attachment

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Revised  
Schedule DM-8

CASH WORKING CAPITAL  
(\$000's)

Reference

1	Cash Working Capital - 2012 Annual Report	\$	-
2	Cash Working Capital - Proposed	\$	(1,080)
		\$	(1,080)
3	Recommended Cash Working Capital	\$	<u>(928)</u>

Exhibit AEH-1, Schedule 8, Updated  
Page 6 of 6, updated 6/6/13

Exhibit AEH-1, Schedule 3  
Page 6 of 6 (DM CWC) Attachment

(Dollars in Thousands)

Rate Base Detail - Cash Working Capital

DM-8 (Attachment)

Expenses	Lead Days	Total Company Electric		ND Retail Electric		All Other				
		Dollars	Dollar x Days	Dollars	Dollar x Days	Dollars	Dollar x Days			
<b>Fuel Expenses</b>										
1	Coal & Rail Transport	21.08	344,376	7,259,446	21,420	451,534	322,956	6,807,912		
2	Gas for Generation	38.45	103,070	3,963,042	6,411	246,503	96,659	3,716,539		
3	Oil	22.51	2,413	54,317	150	3,377	2,263	50,940		
4	Nuclear & EOL	0.00	100,902	0	6,330	0	94,572	0		
5	Nuclear Disposal	76.00	11,471	871,796	660	50,160	10,811	821,636		
6			562,232	12,148,600	32,131	751,573	527,261	11,397,027		
<b>Purchased Power</b>										
7	Purchases	28.12	875,869	24,629,436	35,194	989,655	840,675	23,639,781		
8	Interchange	38.21	124,334	4,750,802	7,242	276,717	117,092	4,474,085		
			1,000,203	29,380,238	42,436	1,266,372	957,767	28,113,866		
<b>Labor &amp; Related Costs</b>										
9	Regular Payroll	12.31	377,411	4,645,929	22,518	277,197	354,893	4,368,733		
10	Incentive Compensation	255.05	19,953	5,089,013	0	0	19,953	5,089,013		
11	Pension & Benefits	19.20	70,563	1,354,810	4,201	80,659	66,362	1,274,150		
12	Subtotal Labor & Related		467,927	11,089,752	26,719	357,856	441,208	10,731,896		
13										
14	All Other Operating Expenses	35.01	612,257	21,435,118	44,559	1,560,011	567,698	19,875,107		
15	Property Tax	356.72	123,651	44,108,785	8,114	2,894,426	115,537	41,214,359		
16	Employer's Payroll Taxes	26.56	30,956	822,191	1,819	48,313	29,137	773,879		
17	Gross Earnings Tax	51.98	0	0	0	0	0	0		
18	Federal Income Tax	37.75	(11,597)	(437,792)	(1,863)	(70,328)	(9,734)	(367,464)		
19	State Income Tax	37.75	1,984	74,897	(289)	(10,910)	2,273	85,807		
20	State Sales Tax Customer Billings	35.73	0	0	0	0	0	0		
21	Total Expenses	42.55	2,787,613	118,621,789	44.25	153,626	6,797,312	42.50	2,631,147	111,824,477
22	Net Annual Expense Amount			324,991			18,623		306,368	
<b>Revenues</b>										
23	Computer Billing	100.00%	42.85	3,111,896	133,350,967	177,077	7,588,104	2,934,819	125,762,864	
24	Hand Billed	0.00%	43.07	0	0	0	0	0	0	
25	Retail Revenue Adjustments		0.00	0	0	0	0	0	0	
26	Interdepartmental		0.00	548	0	0	0	548	0	
27	Late Payment		0.00	4,932	0	0	0	4,932	0	
28	Connect and Trouble Charges		42.85	2,176	93,246	0	0	2,176	93,246	
29	CIP Incentive		0.00	0	0	0	0	0	0	
30	Rentals		114.17	4,187	478,030	0	0	4,187	478,030	
31	Interchange Revenues		38.21	439,429	16,790,582	32,882	1,256,421	406,547	15,534,161	
32	Sales for Resale		37.10	75,069	2,785,060	3,597	133,449	71,472	2,651,611	
33	Production Associated Revenues		37.10	5,875	217,963	0	0	5,875	217,963	
34	MISO		14.00	9,445	132,230	0	0	9,445	132,230	
35	Point to Point Firm		37.10	56,409	2,092,774	0	0	56,409	2,092,774	
36	Services & Facilities		37.10	8,743	324,365	0	0	8,743	324,365	
37	Ancillary		37.10	23,479	871,071	0	0	23,479	871,071	
38	Distribution Associated Revenues		42.85	159	6,813	0	0	159	6,813	
39	Other		42.85	8,508	364,585	0	0	8,508	364,585	
40	JOA - Rev fr/to PSC		37.10	(4,813)	(178,562)	0	0	(4,813)	(178,562)	
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	42.00	3,746,042	157,329,124	42.04	213,556	8,977,974	42.00	3,532,486	148,351,150
45	Net Annual Amount			431,039			24,597		406,442	
46	Expense / Revenue Factor			0.7441			0.72			
47	Allocated Revenue Amount			320,757			17,695			
48	Net Cash Working Capital			(4,234)			(928)		(3,307)	

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Schedule DM-9

OTHER RATE BASE ITEMS  
 (\$000's)

	Proposed-Avg. Balance	Adjustments	Advocacy Staff	References
1 Materials and Supplies	\$ 7,613	\$ -	\$ 7,613	AEH-1 Schedule 5, page 1 of 1 Updated
2 Fuel Inventory	\$ 5,899	\$ -	\$ 5,899	AEH-1 Schedule 5, page 1 of 1 Updated
3 Non-Plant Assets & Liabilities	\$ (2,100)	\$ -	\$ (2,100)	AEH-1 Schedule 5, page 1 of 1 Updated
4 Prepayments and Others (1)	\$ 6,235	\$ -	\$ 6,235	AEH-1 Schedule 5, page 1 of 1 Updated
5 Total Other Rate Base Items	<u>\$ 17,647</u>		<u>\$ 17,647</u>	

- (1) These Costs Include the following:
- |                       |              |
|-----------------------|--------------|
| Prepayments           | \$1,050,000  |
| Nuclear Outage Amort. | \$5,018,000  |
| Customer Advances     | \$ (18,000)  |
| Customer Deposits     | \$ (213,000) |
| Other Working Cap.    | \$ 398,000   |

OPERATING REVENUES / OPERATING EXPENSES

	Test Year 12/31/13 (\$000's)		Test Year 12/31/13 (\$000's)		Advocacy Staff	References
	Company Present Unadjusted	Adjustments	Company Proposed Adjusted	Adjustments		
<b>1 Operating Revenues:</b>						
2 Retail	\$ 182,724	\$ -	\$ 182,724	\$ (5,647)	\$ 177,077	Schedule DM-11
3 CIP Revenue Adjustment	\$ -	\$ -	\$ -	\$ -	\$ -	
4 Interdepartmental	\$ -	\$ -	\$ -	\$ -	\$ -	
5 Other Operating	\$ 48,616	\$ (3,114)	\$ 45,502	\$ (9,023)	\$ 36,479	Schedule DM-12
6 Gross Earnings Tax	\$ -	\$ -	\$ -	\$ -	\$ -	
7 <b>Total Operating Revenues</b>	<b>\$ 231,340</b>	<b>\$ (3,114)</b>	<b>\$ 228,226</b>	<b>\$ (14,670)</b>	<b>\$ 213,556</b>	
<b>8 Expenses:</b>						
9 <b>Operating Expenses:</b>						
10 Fuel & Purchased Energy	\$ 82,971	\$ -	\$ 82,971	\$ (2,840)	\$ 80,131	Schedule DM-14
11 Power Production	\$ 45,530	\$ 464	\$ 45,994	\$ (10,800)	\$ 35,194	Schedule DM-15
12 Transmission	\$ 14,568	\$ (537)	\$ 14,031	\$ (5,202)	\$ 8,829	Schedule DM-16
13 Distribution	\$ 6,528	\$ 235	\$ 6,763	\$ (227)	\$ 6,536	Schedule DM-17
14 Customer Accounting	\$ 4,358	\$ (72)	\$ 4,286	\$ (47)	\$ 4,242	Schedule DM-18
15 Customer Service & Information	\$ 505	\$ (48)	\$ 457	\$ (131)	\$ 326	Schedule DM-19
16 Sales, Econ. Development & Other	\$ 2	\$ 171	\$ 173	\$ (173)	\$ -	Schedule DM-20
17 Administrative & General	\$ 15,600	\$ (788)	\$ 14,812	\$ (3,634)	\$ 11,178	Schedule DM-21
18 Incentive Compensation	\$ -	\$ -	\$ -	\$ (545)	\$ (545)	Schedule DM-27 footnote 2
19 <b>Total Operating Expenses</b>	<b>\$ 170,062</b>	<b>\$ (575)</b>	<b>\$ 169,487</b>	<b>\$ (23,599)</b>	<b>\$ 145,891</b>	
20 Depreciation	\$ 21,238	\$ 748	\$ 21,986	\$ -	\$ 19,172	Schedule DM-22
21 Amortization	\$ 4	\$ 369	\$ 373	\$ (168)	\$ 205	Schedule DM-23
22 <b>Taxes:</b>						
23 Property	\$ 7,915	\$ 199	\$ 8,114	\$ -	\$ 8,114	Schedule DM-24
24 Gross Earnings	\$ -	\$ -	\$ -	\$ -	\$ -	
25 Deferred Income Tax and ITC	\$ 10,212	\$ 2,464	\$ 12,676	\$ (388)	\$ 12,288	Schedule DM-25
26 Federal & State Income Tax	\$ (2,414)	\$ (3,729)	\$ (6,143)	\$ 7,903	\$ 1,760	Schedule DM-26
27 Payroll & Other	\$ 1,932	\$ (1)	\$ 1,931	\$ (112)	\$ 1,819	Schedule DM-27
28 <b>Total Taxes</b>	<b>\$ 17,645</b>	<b>\$ (1,067)</b>	<b>\$ 16,578</b>	<b>\$ 7,403</b>	<b>\$ 23,981</b>	
29 <b>Total Expenses</b>	<b>\$ 208,949</b>	<b>\$ (525)</b>	<b>\$ 208,424</b>	<b>\$ (19,176)</b>	<b>\$ 189,248</b>	
30 AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	
31 <b>Total Operating Income</b>	<b>\$ 22,391</b>	<b>\$ (2,589)</b>	<b>\$ 19,802</b>	<b>\$ 4,506</b>	<b>\$ 24,308</b>	
32 <b>Rate Base</b>			\$ 375,678		\$ 322,514	
33 <b>Rate of Return</b>			7.90%		7.138%	
34 <b>Operating Income</b>			\$ 29,682		\$ 23,021	

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Schedule DM-11

RETAIL OPERATING REVENUES

	Test Year 12/31/13 \$000's			
	Company Proposed	Adjustment	Advocacy Staff	Reference
Retail Operating Revenues	\$ 182,724	\$ (5,647)	\$ 177,077	Pg S-4, 2010, 2011, 2012 Earnings Reports NDPSC NDPSC-5-071 NDPSC-5-039 Exhibit Notice Schedule 2 page 1 of 1

OTHER OPERATING REVENUES

		Test Year 12/31/13 \$000's			
		Company Proposed	Adjustment	Advocacy Staff	Reference
1	Other Operating Revenues	\$ 48,616	\$ (9,052)	\$ 39,564	E-2, 2010, 2011, 2012 Earnings Reports NDPSC
2	Adjustments:				
3	Asset Margin Sharing	\$ (505)		\$ (505)	NDPSC-1-008 and WP- A-18
4	Non-Asset Margin Sharing	\$ (334)		\$ (334)	WP-A-19
5	Emission Credit Amortization	\$ (87)	\$ 29	\$ (58)	WP-A-29
6	MISO CWIP Revenue and Expense	\$ (2,188)		\$ (2,188)	AEH-1, Sch. 6, p 2 of 3, Updated
7	Total	\$ 45,502	\$ (9,023)	\$ 36,479	

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Scheduled DM-13

OPERATING EXPENSE SUMMARY

	(\$000's)					
	Company Proposed	Adjustments	Advocacy Staff	References		
1 Fuel and Purchased Energy	\$ 82,971	\$ (2,840)	\$ 80,131	Schedule DM-13		
2 Power Production	\$ 45,994	\$ (10,800)	\$ 35,194	Schedule DM-14		
3 Transmission	\$ 14,031	\$ (5,202)	\$ 8,829	Schedule DM-15		
4 Distribution	\$ 6,763	\$ (227)	\$ 6,536	Schedule DM-16		
5 Customer Accounting	\$ 4,286	\$ (44)	\$ 4,242	Schedule DM-17		
6 Customer Service & Information	\$ 457	\$ (131)	\$ 326	Schedule DM-18		
7 Sales, Econ. Development & Other	\$ 173	\$ (173)	\$ -	Schedule DM-19		
8 Administrative & General	\$ 14,812	\$ (3,634)	\$ 11,178	Schedule DM-20		
9 Total Company Proposed	<u>\$ 169,487</u>	<u>\$ (20,211)</u>	<u>\$ 146,436</u>			

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Scheduled DM-14

FUEL AND PURCHASED ENERGY

	(\$000's)			
	Company Proposal	Adjustments	Advocacy Staff	References
1 Beginning Balance-Unadjusted	\$ 82,971	\$ (2,840)	\$ 80,131	Pg E-2, 2010, 2011, 2012 Annual Reports NDPSC

POWER PRODUCTION

	(\$000's)				
	Company Proposed	Adjustments	Advocacy Staff	References	
1 Beginning Balance-Unadjusted	\$ 45,530	\$ (3,421)	\$ 42,109	NDPSC-5-013, Attach C, p. 4 of 13 Pg. e-2, 2010, 2011, 2012 Annual Report to NDPSC	
Allocation Factor of 83.3%	\$ 45,530	\$ (10,453)	\$ 35,077	Table KRP-1	
2 Nuclear Outage Amortization	\$ 121	\$ (30)	\$ 91	WP-A6-4	
3 Nuclear Fees & Budget Update	\$ 493	\$ (240)	\$ 253	WP-A7-3	
4 Nuclear Management Retention Program	\$ 77	\$ (77)	\$ -	WP-A8-4	
5 Sherco 3 Project	\$ (227)	\$ -	\$ (227)	AEH-1, Sch. 6 p 3 of 3	
6 Total Proposed Power Production	<u>\$ 45,994</u>	<u>\$ (10,800)</u>	<u>\$ 35,194</u>		

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Schedule DM-16

TRANSMISSION EXPENSES

	(\$000's)				
	Company Proposed	Adjustments	Advocacy Staff	References	
1 Beginning Balance - Unadjusted	\$ 14,568	\$ (3,484)	\$ 11,084	Pg E-2, 2010, 2011, 2012, Annual Report to NDPSC	
Allocation Factor of 84.5%	\$ 14,568		\$ 9,366	Table KRP-1	
2 MISO CWIP Revenue/Expense Adjustment	\$ (537)		\$ (537)	WP-A30	
3 Total Transmission Expense	<u>\$ 14,031</u>	<u>\$ (5,202)</u>	<u>\$ 8,829</u>		

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Schedule DM-17

DISTRIBUTION EXPENSES

	(\$000's)				
	Company Proposed	Adjustments	Advocacy Staff	References	
1 Beginning Balance-Unadjusted	\$ 6,528	\$ (227)	\$ 6,301	Pg E-2 ND Annual Reports, 2010, 2011, 2012	
2 ND- Line Employees	\$ 235	\$ -	\$ 235	WP -A10	
3 Total Distribution	<u>\$ 6,763</u>	<u>\$ (227)</u>	<u>\$ 6,536</u>		

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Schedule DM-18

CUSTOMER ACCOUNTING

	(\$000's)			
	Company Proposed	Adjustments	Advocacy Staff	References
1 Beginning Balance-Undadjusted	\$ 4,358	\$ (47)	\$ 4,311	Pg E-2 ND Annual Reports 2010, 2011, 2012
2 Bad Debt Expense	\$ (72)	\$ 3	\$ (69)	WP-A09
3 Total Customer Accounting	<u>\$ 4,286</u>	<u>\$ (47)</u>	<u>\$ 4,242</u>	

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Schedule DM-19

CUSTOMER SERVICE AND INFORMATION

	(\$000's)			
	Company Proposed	Adjustments	Advocacy Staff	References
1 Beginning Balance-Undadjusted	\$ 505	\$ (131)	\$ 374	Pg E-2 ND Annual Reports 2010, 2011, 2012
2 Advertising	\$ (48)	\$ -	\$ (48)	AEH-1, Schedule 6, p 2 of 3
3 Total Customer Service & Information	<u>\$ 457</u>	<u>\$ (131)</u>	<u>\$ 326</u>	

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Schedule DM-20

SALES, ECONOMIC AND DEVELOPMENT AND OTHER

	(\$000's)			
	Company Proposed	Adjustments	Advocacy Staff	References
1 Beginning Balance - Unadjusted	\$ 2	\$ (2)	-	AEH-1 Sch 6, page 1 of 3, Updated Pg E-2 2010, 2011, 2012, Annual Report to NDPSC
2 Economic Development	\$ 171	\$ (171)	-	WP-A-14
3 Total Sales, Econ. Development & Other	<u>\$ 173</u>	<u>\$ (173)</u>	<u>-</u>	

ADMINISTRATIVE AND GENERAL EXPENSES

	(\$000's)				
	Company Proposed	Adjustments	Advocacy Staff	References	
1 Beginning Balance-Unadjusted	\$ 15,600	\$ (3,229)	\$ 12,371	Pg E-2 ND Annual Reports 2010, 2011, 2012	
2 Shared Asset Allocation	\$ (196)	\$	\$ (196)	AEH-1, Sch. 6, p 1 of 3, Updated	
3 Advertising	\$ (143)	\$	\$ (143)	AEH-1, Sch. 6, p 2 of 3, Updated	
4 Association Dues	\$ 19	\$ (23)	\$ (4)	WP-A-12	
5 Donations	\$ 157	\$ (157)	\$ -	WP-A-13	
6 Interest on Customer Deposits	\$ 1	\$	\$ 1	AEH-1, Sch. 6, p 2 of 3, Updated	
7 Aviation	\$ (52)	\$	\$ (52)	NDPSC-2-103	
8 Wholesale Billing	\$ (3)	\$	\$ (3)	AEH-1, Sch. 6, p 2 of 3, Updated	
9 Cell Phone Policy	\$ (7)	\$	\$ (7)	AEH-1, Sch. 6, p 2 of 3, Updated	
10 Rate Case Budget Exclusion	\$ (24)	\$	\$ (24)	AEH-1, Sch. 6, p 2 of 3, Updated	
11 Incentive Pay (1)	\$ (530)	\$ (223)	\$ (753)	NDPSC-5-045, Att A., 1-018, Att A, WP-A-27	
12 Pension Update	\$ 246	\$	\$ 246	NDPSC-5-026, Supp.	
13 Active Health Care Update	\$ (250)	\$	\$ (250)	NDPSC-5-026, Supp.	
14 Incentive Compensation Correction	\$ (6)	\$ (2)	\$ (8)	NDPSC-5-026, Supp.	
15 Total Administrative & General	<u>\$ 14,812</u>	<u>\$ (3,634)</u>	<u>\$ 11,178</u>		

(1) Please also see Public Service Commission of Wisconsin Final Decision, (Excerpts) pages 26 and 27,

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 Schedule DM-22

DEPRECIATION

Updated June 6, 2013  
 (\$000's)

	Company Proposed	Adjustments	Advocacy Staff	References
1 Beginning Balance-Unadjusted	\$ 21,238	\$ (277)	\$ 20,961	Sch. DM-4 Line 4 times 2.44%
2 Bemidji CapX2020 Project	\$ 39	\$	\$ 39	Exh AEH-1 Schedule 6, p 1 of 3
3 Brookings CapX2020 Project	\$ 1	\$	\$ 1	Exh. AEH-1. Schedule 6, p 1 of 3
4 Depreciation Study	\$ 1,042	\$ (1,400)	\$ (358)	MJM Supplemental Testimony
5 Remaining Life Study	\$ (254)	\$ 254	\$	- MJM Supplemental Testimony
6 Black Dog Cost of Removal	\$ -	\$	\$	- Exh. AEH-1, Schedule 6, p 2 of 3
7 AFUDC Correction	\$ 5	\$	\$ 5	Exh. AEH-1, Schedule 6, p 2 of 3
8 Monticello License	\$ (56)	\$	\$ (56)	Exh AEH-1, Schedule 6, p. 2 of 3
9 Projects Out of 2013	\$ (7)	\$	\$ (7)	NDPSC-5-026, Suppl, p 1 & 2
10 Sherco 3	\$ (22)	\$	\$ (22)	Exh AEH-1, Schedule 6, p 3 of 3
11 Total Depreciation	<b>\$ 21,986</b>	<b>\$ (1,423)</b>	<b>\$ 20,563</b>	
12 Allocation Factor of 87.20%			\$ 17,931	Table KRP-1

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		AMORTIZATION				
		(\$000's)				
		Company Proposed	Adjustments	Advocacy Staff	References	
1	Beginning Balance-Unadjusted	\$ 4	\$ -	\$ 4	AEH-1 Sch. 6, p 1 of 3 Updated	
2	ND-DSM	\$ 56	\$ (19)	\$ 37	AEH-1 Sch. 6 p 2 of 3, Updated /WP-A20	
3	Rate Case Amortization - current case	\$ 206	\$ (155)	\$ 51	NDPSC-1-015, Attach C, p 1	
4	Prior ND Rate Case	\$ 71	\$ (24)	\$ 47	WP-A-20	
5	Private Fuel Storage	\$ 69	\$ (23)	\$ 46	WP-A-20	
6	Emission Credit Amortization	\$ (33)	\$ 11	\$ (22)	WP-A-20	
7	Total Amortization	\$ 373	\$ (210)	\$ 163		

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Schedule DM-24

PROPERTY TAXES

	(\$000's)				
	Company Proposed	Adjustments	Advocacy Staff	References	
1 Beginning Balance-Unadjusted	\$ 7,915	\$ -	\$ 7,915	NDPSC 5-086, AEH-1 Sch 6, page 1 of 3	
2 Bemidji CapX2020	\$ 25	\$ -	\$ 25	AEH-1 Sch. 6 p 1 of 3 Updated	
Property Tax Update	\$ 174	\$ -	\$ 174	AEH-1 Sch. 6 p 3 of 3 Updated	
3 Total Property Taxes	<u>\$ 8,114</u>	<u>\$ -</u>	<u>\$ 8,114</u>		

DEFERRED INCOME TAXES AND ITC

	(\$000's)					
	Company Proposed		Adjustments		Advocacy Staff	References
1 Beginning Balance-Unadjusted	\$ 10,212	\$	-	\$	10,212	AEH-1 Sch. 6 p 1 of 3, Updated
2 Bemidji CapX2020	\$ 35	\$	-	\$	35	AEH-1 Sch. 6 p 1 of 3, Updated
3 Brookings CapX2020	\$ 42	\$	-	\$	42	AEH-1 Sch. 6 p 1 of 3, Updated
4 Nuclear Fuel Update	\$ 13	\$	-	\$	13	AEH-1 Sch. 6 p 1 of 3, Updated
5 Depreciation Study	\$ (425)	\$	-	\$	(425)	AEH-1 Sch. 6 p 1 of 3, Updated
6 Remaining Life Study	\$ 104	\$	-	\$	104	AEH-1 Sch. 6 p 1 of 3, Updated
7 AFUDC Correction	\$ (8)	\$	-	\$	(8)	AEH-1 Sch. 6 p 1 of 3, Updated
8 AFUDC MISO Correction	\$ (3)	\$	-	\$	(3)	AEH-1 Sch. 6 p 1 of 3, Updated
9 Monticello License	\$ (4)	\$	-	\$	(4)	AEH-1 Sch. 6 p 1 of 3, Updated
10 Projects out of 2013	\$ (34)	\$	-	\$	(34)	AEH-1 Sch. 6 p 1 of 3, Updated
11 Sherco 3	\$ 9	\$	-	\$	9	AEH-1 Sch. 6 p 1 of 3, Updated
12 Black Dog Cost of Removal	\$ -	\$	-	\$	-	AEH-1 Sch. 6 p 1 of 3, Updated
13 NOL Adjustment	\$ 2,735	\$	(358)	\$	2,377	Rate Base (DM-1) times .728%
14 Total Deferred Income Tax and ITC	\$ 12,676	\$	(358)	\$	12,318	

INCOME TAXES - FEDERAL AND STATE

	(\$000's)			
	Company Proposed	Advocacy Staff	Difference	References
<b>Income Before Taxes</b>				
1 Total Operating Revenues	\$ 228,226	\$ 213,556	\$ 14,670	Schedule DM-10
2 Total Operating Expenses	\$ (169,487)	\$ (145,891)	\$ 23,596	Schedule DM-10
3 Book Depreciation and Amortization	\$ (22,359)	\$ (18,094)	\$ 4,265	Schedules DM-22 and 23
4 Taxes (Other than Current Income)	\$ (22,721)	\$ (22,251)	\$ 470	Schedule DM-10
5 Total Before Tax Book Income	\$ 13,659	\$ 27,320	\$ 28,331	
<b>Tax Additions</b>				
6 Book Depreciation	\$ 21,986	\$ 17,931	\$ -	Schedule DM-22
7 Deferred Income Taxes & ITC	\$ 12,676	\$ 12,318	\$ -	Schedule DM-25
8 Nuclear Fuel Burn (ex D&D)	\$ 7,249	\$ 7,249	\$ -	AEH-1, Sch. 8 p 4 of 6, Updated
9 Nuclear Outage Accounting	\$ 4,664	\$ 4,664	\$ -	AEH-1, Sch. 8 p 4 of 6, Updated
10 Avoided Tax Interest	\$ 2,915	\$ 2,915	\$ -	AEH-1, Sch. 8 p 4 of 6, Updated
11 Total Tax Additions	\$ 49,490	\$ 45,077	\$ -	
<b>Tax Deductions</b>				
12 Debt Interest Expense	\$ 8,753	\$ 7,593	\$ (1,160)	Schedule DM-28
13 Tax Depreciation & Removal	\$ 68,192	\$ 68,192	\$ -	
14 Other Tax/Book Timing Differences	\$ 2,223	\$ 2,223	\$ -	
15 Total Tax Deductions	\$ 79,168	\$ 78,008	\$ (1,160)	
16 State Taxable Income	\$ (16,019)	\$ (5,610)	\$ 10,409	
17 State Income Tax Rate	5.15%	5.15%		
18 State Taxes Before Credits	\$ (825)	\$ (289)	\$ 536	AEH-1 Sch 8, p 5 of 6, Updated
19 State Credits	\$ -	\$ -	\$ -	
20 Total State Income Taxes	\$ (825)	\$ (289)	\$ 536	
21 Federal Taxable Income	\$ (15,194)	\$ (5,322)	\$ 9,873	
22 Federal Income Tax Rate	35.00%	35.00%		
23 Federal Tax Before Credits	\$ (5,318)	\$ (1,863)	\$ 3,455	AEH-1 Sch 8, p 5 of 6, Updated
24 Federal Tax Credits	\$ -	\$ -	\$ -	
25 Total Federal Income Taxes	\$ (5,318)	\$ (1,863)	\$ 3,455	
26 Total Federal and State Income Taxes	\$ (6,143)	\$ (2,151)	\$ 3,992	

PAYROLL AND OTHER TAXES

	(\$000's)				
	Company Proposed	Adjustments	Advocacy Staff	References	
1	\$ 1,931	\$ (112)	\$ 1,819		(1)
(1)	Total Company Payroll - \$23,893,000 minus incentive compensation amounts of \$844, \$3,456, \$483,176, \$887,381 equals \$22,518,143 \$22,518,143 times payroll rate of 8.08% (Total proposed payroll of \$1,931,000/total proposed Labor of \$23,893,000) Exhibit NDPSC- Data Request 5-045, Attachment A Total Payroll is shown on Company Exhibit AEH-1, Schedule 8, Updated, Page 6 of 8, Line 9, ND Retail Electric ( Cash Working Capital Schedule)				
(2)	Total Company Incentive (NDPSC-5-045 Attachment A)				
	\$ 1,374,757				
	Less Incentive Compensation removed in Schedule DM-20				
	\$ 753,000				
	Less Incentive Compensation removed in Schedule DM-14				
	\$ 77,000				
	<u>\$ 544,757</u>				
	Balance - Schedule DM-10				

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INTEREST SYNCHRONIZATION

			<u>Reference</u>
1	Recommended Rate Base	\$ 326,528	Schedule DM-1
2	Recommended Cost of Debt	<u>2.33%</u>	Schedule DM-2
3	Recommended Interest Expense	<u>\$ 7,593</u>	