

Direct Testimony and Schedules  
Anne E. Heuer

Before the North Dakota Public Service Commission  
State of North Dakota

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

Docket No. PU-10-\_\_\_\_  
Exhibit\_\_\_\_(AEH-1)

**2012 Step-In Adjustment**

December 20, 2010

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1 **I. INTRODUCTION AND QUALIFICATIONS**

2  
3 Q. PLEASE STATE YOUR NAME AND OCCUPATION.

4 A. My name is Anne E. Heuer. I am the Manager of Revenue Analysis for Xcel  
5 Energy Services Inc. (“XES” or the “Service Company”). My qualifications  
6 and experience are summarized in the resume provided with my testimony as  
7 Exhibit\_\_\_\_(AEH-1), Schedule 1.

8  
9 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

10 A. I am testifying on behalf of Northern States Power Company, a Minnesota  
11 corporation (“Xcel Energy” or the “Company”) operating in North Dakota  
12 regarding the Company’s request for a 2012 step-in adjustment as described by  
13 Company witness Ms. Laura McCarten in her Direct Testimony. I present and  
14 support the Company’s request for a step-in adjustment to recover the full-  
15 year effect of specific rate-base additions in 2011, as well as specific known  
16 and measureable 2012 wind related transmission payments and nuclear outage  
17 amortization costs that are critical to the successful operation of our electric  
18 utility business. First, I will explain the Company’s request for a step-in  
19 adjustment to address a portion of the Company’s 2012 revenue deficiency,  
20 and how the step-in adjustment would help address the challenges facing the  
21 Company as it moves out of the 2011 test year and directly into a year where  
22 another significant deficiency is expected. Second, I will describe the step-in  
23 adjustment the Company is seeking. Third, I will introduce the Company’s  
24 2012 Cost of Service Study (“COSS”) as a tool by which parties can further  
25 evaluate the reasonableness of the step-in adjustment the Company is  
26 requesting. Finally, I respond to a Commission inquiry concerning the  
27 possibility of moving from base rate recovery of Company-owned wind-

1 project costs to recovery via a rider mechanism. Ms. Laura McCarten provides  
2 a discussion of the reasons for the cost increases included in the 2012 Step and  
3 the Commission’s authority to set rates that reflect these cost increases.  
4

5 Q. HOW HAVE YOU ORGANIZED YOUR DIRECT TESTIMONY?

6 A. My testimony is presented in the sections outlined below:

- 7 • Request for Step-in Adjustment
- 8 • Components of Step-in Adjustment
- 9 • 2012 Jurisdictional Cost of Service Study
- 10 • Rider Recovery for Wind-Project Costs
- 11 • Conclusion

## 12 **II. REQUEST FOR STEP-IN ADJUSTMENT**

13  
14  
15 Q. PLEASE EXPLAIN THE COMPANY’S REQUEST.

16 A. As introduced in Ms. McCarten’s Policy testimony, the Company requests  
17 permission to implement a 2012 step-in adjustment in final rates as a means of  
18 providing the Company a reasonable opportunity to earn a rate of return that  
19 is closer to the authorized rate of return approved by the North Dakota Public  
20 Service Commission (“Commission”) in this proceeding. Without the step-in  
21 adjustment, the final rates placed into effect in 2012 (after the end of the 2011  
22 test year) will result in an under-recovery of the Company’s 2012 costs of  
23 providing service to customers in North Dakota. In fact, as the step-in  
24 adjustment request is only for a portion of the Company’s forecasted 2012  
25 revenue deficiency; the Company still expects to earn less than its authorized  
26 return, but the shortfall will be eased by inclusion of the step-in adjustment.  
27 Our specific step-in adjustment request is proposed to include, in 2012 rates,

1 the revenue requirements of four specific items that are known and  
2 measurable. These items are necessary in order to maintain the Company's  
3 ability to provide safe and reliable electric service to its customers in North  
4 Dakota.

5  
6 Q. HOW WOULD THE STEP-IN ADJUSTMENT WORK?

7 A. The step-in adjustment increase proposed for 2012 would consist of a set of  
8 four specific cost components that are contributing to the Company's  
9 forecasted revenue deficiency in 2012. The 2012 revenue requirement  
10 associated with these specific costs would be combined with the cost of  
11 service approved by the Commission for the 2011 test year in determining  
12 rates to be in effect for 2012. If adjustments are made to the 2011 Cost of  
13 Service that have a carry-over effect on the specific items included in the step-  
14 in adjustment (such as cost of capital), the step-in adjustment request would be  
15 adjusted to reflect such carry-over effect.

16  
17 Q. WHEN WOULD THE STEP-IN ADJUSTMENT BECOME EFFECTIVE?

18 A. The Company requests the step-in adjustment be effective January 1, 2012.  
19 We will make a specific proposal regarding how to roll the step-in adjustment  
20 into rates once the revenue requirement is determined in the Commission's  
21 final Order. Company witness Mr. Steven V. Huso generally describes how  
22 the 2012 step-in adjustment would be recovered through final rates in his  
23 Direct Testimony.

24  
25 Q. HOW MUCH IS THE COMPANY REQUESTING AS A STEP-IN ADJUSTMENT IN 2012?

1 A. The Company is requesting a \$4.226 million revenue increase in 2012 above  
2 the 2011 test-year deficiency of \$19.773 million based on the revenue  
3 requirements for the four specific components discussed below.

4  
5 Q. WHAT IS THE PERCENTAGE INCREASE IN BASE RATES THAT THE COMPANY IS  
6 REQUESTING?

7 A. The total combined percent increase in retail revenues for 2011 and 2012  
8 (\$19.773 million + \$4.226 million) is 14.59 percent. A COSS has been  
9 provided for both the 2011 test year and the step-in adjustment request.  
10 Company witness Mr. John M. Felling discusses the Cost of Service Studies in  
11 more detail in his Direct Testimony. See Exhibit\_\_\_\_(JMF-1), Schedule 8a and  
12 8b, respectively.

13  
14 Q. WHAT IS THE COMPANY'S PROJECTED RETURN ON EQUITY WITH THE 2012  
15 STEP-IN ADJUSTMENT?

16 A. The 2012 return on equity with the step-in adjustment is projected to be 10.90  
17 percent, roughly 35 basis points below the 11.25 percent return on equity  
18 requested by the Company in this proceeding. This assumes, for simplicity,  
19 that 100 percent of the proposed \$19.773 million revenue deficiency in 2011 is  
20 recovered along with the Company's request for the \$4.226 million step-in  
21 adjustment in 2012. The Company's projected earned return on equity would  
22 be less than the return authorized by the Commission, but the Company  
23 would earn closer to its authorized return. Absent the step-in adjustment, the  
24 Company projects an earned return of 9.51 percent in the first year final rates  
25 are in effect, as shown in the 2012 COSS, as shown in Exhibit\_\_\_\_(AEH-1),  
26 Schedule 7. The Company proposes that the cost of capital approved for the  
27 2011 deficiency be applied to the 2012 step adjustment.

1 Considering the basis point difference is helpful in understanding the  
2 magnitude of the Company's concern. Without the proposed step-in  
3 adjustment, the Company's projected 2012 return on equity would be roughly  
4 174 basis points below the authorized level in the year in which the final rates  
5 are first placed into effect. Because the step-in adjustment is primarily  
6 associated with capital items, any change to the cost of capital would likewise  
7 change the amount of the step-in adjustment, such that the relative basis point  
8 deficiencies would be fairly similar regardless of one's view on the appropriate  
9 cost of capital. This information underscores the need for a step-in  
10 adjustment as outlined by Ms. McCarten. It also shows that the Company is  
11 not likely to over-earn.

12  
13 **III. COMPONENTS OF STEP-IN ADJUSTMENT**

14  
15 Q. WHAT ARE THE SPECIFIC COMPONENTS OF THE STEP-IN ADJUSTMENT?

16 A. The step increase consists of four projects with three capital components and  
17 two operation and maintenance ("O&M") expense components. The capital  
18 components are: the Company-owned Merricourt Wind project  
19 ("Merricourt"), the Monticello Life Cycle Management and Extended Power  
20 Uprate ("Monticello LCM/EPU") project, and Transmission Plant. The  
21 O&M expense components are Nuclear Outage Amortization expense, which  
22 is driven in large part by outages occurring in 2010 and 2011, and Midwest  
23 ISO Tariff payments to Montana Dakota Utilities ("MDU") for transmission  
24 network upgrades necessary to connect the Merricourt project to the  
25 transmission system. Finally we include an associated impact on Cash  
26 Working Capital, which slightly decreases the total proposed step-in  
27 adjustment. The corresponding revenue requirement for each component is

1 displayed in Table 1 below, and I will describe each component in my  
2 testimony. Furthermore, Schedules 2 through 5 to this testimony provide  
3 calculations of the revenue requirements for each component of the step-in  
4 adjustment.

5  
6 **Table 1**  
7 **Revenue Requirements for Step-In Components**

8

<b>Component</b>	<b>2012 Revenue Requirement</b>
Monticello LCM/EPU	\$1.531M
Transmission Plant	\$0.515M
Merricourt (Including MDU Transmission Payments)	\$1.855M
Nuclear Outage Amortization	\$0.339M
<b>Subtotal</b>	<b>\$4.240M</b>
Change in Cash Working Capital	-\$0.040M
Change in Cost of Capital	\$0.028M
Rounding	-\$0.002M
<b>TOTAL</b>	<b>\$4.226M</b>

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18

19  
20 Q. CAN YOU DESCRIBE THE COMPANY'S CRITERIA FOR SELECTING THESE SPECIFIC  
21 ADJUSTMENTS?

22 A. Yes. First, we focused on capital costs associated with our core operational  
23 portions of the business: nuclear and transmission, which have the most direct  
24 benefit to ratepayers. Second, as Merricourt is scheduled to go into service at  
25 the end of 2011, the Company will incur a full year of costs in 2012. The  
26 project is needed as an essential step in meeting North Dakota's Renewable  
27 Energy Objective and the renewable energy policies established by the other  
28 jurisdictions we serve. Lastly, we attempted to tie the specific adjustment

1 proposal to costs that would already be reviewed in the 2011 test year, thus  
2 eliminating the need for a full initial review of the 2012 cost of service.

3  
4 **A. Step-In Adjustment Capital and Expense Components**

5 Q. PLEASE DESCRIBE THE MONTICELLO LCM/EPU COMPONENT IN MORE  
6 DETAIL.

7 A. As discussed in more detail in Company witness Mr. Dennis L. Koehl's Direct  
8 Testimony, the Monticello LCM/EPU project will increase the power output  
9 at Monticello by 71 megawatts ("MW") and also address necessary  
10 investments needed to keep the plant operating safely and reliably into its  
11 extended license life. The Monticello project received its Certificate of Need  
12 for license extension in 2007 and a Certificate of Need for the Extended  
13 Power Uprate in 2009. This is by far the largest of the projects and a  
14 significant driver of the 2012 step-in adjustment. Our total plant addition for  
15 the LCM/EPU modifications will be roughly \$360 million. Approximately  
16 \$75 million was placed into service prior to 2011 and is not part of the step-in  
17 adjustment. All but a small portion of the remaining \$285 million will be  
18 placed into service by December 2011 (about \$650,000 is scheduled to be in  
19 service in the first few months of 2012).

20  
21 The result is a 2011 test year that reflects only a small portion of the annual  
22 depreciation expense and only slightly more than half of the total rate base.  
23 The 2012 step-in adjustment reflects a full year's worth of depreciation,  
24 property taxes and return on 2012 average rate base related to the project,  
25 thereby allowing the Company an opportunity to recover the investment and a  
26 fair return in 2012 rates. Exhibit\_\_\_\_(AEH-1), Schedule 2 provides a  
27 calculation of the corresponding revenue requirement of \$1.531 million.

1 Q. PLEASE DESCRIBE THE TRANSMISSION PLANT COMPONENT IN MORE DETAIL.

2 A. As described in Company witness Mr. Ian R. Benson's Direct Testimony, new  
3 transmission projects generally fall under three categories: system  
4 performance, which is primarily related to keeping the system operating  
5 reliably; interconnection, which is primarily related to new network  
6 transmission facilities that are necessary to connect a new generator or  
7 substation to the grid; and transmission serving generation. As Mr. Benson  
8 discusses, the Company expects to place approximately \$183.5 million of  
9 transmission investments into service over the course of 2011, with \$139.2  
10 million of transmission capital being placed in to service in 2012, resulting in  
11 further increases to transmission plant-in-service.

12

13 The Company is seeking an adjustment of \$515,000 to account for the full  
14 year's depreciation expense, property taxes and return component on 2011  
15 investments that will be recognized in 2012 when final rates are placed into  
16 effect. Please refer to Exhibit\_\_\_(AEH-1), Schedule 3 for the detailed  
17 revenue requirements calculation.

18

19 Q. PLEASE DESCRIBE THE MERRICOURT WIND PROJECT COMPONENT IN MORE  
20 DETAIL.

21 A. The Merricourt Wind Project is a 150 MW wind energy generation facility  
22 consisting of 100 GE 1.5 MW SLE wind turbines located within a project site  
23 encompassing approximately 9,600 acres in McIntosh and Dickey Counties,  
24 North Dakota. The Commission approved the wind project as a reasonable  
25 and prudent electric resource addition to NSP's system and granted a  
26 Certificate of Public Convenience and Necessity to construct and operate the  
27 150 MW project via an Order issued on August 12, 2009 (Case Nos. PU-08-

1 908 and PU-08-910). enXco Development Corporation is constructing  
2 Merricourt pursuant to an Engineering, Procurement and Contracting  
3 (“EPC”) agreement. Construction on the project is planned to start Spring of  
4 2011 towards a projected in-service date of November 2011. Company  
5 witness Ms. Pamela K. Graika discusses in her Direct Testimony the benefits  
6 of the project to Xcel Energy’s resource mix diversification and how it helps  
7 provide a hedge against fuel price volatility.

8  
9 In addition to our capital investment in the Merricourt project, our 2012 step-  
10 in adjustment for this project includes an annualization of our payment to  
11 MDU for required network upgrades made under the terms of the Midwest  
12 ISO (“MISO”) tariff. Please see Mr. Benson's Direct Testimony for a detailed  
13 description of the upgrade project.

14  
15 The Company is seeking an adjustment of \$1.855 million for Merricourt costs  
16 that will be incurred and recognized in 2012 when final rates are placed into  
17 effect. Of this amount, \$1.639 million is related to our capital investment in  
18 this project (including depreciation, property taxes and return on rate base)  
19 and \$216,000 represents our annualized payment to MDU for transmission  
20 network upgrades. Please refer to Exhibit\_\_\_(AEH-1), Schedule 4 for the  
21 detailed revenue requirements calculation.

22  
23 Q. PLEASE DESCRIBE THE NUCLEAR AMORTIZATION EXPENSE COMPONENT IN  
24 MORE DETAIL.

25 A. The nuclear amortization cost reflects the actual outage costs that have been  
26 (or will be) deferred and subsequently amortized over the useful life of the  
27 outages. As shown in Table 2 below, the amortized outage costs in 2012 are

1 driven in large part by costs that are being incurred by the Company in 2010  
2 and 2011 as well as an outage that will begin shortly after the test year ends, in  
3 February of 2012.

4  
5 **Table 2**  
6 **Nuclear Amortized Outage Costs (NSPM Company Electric)**  
7

Unit/Year	PI U2 2010 Actual	Monti 2011 Budget	PI U1 2011 Budget	PI U2 2012 Budget	PI U1 2012 Budget	Total
Total Outage Cost	\$ 36.3M	\$ 41.6M	\$ 26.7M	\$39.5M	\$41.2M	
Portion included in 2012 Amortization Expense	\$ 3.3M	\$ 20.8M	\$ 15.7M	\$20.1M	\$4.6M	\$64.5M

8  
9 Including amortization expenses, the Company's overall nuclear O&M budget  
10 is projected to increase by 6.1 percent from 2011 to 2012, resulting in an  
11 additional \$17.8 million in costs for 2012. The step-in adjustment for the  
12 nuclear amortization component only seeks to recover the increased costs  
13 directly related to the nuclear plant outages.

14  
15 This adjustment relies on 2012 budget data. The timing of our nuclear outages  
16 are well known, as they are driven by the rate of fuel burn and the need to take  
17 refueling outages to maintain operations of the plant at safe and efficient  
18 levels. Similarly, the cost of an outage is well known, because the scope of an  
19 outage is driven by regulatory requirements or known capital additions. If  
20 anything, our experience is that we underestimate the cost of our outages,  
21 because we do not attempt to budget a contingency for emergent work that  
22 may arise during the course of an outage. Our outage plan is developed many  
23 years in advance, and significant requirements of the outages and their scope  
24 are thus well known in advance. These increases are driven by the total

1 number of outages and the increased scope of work during the outages needed  
2 to address safety and regulatory requirements. The incremental revenue  
3 requirement driven by the increased nuclear outage amortization cost and  
4 associated rate-base component is \$339,000 in 2012, as shown in  
5 Exhibit\_\_\_(AEH-1), Schedule 5. Please refer to Mr. Koehl's Direct  
6 Testimony for details on the nuclear outage costs and scope of work.

7  
8 **B. Calculation of the Plant-Related Step-in Adjustment**  
9 **Revenue Requirements**

10 Q. PLEASE EXPLAIN HOW THE PROPOSED PLANT-RELATED STEP-IN COMPONENTS  
11 WERE CALCULATED.

12 A. The revenue requirements for the Monticello LCM/EPU and Merricourt step-  
13 in adjustments and the transmission plant step-in adjustment were calculated  
14 using two different methods. For the Monticello LCM/EPU and Merricourt  
15 components, the revenue requirements were calculated in a manner similar to  
16 the calculations used for the Company's rate case test year. In other words,  
17 the return on rate base was calculated using the 2012 average of beginning of  
18 year ("BOY") and end of year ("EOY") net utility plant in service multiplied  
19 by the 2011 rate of return. Total depreciation expense was calculated using  
20 the monthly book depreciation schedule for 2012. Tax effects (income,  
21 deferred, and property) were also considered in addition to the AFUDC offset  
22 and avoided tax interest.

23  
24 For the Transmission Plant component, the revenue requirements were  
25 calculated using the 2011 Year End net rate base to establish the return  
26 component, a full year of depreciation based on the 2011 composite  
27 depreciation rate applied to the 2011 Year End plant balance, and the  
28 recognition of property taxes related to the increased property value.

1 The revenue requirements shown in Exhibit\_\_\_\_(AEH-1), Schedules 2 through  
2 5 are calculated using the 2008 capital structure. I used the 2008 capital  
3 structure so that any change in the overall cost of capital would not also cause  
4 a corresponding revenue requirement change for each item included in the  
5 step-in. An adjustment to reconcile the capital structure differences was made  
6 in the 2012 Step Adjustment COSS (Exhibit\_\_\_\_(JMF-1), Schedule 8b), and  
7 shown in Table 1. The 2012 revenue requirement for the change in cost of  
8 capital is \$28,000 and is also shown on the Test Year Income Statement  
9 Adjustment Schedule (Exhibit\_\_\_\_(JMF-1), Schedule 5b, Column 43). This  
10 methodology is consistent with the methodology used to develop the 2011  
11 Cost of Service.

12  
13 Q. WHY WERE THE REVENUE REQUIREMENTS FOR THE CAPITAL PROJECTS  
14 CALCULATED DIFFERENTLY?

15 A. There are two related reasons for the different methodologies. First, the  
16 depreciation timelines for the Monticello LCM/EPU and Merricourt projects  
17 are much shorter than the depreciation timelines for transmission capital  
18 investments. The depreciation lives of the Monticello EPU and Merricourt  
19 projects are 20 years and 25 years respectively. By contrast, the average  
20 depreciation life for transmission projects is approximately 40 years.  
21 Therefore, the depreciation effect on the net plant balance of the Monticello  
22 and Merricourt projects will be much more significant in 2012, and it is  
23 necessary to use an average 2012 net plant-in-service balance to recognize that  
24 effect.

25  
26 Second, the Monticello LCM/EPU and Merricourt projects are large projects  
27 that will begin depreciating in late 2011 with minimal additional investments

1 (for the specific project) after 2011. Because the projects will mostly be placed  
2 in service in late 2011 (December and November, respectively), the 2011 test-  
3 year result captures only a very small portion of this projects' ongoing annual  
4 depreciation expense. The step-in adjustments are necessary to capture this  
5 ongoing annual expense. On the other hand, the Transmission Plant  
6 component represents the total transmission plant-in-service at EOY 2011.  
7 This amount will continue to grow in 2012 and beyond as the Company  
8 maintains its high level of investment in Transmission Plant. Using 2011 year-  
9 end figures results in a lower rate base than using 2012 average transmission  
10 net rate base, and it provides the Commission and Parties with assurance that  
11 customers will only be paying rates in 2012 for transmission investments that  
12 are used and useful for all of 2012.

13  
14 According to our current 2011 and 2012 capital budgets and the resulting 2012  
15 Cost of Service, the 2012 average net rate base for Transmission will be \$56  
16 million, while the comparable 2011 year-end rate base is \$54 million, as shown  
17 in Exhibit\_\_\_(AEH-1), Schedule 6. The step-in adjustment request is for less  
18 than the total revenue requirements associated with the additional rate base  
19 resulting from Transmission plant additions in 2012. This gives assurance that  
20 the approach taken to calculate the 2012 step-in adjustment request will not  
21 result in the Company collecting more than its actual costs of expected 2012  
22 Transmission in the rates developed through the step-in adjustment.

23  
24 Q. IS THERE ANOTHER BENEFIT TO USING THE 2011 END-OF-YEAR PLANT  
25 BALANCE FOR THE TRANSMISSION CALCULATION?

26 A. Yes. By using the 2011 EOY balance, we are dealing with items that are  
27 known at the end of the test year and can be measured for their 2012 effect by

1 examining the 2011 test-year information. The same reasoning applies to the  
2 use of a 2011 composite depreciation rate used to annualize depreciation  
3 expense.

4  
5 Q. PLEASE EXPLAIN THE ASSOCIATED DECREASE IN REVENUE REQUIREMENTS  
6 FOR CASH WORKING CAPITAL.

7 A. The adjustments made for these components impact a variety of expense  
8 items that are considered in the Company's cash working capital  
9 determination. The primary driver related to the capital adjustments pertains  
10 to the property tax changes. In this calculation, these expenses are accrued on  
11 average roughly one year in advance of cash payment to the taxing authorities.  
12 The result of the Company having use of these funds is a rate-base deduction  
13 causing a decrease in 2012 revenue requirements of \$40,000. Please refer to  
14 Mr. Felling's Direct Testimony for a general discussion regarding cash working  
15 capital, to Exhibit\_\_\_(JMF-1), Schedule 8b, page 6 for the detailed cash  
16 working capital calculation and to Exhibit\_\_\_(JMF-1), Schedule 5b, Column  
17 44) for the revenue requirement calculation.

18  
19 **IV. 2012 JURISDICTIONAL COST OF SERVICE STUDY**

20  
21 Q. WHY IS THE COMPANY PROVIDING A 2012 JURISDICTIONAL COST OF SERVICE  
22 STUDY?

23 A. The 2012 COSS is being provided with my testimony for informational  
24 purposes. Its primary purpose is to assure the Commission that our step-in  
25 adjustment is not capturing costs that are increasing without also  
26 acknowledging items that may be decreasing the cost of service. For example,  
27 the 2012 COS deficiency occurs despite an increase in revenues from sales

1 growth forecast for that period. The Company is not requesting that rates be  
2 established based on the overall 2012 COSS; our approach with the step-in  
3 adjustment is to avoid the need for Parties to perform an in-depth analysis of  
4 the 2012 test year COSS. The 2012 COSS data is included to provide  
5 assurance to the Commission and stakeholders that the Company will not earn  
6 above its authorized return in 2012 if granted the proposed step-in adjustment.  
7 Parties will need to determine how relevant this information is to their analysis  
8 of the step-in adjustment, but the Company is providing the 2012 COSS to be  
9 more transparent about our anticipated 2012 costs and thus the  
10 reasonableness of our approach.

11  
12 Q. HOW WAS THE 2012 COMPANY BUDGET DEVELOPED?

13 A. The 2012 Company budget was developed in a very similar fashion as the  
14 2011 budget discussed in Mr. Felling's testimony. The budget is assembled  
15 separately by its various components, including Sales Forecast (customers and  
16 consumption), Retail and Other Revenues, Cost of Production, Operating and  
17 Maintenance ("O&M") Expenses, Capital Invested, Other Rate-Base  
18 Investment and Capital Structure Components. The component budgets are  
19 based on documented assumptions concerning anticipated cost and business  
20 trends and follow corporate budget guidance. The various budgets are  
21 submitted to the Xcel Energy Finance Council for review.

22  
23 In preparing for this rate case, the traditional regulatory adjustments were  
24 made to derive the 2012 COSS from the Company's 2012 budget. Please refer  
25 to Mr. Felling's Direct Testimony for a more complete description of the  
26 budgeting and test year development process.

27

1 Q. DOES THE SECOND YEAR BUDGET (2012) PROVIDE A REASONABLE  
2 REPRESENTATION OF THE COMPANY'S 2012 REVENUE REQUIREMENTS?

3 A. Yes, I believe the 2012 budget provides a reasonable representation of the  
4 Company's revenue requirements when final rates in this case will be placed  
5 into effect. While we acknowledge that the precision of the budgeting process  
6 decreases with each additional out year, the Company requires budget  
7 documentation for both the first and second year budgets during the annual  
8 budgeting process. The budgeting process provides the Company with a well-  
9 documented forecast in 2012 that provides a reasonable basis for calculating  
10 the 2012 revenue requirements.

11

12 Q. WHAT IS THE AMOUNT OF THE 2012 JURISDICTIONAL REVENUE REQUIREMENT  
13 FOR NORTH DAKOTA?

14 A. The 2012 jurisdictional retail revenue requirement for North Dakota electric  
15 utility operations is \$191 million, based on average rate base and projected net  
16 operating income for the 2012 test year, the average capital structure, short-  
17 term debt, long-term debt and 11.25 percent cost of equity, based on the  
18 return on equity ("ROE") recommended for the 2011 test year. The 2012  
19 COSS is attached to my testimony as Exhibit\_\_\_\_(AEH-1), Schedule 7, pages 1  
20 through 6.

21

22 Q. WHAT IS THE AMOUNT OF THE COMPANY'S FORECAST 2012 REVENUE  
23 DEFICIENCY?

24 A. The 2012 COSS shows a 2012 revenue deficiency of \$5.268 million. This  
25 revenue deficiency assumes 100 percent recovery of the \$19.773 million 2011  
26 deficiency supported in Mr. Felling's Direct Testimony.

27

1                   **V. RIDER RECOVERY FOR WIND-PROJECT COSTS**

2  
3 Q. DOES THE COMPANY PROPOSE RECOVERING THE COST OF COMPANY-OWNED  
4 WIND PROJECTS IN BASE RATES?

5 A. Yes. The 2011 test year and 2012 step-in adjustments includes the Grand  
6 Meadow, Nobles and Merricourt Company-owned wind projects as a  
7 component of base rates.

8  
9 Q. THE COMMISSION HAS EXPRESSED INTEREST IN THE COMPANY USING A RIDER  
10 MECHANISM TO RECOVER WIND-PROJECT COSTS FOR 2011 AND BEYOND.  
11 PLEASE DISCUSS THE COMPANY'S RESPONSE.

12 A. Company representatives discussed this matter with Commission staff on  
13 November 22, 2010, and staff noted their preference for recovering Company-  
14 owned wind projects through a rider mechanism. Due to the timing of our  
15 meeting with the Commission staff, it was not possible to incorporate rider  
16 cost recovery into our overall rate recovery proposal. However, the Company  
17 is open to exploring rate recovery alternatives with the Commission during the  
18 course of this proceeding, including using a special rate rider to recover wind  
19 project costs.

20  
21                   **VI. CONCLUSION**

22  
23 Q. PLEASE SUMMARIZE YOUR TESTIMONY?

24 A. The Company's proposal for a 2012 step-in adjustment is necessary to address  
25 a significant Company revenue requirement deficiency in 2012 that would not  
26 be adequately addressed if final rates in this case are based only on the 2011  
27 test-year cost of service. The development of the proposed 2012 step-in

1 adjustment is consistent with cost-based ratemaking that has been the historic  
2 cornerstone of all past and current recovery mechanisms. Finally, the 2012  
3 COSS is an informational reference tool useful in understanding the impact of  
4 the proposed step-in adjustments as compared to the Company's complete  
5 financial picture for 2012.

6

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

8 A. Yes, it does.

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

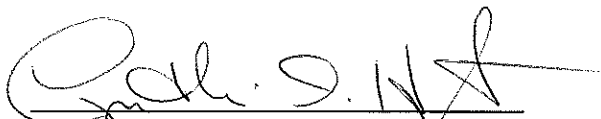
6 In the Matter of the Application of Northern )  
7 States Power Company, a Minnesota corporation )  
8 For Authority to Increase Rates for Electric Service ) Case No. PU-10-\_\_\_\_  
9 in North Dakota )

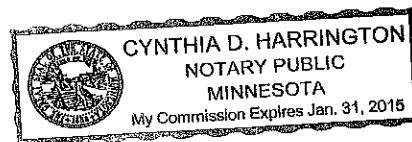
10  
11  
12  
13 **AFFIDAVIT OF**  
14 **Anne E. Heuer**  
15  
16

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

23  
24   
25 Anne E. Heuer  
26

27  
28  
29  
30 Subscribed and sworn to before me, this 5<sup>th</sup> day of December, 2010.  
31

32  
33   
34 Notary Public  
35



Manager  
Revenue Analysis

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

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### **Current Responsibilities**

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

### **Previous Employment (1975 to 2007)**

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

### **Education**

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

### **Prior Testimony**

Minnesota – Overall Revenue Requirements, Rate Base, Income Statement,  
Docket No. E002/GR-10-971, 2010  
Minnesota – Overall Revenue Requirements, Rate Base, Income Statement,  
Docket No. G002/GR-09-1153, 2009  
South Dakota - Overall Revenue Requirements, Rate Base, Income Statement,  
Docket No. EL09-009, 2009  
Minnesota – Overall Revenue Requirements, Rate Base, Income Statement,  
Docket No. E002/GR-08-1065, 2008  
North Dakota - Overall Revenue Requirements, Rate Base, Income Statement,  
Case No. PU 07-776, 2007

2012 Step-in Adjustment  
Revenue Requirement Calculation  
Nuclear Production - Monticello EPU & LCM  
(\$000s)

	2012		2011		Net Change	
	Total Company	ND Jurisdiction	Total Company	ND Jurisdiction	Total Company	ND Jurisdiction
<b>Rate Analysis</b>						
Plant Investment	285,738	13,926	142,707	6,955	143,031	6,971
Depreciation Reserve	(69,101)	(3,368)	(51,377)	(2,504)	(17,724)	(864)
CWIP	-	-	-	-	-	-
Accumulated Deferred Taxes	42,913	2,091	27,784	1,354	15,129	737
	<b>311,926</b>	<b>15,203</b>	<b>166,300</b>	<b>8,105</b>	<b>145,626</b>	<b>7,098</b>
Average Rate Base	311,926	15,203	166,300	8,105	145,626	7,098
Debt Return	10,075	491	5,371	262	4,704	229
Equity Return	17,374	847	9,263	451	8,111	395
Current Income Tax Requirement	9,325	454	(14,776)	(719)	24,101	1,174
Book Depreciation	19,460	948	5,019	245	14,441	704
Annual Deferred Tax	3,529	172	26,729	1,303	(23,200)	(1,131)
ITC Flow Thru	-	-	-	-	-	-
Tax Depreciation & Removal Expense	25,919	1,263	73,197	3,567	(47,278)	(2,304)
AFUDC Expenditure	-	-	-	-	-	-
Avoided Tax Interest	1	-	9,297	453	(9,296)	(453)
Property Taxes	3,254	159	-	-	3,254	159
<b>Total Revenue Requirements</b>	<b>63,018</b>	<b>3,071</b>	<b>31,606</b>	<b>1,542</b>	<b>31,411</b>	<b>1,531</b>

<b>2008 Rate Case Capital Structure</b>	<b>Rate</b>	<b>Ratio</b>	<b>Weighted Cost</b>
Long Term Debt	6.7600%	45.6100%	3.0800%
Short Term Debt	5.7400%	2.6200%	0.1500%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	10.7500%	51.7700%	5.5700%
<b>Required Rate of Return</b>			<b>8.8000%</b>
<b>Tax Rate (ND)</b>	<b>39.2300%</b>		

**Allocators**

Demand Prod ND Jur %	5.8107%
Demand MN Co % (1)	83.8756%
<b>Composite Demand</b>	<b>4.8738%</b>

2012 Step-In Adjustment  
Revenue Requirement Calculation  
Electric Transmission  
(\$000s)

Adjustment Summary

<u>Rate Base</u>	<u>2011 Ending Bal</u>	<u>2011 Average Bal</u>	<u>Net Change</u>
Plant In Service	97,431	93,223	4,208
Depreciation Reserve	30,128	29,259	869
ADIT Basic	13,033	12,356	677
Net Rate Base =	54,270	51,608	2,662
		Debt Return =	86
		Equity Return =	148
		Tax on Equity Return (2) =	96
		<b>Total Rate Base Revenue Requirement =</b>	<b>330</b>
<u>Book Depreciation</u>	<u>2011 Book Depr. Calc. Based on Ending Balance</u>	<u>2011 Book Depreciation</u>	<u>Net Change</u>
2011 Year End Plant =	97,431		
Comp Depr Rate (1) =	2.05%		
Adjusted Deprac =	1,999	1,913	86
		<b>Total Book Depreciation Adjustment =</b>	<b>86</b>
<u>Property Tax</u>	<u>2011 Ending Bal</u>	<u>2011 Beginning Bal</u>	<u>Net Change</u>
Plant Balances =	97,431	89,014	8,417
		Property Tax Rate (3) =	1.18%
		<b>Total Property Tax Adjustment =</b>	<b>99</b>
		<b>Revenue Requirement Total =</b>	<b>515</b>

(1) Composite Book Depr Rate	2.05%
2011 Average Plant in Service	93,223
2011 Book Depreciation	1,913
(2) Composite Tax Rate	39.23%
(3) Composite Property Tax Rate	1.18%

<u>2008 Rate Case Capital Structure</u>	<u>Rate</u>	<u>Ratio</u>	<u>Weighted Cost</u>
Long Term Debt	6.6100%	46.2500%	3.08%
Short Term Debt	4.4100%	1.2800%	0.15%
Common Equity	10.8800%	52.4700%	5.57%
<b>Required Rate of Return</b>			<b>8.80%</b>

**2012 Step-in Adjustment  
Revenue Requirement Calculation  
Other Production - Merricourt  
(\$000s)**

	<b>2012</b>		<b>2011</b>		<b>Net Change</b>	
	Total Company	ND Jurisdiction	Total Company	ND Jurisdiction	Total Company	ND Jurisdiction
<b>Rate Analysis</b>						
Plant Investment	399,965	19,493	199,933	9,744	200,032	9,749
Depreciation Reserve	10,843	528	1,081	53	9,762	476
CWIP	-	-	-	-	-	-
Accumulated Deferred Taxes	51,692	2,519	14,641	714	37,051	1,806
	<b>337,430</b>	<b>16,446</b>	<b>184,211</b>	<b>8,977</b>	<b>153,219</b>	<b>7,467</b>
Average Rate Base	337,430	16,446	184,211	8,977	153,219	7,467
Debt Return	10,899	531	5,950	290	4,949	241
Equity Return	18,795	916	10,261	500	8,534	416
Current Income Tax Requirement	(29,063)	(1,416)	(17,015)	(829)	(12,048)	(588)
Book Depreciation	17,365	846	2,161	105	15,204	741
Annual Deferred Tax	44,413	2,165	29,689	1,447	14,724	718
ITC Flow Thru	-	-	-	-	-	-
Tax Depreciation & Removal Expense	125,594	6,121	78,471	3,824	47,123	2,297
AFUDC Expenditure	-	-	-	-	-	-
Avoided Tax Interest	-	-	10,003	488	(10,003)	(488)
Property Taxes	2,267	110	-	-	2,267	110
MDU Transmission Payments	5,920	289	1,480	72	4,440	216
<b>Total Revenue Requirements</b>	<b>70,595</b>	<b>3,441</b>	<b>32,526</b>	<b>1,585</b>	<b>38,070</b>	<b>1,855</b>

<b>2008 Rate Case Capital Structure</b>	<b>Rate</b>	<b>Ratio</b>	<b>Weighted Cost</b>
Long Term Debt	6.7600%	45.6100%	3.0800%
Short Term Debt	5.7400%	2.6200%	0.1500%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	10.7500%	51.7700%	5.5700%
<b>Required Rate of Return</b>			<b>8.8000%</b>
<b>Tax Rate (ND)</b>	<b>39.2300%</b>		

**Allocators**

Demand Prod ND Jur %	5.8107%
Demand MN Co % (1)	83.8756%
<b>Composite Demand</b>	<b>4.8738%</b>

**2012 Step-in Adjustment  
Revenue Requirement Calculation  
Nuclear Outage Amortization  
(\$000s)**

	<u>ND Jurisdiction 2012</u>	<u>ND Jurisdiction 2011</u>	<u>Difference</u>	<u>Composite IA Factor*</u>	<u>Net Change</u>
Accumulated Deferred Taxes BOY	1,179	1,036	143	83.8527%	120
Accumulated Deferred Taxes EOY	1,675	1,179	496	83.8527%	416
Prepays & Other BOY	2,886	2,537	349	83.8527%	293
Prepays & Other EOY	4,102	2,886	1,216	83.8527%	1,020
Power Production	3,903	3,580	323	83.8527%	271
Deferred Income Tax & ITC	497	143	354	83.8527%	297
Nuclear Outage Accounting Tax Add	3,903	3,580	323	83.8527%	271
Tax Depreciation & Removal Tax Ded	5,119	3,929	1,190	83.8527%	998

<u>Rate Analysis</u>	<u>ND Jurisdiction Before IA Adjustment</u>	<u>ND Jurisdiction After IA Adjustment</u>
Average Prepaid & Other Rate Base	783	656
Average Accumulated Deferred Taxes	320	268
Average Rate Base	463	388
Debt Return	15	13
Equity Return	26	22
Current Income Tax Requirement	(315)	(263)
Outage Amortization Expense	323	271
Annual Deferred Tax	354	297
ITC Flow Thru	0	0
Outage Cost Tax Deduction	1,190	998
AFUDC Expenditure	0	0
Avoided Tax Interest	0	0
Property Taxes	0	0
<b>Total Revenue Requirements</b>	<b>403</b>	<b>339</b>

<u>2008 Rate Case Capital Structure</u>	<u>Rate</u>	<u>Ratio</u>	<u>Weighted Cost</u>
Long Term Debt	6.6100%	46.2500%	3.08%
Short Term Debt	4.4100%	1.2800%	0.15%
Common Equity	10.8800%	52.4700%	5.57%
Required Rate of Return			8.8000%
Tax Rate (ND)	39.2300%		

<u>* Composite IA Allocation Factor</u>	<u>Interchange Agreement</u>	
	<u>Factors</u>	<u>Composite</u>
% Allocated on Demand	48.5607%	83.8756%
% Allocated on Energy	51.4393%	83.8310%
	100.0000%	<b>83.8527%</b>

North Dakota Retail Jurisdiction  
Average Rate Base (Excluding CWIP)  
Transmission Rate Base Comparison

Case No. PU-10-\_\_\_\_  
Exhibit\_\_\_\_(AEH-1), Schedule 6  
Page 1 of 1

<u>Transmission</u>	<u>Average 2011 Test Year</u>	<u>2012 Step</u>	<u>End of Year 2011 Test Year</u>	<u>Average 2012 Bud</u>	<u>Difference</u>
Plant In Service	93,223	4,209	97,431	100,601	3,170
Depreciation Reserve	29,259	869	30,128	30,946	818
Accumulated Deferred Taxes	<u>12,356</u>	<u>677</u>	<u>13,033</u>	<u>13,502</u>	<u>469</u>
Total Rate Base	51,608	2,663	54,270	56,153	1,883

Note: Transmission Rate Base has been adjusted to reflect the impacts of the Interchange Agreement.

**ROE = 9.51%**  
**Deficiency = \$5,268**  
**% Increase = 2.83%**  
**Required ROE = 11.25%**

**Northern States Power Company, a Minnesota corporation**  
**Electric Utility - North Dakota Retail Jurisdiction**  
**Cost of Service Study**  
**2012 2nd Year Budget**

**Summary Reports**

**December 20, 2010**

**Northern States Power Company, a Minnesota corporation**  
**Electric Utility - North Dakota Retail Jurisdiction**  
**Cost of Service Study**  
**2012 2nd Year Budget**

(Dollars in Thousands)

**Rate Base Summary**

	<b><u>Total Company Electric</u></b>			<b><u>ND Retail Electric</u></b>			<b><u>All Other</u></b>		
	<b><u>Beginning Balance</u></b>	<b><u>Ending Balance</u></b>	<b><u>Average Balance</u></b>	<b><u>Beginning Balance</u></b>	<b><u>Ending Balance</u></b>	<b><u>Average Balance</u></b>	<b><u>Beginning Balance</u></b>	<b><u>Ending Balance</u></b>	<b><u>Average Balance</u></b>
1 Plant Investment	14,509,692	15,106,539	14,808,116	800,651	830,614	815,633	13,709,041	14,275,925	13,992,483
2 Depreciation Reserve	<u>(6,780,241)</u>	<u>(7,259,201)</u>	<u>(7,019,721)</u>	<u>(378,758)</u>	<u>(404,900)</u>	<u>(391,829)</u>	<u>(6,401,483)</u>	<u>(6,854,301)</u>	<u>(6,627,892)</u>
3 Net Utility Plant	7,729,451	7,847,338	7,788,395	421,893	425,714	423,804	7,307,558	7,421,624	7,364,591
4 C.W.I.P.	26,741	43,192	34,967	1,706	2,821	2,264	25,035	40,371	32,703
5 Accumulated Deferred Taxes	(1,530,140)	(1,675,571)	(1,602,856)	(85,559)	(94,349)	(89,954)	(1,444,581)	(1,581,222)	(1,512,902)
Other Rate Base:									
6 Cash Working Capital	15,726	15,726	15,726	2,109	2,109	2,109	13,617	13,617	13,617
7 Materials & Supplies	105,544	105,544	105,544	6,170	6,170	6,170	99,374	99,374	99,374
8 Fuel Inventory	90,609	90,609	90,609	5,656	5,656	5,656	84,953	84,953	84,953
9 Non-Plant Assets & Liab	(91,197)	(50,661)	(70,929)	(5,468)	(3,035)	(4,252)	(85,729)	(47,626)	(66,677)
10 Prepaids & Other	69,021	88,311	78,666	4,186	5,398	4,792	64,835	82,913	73,874
<b>11 Total Rate Base</b>	<b>6,415,755</b>	<b>6,464,488</b>	<b>6,440,122</b>	<b>350,693</b>	<b>350,484</b>	<b>350,589</b>	<b>6,065,062</b>	<b>6,114,004</b>	<b>6,089,533</b>

**Northern States Power Company, a Minnesota corporation**  
**Electric Utility - North Dakota Retail Jurisdiction**  
**Cost of Service Study**  
**2012 2nd Year Budget**

(Dollars in Thousands)

**Income Statement Summary**

	<b><u>Total Company Electric</u></b>	<b><u>ND Retail Electric</u></b>	<b><u>All Other</u></b>	
<b><u>Operating Revenues</u></b>				
1	Retail	3,126,154	186,039	2,940,115
2	CIP Adjustment to Program Costs	0	-	0
3	Interdepartmental	610	-	610
4	Other Operating	797,887	46,996	750,891
5	Gross Earnings Tax	0	-	0
6	<b>Total Operating Revenues</b>	<b>3,924,651</b>	<b>233,035</b>	<b>3,691,616</b>
<b><u>Expenses</u></b>				
Operating Expenses:				
7	Fuel & Purchased Energy	1,342,384	83,182	1,259,202
8	Power Production	769,373	45,112	724,261
9	Transmission	230,037	13,329	216,709
10	Distribution	109,792	6,535	103,257
11	Customer Accounting	63,771	4,502	59,269
12	Customer Service & Information	92,301	551	91,750
13	Sales, Econ Dvlp & Other	272	66	206
14	Administrative & General	220,690	14,235	206,454
15	<b>Total Operating Expenses</b>	<b>2,828,620</b>	<b>167,512</b>	<b>2,661,108</b>
16	Depreciation	390,676	20,356	370,320
17	Amortization	24,371	575	23,796
Taxes:				
18	Property	127,340	6,101	121,239
19	Gross Earnings	0	-	0
20	Deferred Income Tax & ITC	142,553	8,673	133,880
21	State & Federal Income (see Page 3)	(31,030)	524	(31,554)
22	Payroll & Other	30,785	1,854	28,931
23	<b>Total Taxes</b>	<b>269,648</b>	<b>17,152</b>	<b>252,496</b>
24	<b>Total Expenses</b>	<b>3,513,315</b>	<b>205,595</b>	<b>3,307,720</b>
25	AFUDC	-	-	-
26	<b>Total Operating Income</b>	<b>411,336</b>	<b>27,440</b>	<b>383,896</b>

**Northern States Power Company, a Minnesota corporation**  
**Electric Utility - North Dakota Retail Jurisdiction**  
**Cost of Service Study**  
**2012 2nd Year Budget**

(Dollars in Thousands)

**Income Tax Summary**

	<b><u>Total Company Electric</u></b>	<b><u>ND Retail Electric</u></b>	<b><u>All Other</u></b>	
<b><u>Income Before Taxes</u></b>				
1	Total Operating Revenues	3,924,651	233,035	3,691,616
2	less: Total Operating Expenses	(2,828,620)	(167,512)	(2,661,108)
3	Book Depreciation & Amortization	(415,047)	(20,931)	(394,116)
4	Taxes (Other Than Current Income)	(300,678)	(16,628)	(284,050)
5	<b>Total Before Tax Book Income</b>	<b>380,306</b>	<b>27,964</b>	<b>352,342</b>
<b><u>Tax Additions</u></b>				
6	Book Depreciation	390,676	20,356	370,320
7	Deferred Income Taxes & ITC	142,553	8,673	133,880
8	Nuclear Fuel Burn (ex D&D)	130,722	7,574	123,148
9	Nuclear Outage Accounting	64,513	3,891	60,622
10	Avoided Tax Interest	30,187	1,698	28,489
11	Open Line	0	0	0
12	Open Line	0	0	0
13	Open Line	0	0	0
14	Open Line	0	0	0
15	Open Line	0	0	0
16	Other Book Additions	0	0	0
17	<b>Total Tax Additions</b>	<b>758,651</b>	<b>42,192</b>	<b>716,459</b>
<b><u>Tax Deductions</u></b>				
18	Debt Interest Expense	182,255	9,922	172,334
19	Tax Depreciation & Removal	905,516	50,901	854,615
20	Manufacture Production Deduction	0	0	0
21	Open	0	0	0
22	Open	0	0	0
23	Open	0	0	0
24	Other Tax/Book Timing Differences	41,590	2,495	39,095
25	Net Preferred Stock Deduction	0	0	0
26	<b>Total Tax Deductions</b>	<b>1,129,361</b>	<b>63,318</b>	<b>1,066,044</b>
27	<b>State Taxable Income</b>	<b>9,595</b>	<b>6,838</b>	<b>2,757</b>
28	State Income Tax Rate	9.03%	6.50%	N/A
29	State Taxes before Credits	866	444	422
30	State Credits	531	0	531
31	<b>Total State Income Taxes</b>	<b>335</b>	<b>444</b>	<b>(109)</b>
32	<b>Federal Taxable Income</b>	<b>9,260</b>	<b>6,394</b>	<b>2,866</b>
33	Federal Income Tax Rate	35.00%	35.00%	35.00%
34	Federal Tax before Credits	3,241	2,238	1,003
35	Federal Tax Credits	34,606	2,158	32,448
36	<b>Total Federal Income Taxes</b>	<b>(31,365)</b>	<b>80</b>	<b>(31,445)</b>
37	<b>Total Federal &amp; State Income Taxes</b>	<b>(31,030)</b>	<b>524</b>	<b>(31,554)</b>

**Northern States Power Company, a Minnesota corporation**  
**Electric Utility - North Dakota Retail Jurisdiction**  
**Cost of Service Study**  
**2012 2nd Year Budget**

**Revenue Requirement & Return Summary**

(Dollars in Thousands)

	<u>Capital Structure</u>	<u>Rate</u>	<u>Ratio</u>	<u>Weighted Cost</u>	<u>Composite Income Tax Rates</u>	
1	Long Term Debt	6.0700%	46.3000%	2.8100%	State of North Dakota Tax rate	6.50%
2	Short Term Debt	2.0600%	1.1400%	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)	32.73%
4	Common Equity	11.2500%	52.5600%	5.9100%	<b>Total North Dakota Composite Tax Rate</b>	<b>39.23%</b>
5	<b>Required Rate of Return</b>			<b>8.7400%</b>	<b>Total Corporate Composite Tax Rate</b>	<b>40.87%</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	411,336	27,440
7	Total Average Rate Base	<u>6,440,122</u>	<u>350,589</u>
8	<b>ROR (Operating Income / Rate Base)</b>	<b>6.39%</b>	<b>7.83%</b>
			<b>6.30%</b>

<b><u>Return on Equity (ROE)</u></b>			
9	Total Operating Income	411,336	27,440
10	Debt Interest (Rate Base * Weighted Debt Cost)	(182,255)	(9,922)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	<u>0</u>	<u>0</u>
12	Earnings Available for Common	229,080	17,518
13	Equity Rate Base ( Rate Base * Equity Ratio)	<u>3,384,928</u>	<u>184,270</u>
14	<b>ROE (Earnings for Common / Equity Rate Base)</b>	<b>6.77%</b>	<b>9.51%</b>
			<b>6.61%</b>

<b><u>Revenue Deficiency</u></b>			
15	Require Operating Income (Rate Base * Required Return)	562,867	30,641
16	Operating Income	<u>411,336</u>	<u>27,440</u>
17	Operating Income Deficiency	151,531	3,202
18	Revenue Conversion Factor ( 1/(1-Composite Tax Rate) )	<u>1.69110</u>	<u>1.64541</u>
19	<b>Revenue Deficiency (Income Deficiency * Conversion Factor)</b>	<b>256,254</b>	<b>5,268</b>
			<b>250,986</b>

<b><u>Total Retail Revenue Requirements</u></b>			
20	Retail Related Revenues	3,126,764	186,039
21	Revenue Deficiency	<u>256,254</u>	<u>5,268</u>
22	<b>Total Retail Revenue Requirements</b>	<b>3,383,018</b>	<b>191,307</b>
			<b>3,191,711</b>

23	<b><u>Percentage Increase (Decrease)</u></b>	<b>8.20%</b>	<b>2.83%</b>
			<b>8.53%</b>

Northern States Power Company, a Minnesota corporation  
 Electric Utility - North Dakota Retail Jurisdiction  
 Cost of Service Study  
 2012 2nd Year Budget

**Rate Base Detail - Cash Working Capital**

(Dollars in Thousands)

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	361,157	7,613,190	22,544	475,228	338,613	7,137,962	
2 Gas for Generation	38.45	167,107	6,425,264	10,431	401,072	156,676	6,024,192	
3 Oil	22.51	1,283	28,880	80	1,801	1,203	27,080	
4 Nuclear & EOL	0.00	130,722	0	8,160	0	122,562	0	
5 Nuclear Disposal	76.00	<u>13,050</u>	<u>991,800</u>	<u>756</u>	<u>57,456</u>	<u>12,294</u>	<u>934,344</u>	
6		673,319	15,059,134	41,971	935,556	631,348	14,123,578	
<b>Purchased Power</b>								
7 Purchases	28.12	876,729	24,653,619	53,111	1,493,481	823,618	23,160,138	
8 Interchange	38.21	<u>127,715</u>	<u>4,879,990</u>	<u>7,488</u>	<u>286,116</u>	<u>120,227</u>	<u>4,593,874</u>	
		1,004,444	29,533,610	60,599	1,779,598	943,845	27,754,012	
<b>Labor &amp; Related Costs</b>								
9 Regular Payroll	12.31	376,540	4,635,207	22,629	278,563	353,911	4,356,644	
10 Incentive Compensation	255.05	22,679	5,784,279	1,419	361,916	21,260	5,422,363	
11 Pension & Benefits	19.20	<u>92,631</u>	<u>1,778,515</u>	<u>5,639</u>	<u>108,269</u>	<u>86,992</u>	<u>1,670,246</u>	
12 Subtotal Labor & Related		491,850	12,198,002	29,687	748,748	462,163	11,449,254	
13								
14 All Other Operating Expenses	35.01	659,007	23,071,844	35,255	1,234,271	623,752	21,837,573	
15 Property Tax	356.72	127,340	45,424,725	6,101	2,176,349	121,239	43,248,376	
16 Employer's Payroll Taxes	26.56	30,785	817,650	1,854	49,242	28,931	768,407	
17 Gross Earnings Tax	41.48	0	0	0	0	0	0	
18 Federal Income Tax	37.75	(31,365)	(1,184,025)	80	3,014	(31,445)	(1,187,038)	
19 State Income Tax	37.75	335	12,649	444	16,780	(109)	(4,130)	
20 State Sales Tax Customer Billings	35.73	141,992	5,073,374	0	0	141,992	5,073,374	
21 Total Expenses	<u>41.97</u>	3,097,707	130,006,962	175,991	6,943,557	2,921,716	123,063,405	
22 Net Annual Expense Amount			<u>356,183</u>		<u>19,023</u>		<u>337,160</u>	
<b>Revenues</b>								
23 Computer Billing	100.00%	45.45	3,126,154	142,092,140	186,039	8,455,975	2,940,115	133,636,165
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	0
26 Interdepartmental	0.00	610	0	0	0	610	0	0
27 Late Payment	0.00	5,615	0	361	0	5,254	0	0
28 Connect and Trouble Charges	42.85	2,275	97,488	245	10,499	2,030	86,990	0
29 CIP Incentive	0.00	0	0	0	0	0	0	0
30 Rentals	114.17	4,032	460,333	255	29,113	3,777	431,220	0
31 Interchange Revenues	38.21	472,754	18,063,930	28,335	1,082,680	444,419	16,981,250	0
32 Sales for Resale	37.10	168,294	6,243,709	10,391	385,493	157,903	5,858,217	0
33 Production Associated Revenues	37.10	6,460	239,666	403	14,951	6,057	224,715	0
34 MISO	14.00	14,658	205,219	849	11,885	13,810	193,333	0
35 Point to Point Firm	37.10	61,421	2,278,719	3,558	132,002	57,863	2,146,717	0
36 Services & Facilities	37.10	8,817	327,111	505	18,736	8,312	308,375	0
37 Ancillary	37.10	60,233	2,234,644	3,490	129,479	56,743	2,105,165	0
38 Distribution Associated Revenues	42.85	1,872	80,219	0	0	1,872	80,219	0
39 Other	42.85	(3,648)	(156,342)	(1,090)	(46,700)	(2,559)	(109,642)	0
40 JOA - Rev fr/to PSC	37.10	(4,896)	(181,642)	(306)	(11,353)	(4,590)	(170,289)	0
41 (blank)	0.00	0	0	0	0	0	0	0
42 (blank)	0.00	0	0	0	0	0	0	0
43 (blank)	0.00	0	0	0	0	0	0	0
44 Total Revenues	<u>43.82</u>	3,924,651	171,985,195	233,035	10,212,760	3,691,616	161,772,435	
45 Net Annual Amount			<u>471,192</u>		<u>27,980</u>		<u>443,212</u>	
46 Expense / Revenue Factor			0.789294986		0.755213995			
47 Allocated Revenue Amount			<u>371,910</u>		<u>21,131</u>			
48 Net Cash Working Capital			<u>15,726</u>		<u>2,108</u>		<u>13,619</u>	