

Rebuttal Testimony and Schedules
Anne E. Heuer

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in North Dakota

Case No. PU-12-813
Exhibit___(AEH-2)

Revenue Requirements

August 12, 2013

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1 I. INTRODUCTION

2
3 Q. PLEASE STATE YOUR NAME AND OCCUPATION.

4 A. My name is Anne E. Heuer. I am Manager of Revenue Analysis for Xcel
5 Energy Services Inc.

6
7 Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS PROCEEDING?

8 A. Yes. I filed Direct Testimony on behalf of Northern States Power Company –
9 Minnesota (NSPM or Company) supporting the Company’s financial data and
10 request for a general and interim rate increase, specifically:

- 11 • the overall revenue requirement of \$199.624 million and revenue
12 deficiency of \$16.900 million, determined by the cost of service for the
13 2013 budget test year; and
- 14 • the interim increase of \$14.704 million as discussed in our Petition for
15 Interim Rates.

16
17 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

18 A. My Rebuttal Testimony and supporting schedules address a number of issues
19 raised by the Commission Advocacy Staff consultants. Specifically, I respond
20 to the financial adjustments suggested by Mr. Dante Mugrace, and the
21 jurisdictional allocator suggested by Dr. Karl R.Pavlovic. I also update our
22 financial statements to reflect those adjustments recommended or accepted by
23 the Company. This includes the Company’s request for a lower return on
24 equity (10.25 percent), as proposed by Ms. Ann E. Bulkley. My Rebuttal
25 Testimony supports a North Dakota jurisdictional electric utility operation
26 overall retail revenue requirement of \$197.608 million and revenue deficiency
27 of \$14.884 million.

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

3 A. Yes, they were.
4

5 **II. SUMMARY AND ORGANIZATION**
6

7 Q. PLEASE PROVIDE A SUMMARY OF YOUR REBUTTAL TESTIMONY

8 A. My Rebuttal Testimony will primarily focus on the Direct Testimony of Mr.
9 Mugrace and Dr. Pavlovic (collectively the Consultants) with respect to the
10 overall revenue requirement, the test-year revenue deficiency, and
11 jurisdictional cost of service. I present an issue-by-issue analysis, discussion,
12 and supporting schedules that produce an overall revenue requirement and
13 revenue deficiency for the 2013 North Dakota jurisdiction electric utility.
14

15 The overall summary of revenue requirements is presented in
16 Exhibit___(AEH-2), Schedule 2. Comparisons between the detailed rate base
17 and operating income in our initial December 18, 2012 Notice of Change in
18 Rates and the Company's proposed Rebuttal request are included in
19 Exhibit___(AEH-2), Schedule 3, Comparison of Detailed Rate Base
20 Components; and Exhibit___(AEH-2), Schedule 4, Comparison Statement of
21 Operating Income.
22

23 Each of the Company's proposed Rebuttal adjustments is included in
24 Exhibit___(AEH-2), Schedule 5a, and Exhibit___(AEH-2), Schedule 5b,
25 which bridges our original Application to our Rebuttal request and shows the
26 resulting impact on rate base and operating income respectively.
27

1 The 2013 Rebuttal test year Cost of Service Study is included as
2 Exhibit___(AEH-2), Schedule 6.

3
4 Q. HOW HAVE YOU ORGANIZED YOUR REBUTTAL TESTIMONY?

5 A. I will first discuss the three recurring adjustments proposed by the Consultants
6 and explain why those adjustments are not . Those three adjustments are:

- 7 1) The use of a three-year historical average to determine selective
8 revenues and expenses.
- 9 2) The use of a historical average 1 coincident peak (1 CP) jurisdictional
10 demand allocator instead of the Company's test year 12 coincident peak
11 (12 CP) jurisdictional demand allocator to allocate production and
12 transmission costs. Company witness Mr. Scott Brockett explains why
13 the Company's 12 CP demand allocator is more appropriate than the 1
14 CP demand allocator developed by Dr. Pavlovic. I explain how the 1
15 CP demand allocator has been incorrectly developed and applied by the
16 Consultants.
- 17 3) The calculation of the revenue requirement for one-time expenses that
18 will be amortized over a three-year period.

19
20 I will also discuss these problems in my responses to the individual
21 adjustments proposed by Mr. Mugrace, which are organized as follows:

22
23 III. Recurring Adjustments

24 A. Three-Year Historical Averaging

25 B. Demand Allocator

26 C. Amortizations

27 IV. Rate Base Components

- 1 A. Plant In Service
- 2 B. Depreciation Reserve
- 3 C. Construction Work in Progress
- 4 D. Accumulated Deferred Income Taxes
- 5 V. Income Statement
- 6 A. Revenues
- 7 1. Retail Sales Forecast
- 8 2. Other Operating Revenues
- 9 3. Asset Based Margin Sharing
- 10 B. Operating and Maintenance Expenses
- 11 1. Fuel and Purchased Energy.
- 12 2. Power Production
- 13 3. Nuclear Outage Amortization
- 14 4. Nuclear O&M budget
- 15 5. Nuclear Employee Retention Program
- 16 6. Incentive Compensation
- 17 7. Transmission
- 18 8. Distribution
- 19 9. Customer Accounting
- 20 10. Rate Case Expense
- 21 11. Bad Debt
- 22 12. Customer Service
- 23 13. Administrative and General
- 24 14. Chamber of Commerce and Charitable Contributions
- 25 15. Economic Development
- 26 16. Payroll Taxes
- 27 17. Federal and State Income Taxes

- 1 18. Cash Working Capital
- 2 19. Net Operating Loss
- 3 20. Interest Synchronization

- 4 VI. Resolved Issues
- 5 A. Corrections and Updates
- 6 B. Wind2Battery

- 7 VII. Compliance and Reporting
- 8 A. Corporate Aviation
- 9 B. Cell Phone Expense
- 10 C. Pension Update

- 11 VIII. Interim Rates
- 12 IX. Conclusion

13
14
15

III. RECURRING ADJUSTMENTS

A. Three-Year Historical Averaging

17 Q. PLEASE DESCRIBE THE CONSULTANTS' USE OF A THREE-YEAR HISTORICAL
18 AVERAGE FOR SELECTED REVENUES AND EXPENSES.

19 A. The Consultants have determined some (but not all) revenues, some (but not
20 all) expenses, and their proposed jurisdictional allocator (but not all
21 jurisdictional allocators) using a three-year historical average.¹ The three years
22 are 2010, 2011 and 2012. Other revenues, expenses, and allocators are
23 determined using the Company's proposed 2013 budget test year.

24

25 Q. WHAT IS THE STATED JUSTIFICATION FOR USING A THREE-YEAR AVERAGE?

¹ Mugrace Direct at, for example, pages 25, 27, 34, 36, 43, 45, 48, 51, and 56. Also Pavlovic Direct, page 9.

1 A. Mr. Mugrace uses a recurring justification that these costs and revenues are
2 “evident, historical in nature and documented in NDPSC Earnings Reports.”
3 He further states that these costs are determined annually and the use of a
4 three-year average provides a smoothing of the costs and revenues.²
5

6 Q. WHAT IS WRONG WITH THIS PROPOSAL?

7 A. There are six problems with this methodology:

- 8 1) A three-year average is inconsistent with the statute that requires
9 matching 12 consecutive months’ of expenses and 12 consecutive
10 months’ of revenues in constructing a test year.
- 11 2) The proposed historical costs, revenues, and demand allocators do not
12 reflect the costs, revenues, and demands during the period rates will be
13 in effect.
- 14 3) The historical average expenses are less than the expense levels in
15 currently approved rates. In addition, Dr. Pavlovic’s three-year average
16 demand allocator does not reflect the higher relative demand in North
17 Dakota during 2013.
- 18 4) The Consultants have not identified reasons to suggest that the
19 Company’s selected 2013 test year expenses or demand loads are not
20 representative going forward.
- 21 5) Using a three-year average for some revenues, expenses, and allocators
22 is inconsistent with the use of a projected test year for the remaining
23 revenues, expenses, and allocators. In addition to being inconsistent,
24 this creates discrepancies in amounts that are typically associated.
- 25 6) Mr. Mugrace’s method of applying a three-year average double counts
26 several regulatory adjustments.

² See e.g., Mugrace Direct at 46 discussing Distribution expenses.

1 I address some of these points now and others during the discussion of
2 individual adjustments.

3
4 Q. WHAT TEST YEAR DID THE COMPANY SELECT FOR DETERMINING THE
5 REVENUE REQUIREMENT?

6 A. We selected a projected test year of calendar year 2013.

7
8 Q. DID MR. MUGRACE ACCEPT THE USE OF A PROJECTED CALENDAR YEAR 2013
9 TEST YEAR?

10 A. Yes. At page 7 of his Direct Testimony, he acknowledges that “the use of a
11 projected test year is consistent with the North Dakota Century Code
12 (N.D.C.C.) § 49-5-04, subd.1.” However, he uses a three-year historical
13 average for some costs, revenues, and allocators using 2010, 2011, and 2012
14 data.

15
16 Q. DOES N.D.C.C. ALLOW FOR USING A THREE-YEAR HISTORICAL AVERAGE IN A
17 TEST YEAR?

18 A. No. That statute provides in part:

19 A public utility, at its option, may use any one of the following
20 twelve-month periods as its test year for rate filings with the
21 commission:

22 a. A historical test year, which may be either the latest twelve-
23 month period for which actual data is available at the time of
24 filing new schedules or the latest calendar or fiscal year for
25 which actual data is available at the time of filing new
26 schedules.

27 b. A current test year, which is any consecutive twelve-month
28 period ending not later than twelve months after the date new
29 schedules are filed. A public utility selecting a current test
30 year also shall file data for the twelve-month period
31 immediately preceding the current test year selected and that
32 period is the “historical period” for the public utility.

1 c. A future test year, which is any consecutive twelve-month
2 period ending no later than twenty-four months after the date
3 new schedules are filed. A public utility selecting a future test
4 year must file data for the twelve consecutive months
5 immediately preceding the future test year and that period is
6 the “current period” for the public utility. (Emphasis added.)
7

8 Three relevant conclusions are apparent from a review of the above statute.
9 First, the Company has the right to select the test year. The Company has
10 selected a future 2013 test year. Second, even if Consultants could propose
11 using a historical test year, it could not be based on a three-year average. A
12 historical test year must be based on a consecutive twelve-month period that is
13 no earlier than the latest period for which actual data is available (that would
14 be 2012). Third, the projected test year must also be a “consecutive twelve-
15 month period.” Mr. Mugrace’s proposal to selectively use a three-year
16 historical average for some revenues, expenses, and allocators is inconsistent
17 with the requirement that a test year use a consecutive twelve-month period.
18

19 Q. WHY IS A PROJECTED TEST YEAR APPROPRIATE?

20 A. The purpose of a test period is to establish the level of revenues and expenses
21 “representative of those that will be experienced during the time the rates are
22 likely to remain in effect.”³ The Commission has expressly found forecasted
23 test years to be an appropriate method of matching rates to the period during
24 which the rates will be in effect:

25 Because the Commission sets rates for the future, it is appropriate to
26 examine a period during which those rates will be in effect. The
27 utilization of a forecast test year adjusted for known and measurable

³ NARUC Electric Utility Cost Allocation Manual, January 1992 at 24.

1 changes permits an accurate basis for setting rates for the future and
2 contributes to rate stability.⁴
3

4 Q. IS THE THREE-YEAR AVERAGE OF EXPENSES AND REVENUES SELECTIVELY
5 CHOSEN BY MR. MUGRACE REPRESENTATIVE OF THE COST OF SERVICE
6 DURING THE PERIOD RATES WILL BE IN EFFECT?

7 A. No. First, in total, his three-year average is \$3.123 million lower than the 2011
8 costs approved to set rates in PU-10-657. Thus, he uses costs that are lower
9 than the cost used to set current rates as shown in Table 1. Further, Mr.
10 Mugrace did not even include the forecasted 2013 costs in his average.
11

12 **Table 1: Three-Year Average Costs Compared to 2011 Settled Costs (\$000's)**

Category	2010 Actual	2011 Actual	2012 Actual	3-Year Average	2011 TY as Settled
Power Production	\$40,558	\$43,220	\$42,550	\$42,109	\$43,062
Transmission	9,725	11,219	12,309	11,084	11,387
Distribution	5,779	6,737	6,387	6,301	6,275
Customer Accounting	4,394	4,411	4,128	4,311	4,385
Customer Service & Information	262	489	370	374	548
Sales, Econ Devel & Other	0	0	0	0	2
Administrative & General	12,374	11,770	12,969	12,371	14,014
Total	\$73,092	\$77,846	\$78,713	\$76,550	\$79,673

13
14
15 Q. WHAT WAS THE AUTHORIZED RETURN IN 2011, AND HOW DID THAT COMPARE
16 TO THE ACTUAL EARNED RETURN IN 2011 AND 2012?

17 A. The authorized return on equity in PU-10-657 was 10.40 percent. The actual
18 return on equity received in 2011 was 9.20 percent, and in 2012 it was 8.69

⁴ E.g. *In re Otter Tail Power Co.*, North Dakota Public Service Commission Case No. 10,334, Order (April 19, 1983); and *Re. Montana Dakota Utilities Company*, Case No. 10,280, 46 P.U.R. 193 (April 12, 1982).

1 percent. If rates are set in this proceeding using an average cost that is lower
2 than our actual costs in 2011, our earnings will be further eroded.

3
4 **B. Demand Allocator**

5 Q. PLEASE DESCRIBE DR. PAVLOVIC'S PROPOSED REPLACEMENT DEMAND
6 ALLOCATOR.

7 A. Dr. Pavlovic proposes replacing the 12 CP demand allocator with a 1 CP
8 demand allocator for production and transmission. Dr. Pavlovic also uses a
9 historical three-year average demand allocator, stating that he does so to
10 reflect Mr. Mugrace's use of a three-year historical average for certain revenues
11 and expenses.⁵

12
13 Q. WHAT ARE THE PROBLEMS WITH THIS PROPOSAL?

14 A. The principal reply to Dr. Pavlovic's proposal is provided by Company
15 witness Mr. Scott Brockett. I note that the 12 CP demand allocation method
16 has been used for decades in North Dakota and the Commission has twice
17 rejected 1 CP proposals by intervenors in previous cases.⁶ I address five
18 additional problems with the creation and application of the proposed
19 replacement demand allocator.

20
21
22
23

⁵ See Dr. Pavlovic Direct at 9.

⁶ Northern States Power Company, Case No. PU-400-91-112, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 8 – 11 (October 31, 1991); affirming use of 12 CP and rejecting 1 CP demand allocator in Northern States Power Company, Case No. PU-400-87-6, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER (June 23, 1992).

1 First, Dr. Pavlovic uses the average of *actual* demand from 2010, 2011, and
2 2012. Some of that demand is weather affected. In contrast, the Company
3 uses forecasted 2013 demand and assumes *normal* weather. Normal weather is
4 the standard for rate setting. The Company's forecasted demand also takes
5 into consideration known changes in demand during the test year, such as the
6 loss of two of the Company's largest customers in the system (the Ford Plant
7 and Verso Paper). The loss of those two customers reduces sales in the
8 Minnesota Large Commercial and Industrial class in 2012 by 4.5 percent and
9 by another 1.7 percent in 2013. We have also lost all but one wholesale
10 customer in Minnesota. As a result, the use of 2010-2012 average demand
11 significantly understates the relative 2013 demand in North Dakota compared
12 to Minnesota. Mr. Brockett, in Schedule 2 attached to his Rebuttal Testimony
13 calculates the 2013 1 CP demand allocator at 5.50 percent. That is 8 percent
14 higher than Dr. Pavlovic's three-year historical average 1 CP demand
15 allocator.⁷

16
17 Second, Dr. Pavlovic's recommendation to change to a three-year historical
18 average 1 CP demand allocator is inconsistent with the energy allocator used
19 to allocate variable energy-related costs included in the test year. The demand
20 allocator is developed based on the sales forecast. The vintage of data used to
21 develop the demand allocator (primarily used to allocate fixed production and
22 transmission costs) should be consistent with the development of the energy
23 allocator primarily used to allocate variable production costs.

24

⁷ $5.5000\% \div 5.0864\% = 1.08$

1 Third, Mr. Mugrace applies the allocator before the Company's adjustments to
2 the budgeted expense are made. The base expenses are allocated to North
3 Dakota using a smaller percentage, while the adjustments are allocated to
4 North Dakota using the larger original percentage. This inconsistency results
5 in disproportionately larger adjustments relative to base expenses and, in
6 essence, over-adjusts the Company's base data. See, for example, Mugrace
7 Direct Schedules DM-4, DM-5, DM-7, DM-15, DM-16.

8
9 Fourth, Mr. Mugrace applies the proposed allocator selectively. See, for
10 example, Mr. Mugrace's proposal to use the Company's 12 CP demand
11 allocator (6.023 percent) to calculate an adjustment to the Nuclear Refueling
12 Outage Amortization rather than the Consultants' 1 CP allocator. (Mugrace
13 Direct at 39).

14
15 Fifth, Mr. Mugrace applies the proposed allocator to selected components of
16 the Cost of Service. For example, the 1 CP demand allocator is applied to
17 Plant In Service, Accumulated Depreciation, Construction Work In Progress,
18 Production expense and Transmission expense. However, the 1 CP demand
19 allocator is not applied to Other Rate Base, Depreciation expense, Property
20 Taxes, Deferred Income Taxes, or Investment Tax Credits.

21
22 Q. PLEASE SUMMARIZE YOUR RESPONSE TO THE CONSULTANTS' RECOMMENDED
23 USE OF A 1 CP DEMAND ALLOCATOR?

24 A. I do not believe adoption of the consultants' recommended adjustments to the
25 2013 test year to reflect a 1 CP demand allocator is appropriate. The use of a
26 historical three-year average 1 CP demand to develop the demand allocator
27 does not result in a representative level of fixed production and transmission

1 costs required to serve North Dakota customers during 2013. Further, the
2 three-year historical average 1 CP demand allocator (used to allocate fixed
3 production costs) is not consistent with the 2013 test year energy allocator
4 used to allocate variable production costs. In addition, the 1 CP demand
5 allocator is generally applied only to base data (not to adjustments) and, as
6 addressed above, is applied selectively and inconsistently. In summary, the
7 consultants' adjustments do not result in test year costs that appropriately and
8 reasonably reflect the cost of providing fixed production and transmission
9 service to North Dakota customers during the period rates are expected to be
10 in effect.

11
12 **C. Amortizations**

13 Q. WHY HAS THE COMPANY PROPOSED A THREE-YEAR AMORTIZATION OF ONE-
14 TIME EXPENSES AND REVENUES?

15 A. As I explained in my Direct Testimony at page 76, we proposed the
16 amortization of one-time expenses and revenues over a three-year period to
17 match the period we expect rates to remain in effect as a result of this rate
18 case. If we recovered the full cost in one year, we would over-recover our cost
19 if rates remain in effect for longer than one year. Conversely, if we recognized
20 the full amount of one-time revenues in one year, our rates would be
21 inadequate to recover our cost of service. We proposed a three-year
22 amortization period because we anticipate filing a rate case within three years.
23 In this manner, we recover one-third of the expense in 2013 through final
24 2013 rates (interim rates are subject to refund and, therefore, 2013 will reflect
25 the final rate level approved by the Commission), one-third in the first year
26 (2014) final rates are in effect and the final third in the second year (2015) final
27 rates are in effect.

1 Q. WHAT ADJUSTMENT HAS MR. MUGRACE MADE WITH RESPECT TO EACH
2 AMORTIZED EXPENSE?

3 A. Mr. Mugrace notes that we will recover one-third of the expense during the
4 first year (through interim rates) and asserts that the expense should therefore
5 be reduced by the amount recovered in the first year (by one-third) and that
6 the remaining two thirds should be amortized over three years. He makes a
7 similar proposal with respect to Emissions Credits, reducing the credit to
8 ratepayers by one-third.

9

10 Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

11 A. No. Under his proposal, we would be denied recovery of one-third of our
12 one-time costs, and ratepayers would be denied one-third of the Emissions
13 Credits. As an example, assume that we have a one-time expense of \$300.
14 Under our mechanism the revenue requirement is set at \$100 ($\$300 / 3$). We
15 will recover \$100 through final 2013 rates, \$100 in year one (2014) of final
16 rates and \$100 in year two (2015) of final rates. Under Mr. Mugrace's
17 proposal, the revenue requirement would be ($\$300$ less $\$100 = \$200 / 3 =$
18 $\$66.67$). We would recover \$66.67 in final 2013 rates⁸, then recover \$66.67 in
19 year one (2014) of final rates, and recover \$66.67 in year two (2015) of final
20 rates for a total of \$200. Mr. Mugrace's proposal denies us recovery of one-
21 third of our expense. Similarly, his proposal also denies ratepayers one-third
22 of the Emissions Credit.

23

⁸ We would initially recover \$100 through interim rates, but then return \$33.33 through the interim rate refund, which would result in the final 2013 authorized amount of \$66.67.

1 Q. HAS MR. MUGRACE PROVIDED ANY REASON WHY THE COMPANY SHOULD BE
2 DENIED ONE-THIRD OF ITS ONE-TIME EXPENSES OR RATEPAYERS ONE-THIRD
3 OF THE EMISSIONS CREDIT?

4 A. No.

5

6

IV. RATE BASE COMPONENTS

7

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

10 A. In summary, our proposed net utility plant investment (Net Plant in Service)
11 in the 2013 test year is the average of the beginning of year and end of year
12 adjusted Plant in Service less Accumulated Reserve for Depreciation balances.
13 This is, in effect, equal to 100 percent of the beginning balance plus 50 percent
14 of the activity that occurs during the test year.

15

16 My Direct Testimony, pages 38-40, provides additional detail. The calculation
17 initially begins with the Company's actual Net Plant in Service balances
18 recorded on the Company's books and records of as of March 31, 2012. The
19 budget projections for April through December 2012 were then applied to the
20 March 31, 2012 balances to arrive at the beginning test-year Net Plant In
21 Service balances. The ending Net Plant In Service balances were determined
22 by applying the 2013 capital budget plant additions, retirements, depreciation,
23 salvage, and removal costs projected to occur during the test year to the
24 beginning test-year balances. Finally, the Net Plant in Service included in the
25 test year Cost of Service Study rate base is the simple average of the beginning
26 of the test year and end of year test year balances.

27

1 **A. Plant In Service**

2 Q. WHAT HISTORICAL BASIS DID MR. MUGRACE USE TO DEVELOP THE PROJECTED
3 PLANT IN SERVICE BALANCES FOR THE TEST YEAR?

4 A. In summary, Mr. Mugrace took average Plant In Service balances for 2012
5 (which only incorporates 50 percent of 2012 activity) plus 100 percent of 2013
6 activity, adjusted, to develop his recommendation for the projected Plant In
7 Service balances for the test year. I outline below the steps Mr. Mugrace took
8 to develop his recommended 2013 Test Year Average Plant in Service balance.

9
10 The Company's annual earnings reports filed with the NDPSC incorporate the
11 same principles, processes, and past Commission precedent that we used as a
12 basis for our 2013 Test Year. Therefore, the rate base balances included in
13 our 2012 Earnings Report (including Plant in Service) reflect an average of the
14 beginning of year and end of year balances.

15
16 In developing the test year Plant In Service balance, Mr. Mugrace first used the
17 2012 Earnings Report as the source for his recommendation (\$780,660,000).
18 However, because his source was the 2012 Earnings Report, this amount is
19 the average of the beginning of year and end of year Plant In Service balances
20 for 2012, not the ending balance at December 31, 2012.

21
22 Second, Mr. Mugrace took the 2013 Test Year total Company electric utility
23 Production, Transmission, Distribution, General and Common capital
24 additions (\$1,533,295,000) and multiplied them by the three-year historical
25 average 1 CP demand allocator (5.1121 percent) used to allocate Production
26 and Transmission assets to jurisdiction. The results are Mr. Mugrace's

1 recommended North Dakota jurisdictional capital additions for 2013
2 (\$78,383,000).

3
4 Third, Mr. Mugrace added his recommended 2013 capital additions
5 (\$78,383,000) to his recommended Plant in Service beginning balance
6 (\$780,660,000) and multiplies the result by 87.10 percent (Dr. Pavlovic's
7 recommended Plant in Service allocation factor, a composite allocator
8 intended to adjust the Company's recommended 2013 test year Plant In
9 Service for the 1 CP demand allocator). The result is his recommended test
10 year Plant In Service beginning balance (\$748,227,000).

11
12 Finally, Mr. Mugrace applies the Company's recommended Forecasted
13 Updates and Rate Case Adjustments for the Brookings and Bemidji
14 CAPX2020 transmission projects, Nuclear Fuel Updates, and other Company
15 reductions set forth in supplemental data requests. Mr. Mugrace does not
16 apply either Dr. Pavlovic's Plant in Service factor or the 1 CP demand factor
17 to these adjustments.

18
19 The end result of the above steps is Mr. Mugrace's Recommended Plant in
20 Service Balance 2013 of \$748,783,000.

21
22 Q. DOES THE COMPANY AGREE WITH MR. MUGRACE'S DETERMINATION FOR THE
23 PLANT IN SERVICE BALANCE?

24 A. No, the Company disagrees for several reasons.

- 25 • The amount reported in the 2012 Earnings Report filed with the
26 NDPSC represents the Average Balances for 2012, not the end of 2012
27 balance needed to determine Plant in Service for the beginning balance

1 for the 2013 test year. The 2012 Earnings Report average Plant In
2 Service balance was calculated based on an ending balance as of
3 December 31, 2012 of \$793,076,000, and is the appropriate amount; not
4 the \$748,227,000 used by Mr. Mugrace..

- 5 • Not all capital additions are allocated to the North Dakota Jurisdiction
6 using the demand allocator. Distribution, for instance, is direct
7 assigned to jurisdiction based on the asset's physical location. The
8 capital additions allocated to North Dakota recommended by Mr.
9 Mugrace do not represent an average test year balance using this
10 methodology.
- 11 • Dr. Pavlovic's Plant In Service allocation factor is a composite factor
12 calculated based on 2013 test year data. Applying this 2013 factor to
13 average 2012 Plant In Service balances is inconsistent due to the
14 changes in Plant in Service in 2013. In addition, the Company's
15 processes calculate North Dakota jurisdictional amounts based on asset
16 function, not composite allocators applied to all assets. For example,
17 most Production and all Transmission Plant In Service is allocated to
18 jurisdiction based on the demand allocator while Distribution Plant in
19 Service is direct assigned to the jurisdiction in which the asset is located.
- 20 • Mr. Mugrace applied allocation factors twice to the 2013 plant
21 additions: first when he applied the 1 CP demand factor to total
22 Company plant additions to calculate the North Dakota jurisdictional
23 capital additions and second when he applied the Plant In Service factor
24 to develop his recommended beginning Plant In Service balance.
- 25 • Mr. Mugrace did not apply the same allocation methodology to the
26 adjustments as he did to the base data.

- 1 • The Company does not agree with the proposal to replace the 12 CP
2 demand allocator with a 1 CP demand allocator.

3
4 Q. WHY IS THE DIFFERENCE BETWEEN BALANCE CALCULATION METHODS
5 IMPORTANT?

6 A. First, the difference is important because the average 2012 balance does not
7 fully recognize, and thereby undervalues, investments the Company made
8 during 2012. Second, applying allocation factors twice to 2013 activity also
9 undervalues investments made during the test year. Finally, the inconsistency
10 in applying allocations to base data versus adjustments results in
11 disproportionately large adjustments (reductions).

12
13 **B. Depreciation Reserve**

14 Q. WHAT IS MR. MUGRACE'S RECOMMENDATION FOR THE ACCUMULATED
15 DEPRECIATION RESERVE BALANCE TO INCLUDE IN THE TEST YEAR?

16 A. Mr. Mugrace took the Company's proposed 2013 test year average
17 Accumulated Depreciation Reserve balance of \$418,885,000 and applied Dr.
18 Pavlovic's 87.2 percent Reserve allocation factor to calculate his recommended
19 Accumulated Depreciation Reserve beginning balance of \$365,268,000. He
20 then accepted and included the Company's proposed adjustments (to which
21 the Reserve allocation factor was not applied) to derive a total proposed
22 Accumulated Depreciation Reserve balance of \$365,689,000.

23
24 Q. DO YOU AGREE WITH MR. MUGRACE'S PROPOSED DEPRECIATION RESERVE?

25 A. No. I do not agree with the proposal to replace the 12 CP demand allocator
26 with a 1 CP demand allocator for the reasons described in Section III above. I
27 note that Mr. Mugrace's development of Accumulated Reserve for

1 Depreciation starts with the Company's unadjusted 2013 test year average
2 balance. This is inconsistent with Mr. Mugrace recommended approached in
3 developing the average test year Plant In Service balance, which is incorrectly
4 based on a 2012 average balance (described in detail previously in my Rebuttal
5 Testimony).

6
7 **C. Construction Work in Progress**

8 Q. HAS CWIP BEEN INCLUDED IN THE TEST YEAR RATE BASE?

9 A. Yes. However, the only CWIP that is included in rate base are costs related to
10 projects of a short-duration that do not accrue Allowance for Funds Used
11 During Construction (AFUDC). Thus, there is no AFUDC offset added to
12 operating income. The rate base amount reflects a simple average of projected
13 short-term CWIP beginning and ending test-year balances. This is consistent
14 with the method employed in past North Dakota electric rate cases and
15 matches the use of an average rate base.

16
17 Q. HOW WERE THE TEST YEAR BEGINNING AND ENDING CWIP BALANCES
18 DETERMINED?

19 A. The Company's proposed beginning test-year balance for CWIP was the
20 March 31, 2012 actual balance. Construction expenditures, and transfers to
21 Plant in Service during the remaining months of 2012 were netted against the
22 March 31, 2012 CWIP balance to derive a beginning test-year balance. The
23 beginning test-year CWIP balance was adjusted to reflect projected
24 construction expenditures, and transfers to Plant In Service during the 2013
25 test year to obtain the ending test-year CWIP balance. These projections were
26 developed from the Company's 2013 capital budget.

27

1 Q. WHAT IS MR. MUGRACE'S RECOMMENDATION OF SHORT-TERM CWIP
2 INCLUDED IN THE TEST YEAR RATE BASE?

3 A. Mr. Mugrace recommends applying Dr. Pavlovic's CWIP allocation factor
4 (84.80 percent) to the Company's test year short-term CWIP balance of
5 \$2,037,000, reducing the test year CWIP balance to \$1,727,000.
6

7 Q. DOES THE COMPANY AGREE WITH MR. MUGRACE'S DETERMINATION OF
8 SHORT-TERM CWIP?

9 A. No, for two basic reasons. First, the Company does not agree with the
10 proposal to replace the 12 CP demand allocator with a 1 CP demand allocator
11 for the reasons described in Section III above. Second, the Company's
12 processes calculate North Dakota jurisdictional amounts based on asset
13 function, not composite allocation factors applied to all assets as is the case
14 with Dr. Pavlovic's CWIP allocation factor. For example, most Production
15 and all Transmission CWIP are allocated to jurisdiction based on the demand
16 allocator while Distribution CWIP is direct assigned to the jurisdiction in
17 which the asset is being constructed.
18

19 **D. Accumulated Deferred Income Taxes**

20 Q. WHAT IS MR. MUGRACE'S RECOMMENDATION OF ADIT INCLUDED IN THE
21 TEST YEAR RATE BASE?

22 A. Mr. Mugrace took the ratio of the Accumulated Deferred Income Taxes
23 (ADIT) balance to the Company's Plant in Service for the unadjusted test year
24 ($\$90,835/\$868,630 = 10.45$ percent). He performed the same calculation for
25 the proposed test year updated in June 2013 ($\$92,805/\$869,185 = 10.67$
26 percent). He then averaged these ratios to come up with 10.56 percent which

1 he applied to his recommended Plant in Service balance of \$748,783,000 to
2 derive his recommended ADIT balance of \$79,072,000.

3
4 Q. DOES THE COMPANY AGREE WITH MR. MUGRACE'S DETERMINATION OF
5 ADIT?

6 A. No, for several reasons. First, Mr. Mugrace bases his test year ADIT
7 recommendation on his recommended Plant In Service, which incorporates
8 the proposal to replace the 12 CP demand allocator with a 1 CP demand
9 allocator and includes other inconsistencies as discussed earlier in my Rebuttal
10 Testimony. Second, the Company's proposed test year ADIT balances
11 includes all adjustments, allocates the functional ADIT detail consistent with
12 all other rate base items and does an averaging of beginning of year and end of
13 year balances. Finally, Mr. Mugrace's ratio methodology does not ensure a
14 continuing record between the beginning and ending ADIT balances in
15 conjunction with the annual deferred tax expense. For all of these reasons,
16 Mr. Mugrace's recommendation should not be adopted.

17
18 Q. PLEASE SUMMARIZE WHY THE COMPANY'S METHOD OF DEVELOPING THE
19 NORTH DAKOTA JURISDICTIONAL TEST YEAR RATE BASE SHOULD BE USED AS
20 THE BASIS FOR SETTING RATES FOR CUSTOMERS IN NORTH DAKOTA.

21 A. The 2013 test year rate base I propose in my Rebuttal Testimony should be
22 adopted by the Commission and used to set North Dakota electric customer
23 rates for the following reasons:

- 24 • The Company's 2013 test year rate base (Net Plant In Service, CWIP
25 and ADIT) is based on our 2013 budget, adjusted for known changes
26 and supported by other Company witnesses and reflects the cost of

1 providing service to North Dakota electric customers during the period
2 we expect rates to be in place.

- 3 • The Company's methods used to allocate and direct assign costs to the
4 North Dakota electric jurisdiction are consistently applied to all rate
5 base items (Net Plant In Service, CWIP, and ADIT).
- 6 • The Company uses detailed actual and forecast plant records to
7 jurisdictionalize its NSPM electric utility assets, based on sound cost
8 causative allocation principles or direct assignments. For example, all
9 rate base items related to Distribution assets located in North Dakota
10 should be and are assigned to North Dakota customers. Similarly, all
11 rate base items related to Distribution assets located in Minnesota
12 should be and are assigned to Minnesota customers and are excluded
13 from the test year. The same holds true for the consistent allocation of
14 all components of rate base related to fixed Production and
15 Transmission assets, all of which should be allocated to the North
16 Dakota electric jurisdiction based on the demand allocator.

17
18 For these reasons, the Company's method of developing the test year North
19 Dakota jurisdictional rate base should be used as the basis for setting rates for
20 electric customers in North Dakota and the Commission should adopt our
21 proposed test year rate base.

22 23 **V. INCOME STATEMENT**

24 25 **A. Revenues**

26 **1. Retail Sales Forecast**

1 Q. WHAT ADJUSTMENT DID MR. MUGRACE MAKE WITH RESPECT TO FORECASTED
2 SALES?

3 A. Mr. Mugrace started with the Company's projected 2013 sales of 2,270,721
4 MWh and increased those sales by 1.54 percent (934,969 MWh). The 1.54
5 percent is the percentage by which actual first quarter 2013 sales increased
6 over actual first quarter 2012 sales. To determine the revenue value of his
7 adjustment, he calculated a three-year average revenue per kWh.

8

9 Q. DO YOU AGREE WITH MR. MUGRACE'S PROPOSAL?

10 A. No, for several reasons. First, the Company's 2013 proposed test year sales
11 are 2.9 percent higher than the 2012 actual sales.⁹ Having already increased
12 2012 sales by 1.5 percent in developing the Company's 2013 sales forecast, it
13 would not appropriate to add an additional 1.54 percent increase. If the 1.54
14 increase were to be used, it would first be necessary to back out the increase
15 the Company made in developing its 2013 sales forecast. Otherwise, using Mr.
16 Mugrace's method, the sales increase in 2013 would be double counted and in
17 fact, would yield a 4.5 percent increase over 2012 actual sales levels.¹⁰

18

19 Second, the Company completed a sales forecast update in July 2013. The
20 updated forecast reflects a 2.0 percent increase over 2012 actual sales.
21 Increasing 2012 actual sales by 2 percent would result in a forecast of
22 2,251,140 MWh, which is also less than the forecasted 2,270,721 MWh used in

⁹ 2,271 MWh (2013 Company) / 2,207 MWh (2012 Actual) = 1.029. Sales volumes as shown on Mugrace Direct, page 24. Also note that Heuer Direct, page 15, Table 4, shows our projected 2013 sales level is 1.5 percent higher than the forecasted 2012 level at the time of filing. Therefore, actual 2012 sales were less than forecasted 2012 sales.

¹⁰ 2,306 MWh (2013 Mugrace) / 2,207 MWh (2012 Actual) = 1.045. Mr. Mugrace recommended sales volumes as shown on Mugrace Direct, page 25.

1 the test year. In every case, the Company's initial forecast is higher (resulting
2 in a lower revenue deficiency).

3
4 Third, the revenue impact of changing test year sales should be determined by
5 applying present rates, not by applying a three-year average as done by Mr.
6 Mugrace. The three-year average of historic retail rates is particularly
7 problematic for computing revenues because new rates were set in 2012 due
8 to the completion of a rate case. The historic average of retail rates is not
9 representative of rates going forward, as evidenced by current rates and this
10 rate proceeding.

11
12 Q. WHAT DOES THE COMPANY PROPOSE WITH RESPECT TO A 2013 SALES
13 FORECAST?

14 A. Either a correction to Mr. Mugrace's sales adjustment or the Company's
15 updated sales forecast would result in lower forecasted present revenues and
16 an increase in the revenue deficiency for the test year. However, we are willing
17 to leave unchanged our proposed sales forecast for the test year. I
18 recommend that no adjustment to retail revenues be made from the level filed
19 in our direct case.

20
21 **2. Other Operating Revenues**

22 Q. WHAT ARE OTHER OPERATING REVENUES AND WHAT ADJUSTMENT IS MR.
23 MUGRACE PROPOSING?

24 A. Other Operating Revenues are revenues from sources other than retail rates
25 and provide a credit to the revenue requirement. The Company credited
26 \$45.502 million of Other Operating Revenue to the North Dakota jurisdiction

1 in our test year.¹¹ Mr. Mugrace used a three-year average and determined that
2 Other Operating Revenues using that methodology should be lower by
3 approximately \$9 million or \$36.479 million. Mr. Mugrace provides no reason,
4 other than his historical average approach for setting this credit at a level lower
5 than forecasted. Note that adopting Mr. Mugrace's proposal increases the
6 revenue requirement by \$9 million.

7
8 Q. DOES THE COMPANY AGREE WITH THIS PROPOSAL?

9 A. No. I previously provided our general objection to using a three-year
10 historical average for selective expense and revenue adjustments. In addition,
11 using Mr. Mugrace's proposed three-year historical average ignores the 2013
12 changes in Other Operating Revenues occurring under the FERC regulated
13 Interchange Agreement tariff between the Company and NSP-Wisconsin
14 (NSPW). More specifically, it ignores anticipated increases in revenues from
15 NSPW due to projected increases in Company production and transmission
16 costs included the proposed 2013 test year. Thus, Mr. Mugrace's method does
17 not apply the principle of matching costs and revenues to the period the rates
18 will be in effect.

19
20 **3. Asset Based Margin Sharing**

21 Q. WHAT IS THE ISSUE WITH RESPECT TO ASSET BASED MARGINS?

22 A. The Company proposes to continue sharing asset based margins with
23 customers, with 85 percent of those margins being paid to customers and the
24 Company retaining 15 percent. Mr. Mugrace observes that there is no sharing
25 mechanism in Minnesota or South Dakota and proposes sharing 100 percent
26 of the asset based margins with customers.

¹¹ Anne Heuer Direct Schedule 11, page 2 of 2; and Mr. Mugrace Direct Schedule DM-12.

1 Q. WHY HAS THE COMMISSION ALLOWED THE COMPANY TO RETAIN 15 PERCENT
2 OF ASSET-BASED MARGINS IN PRIOR CASES?

3 A. In Case PU-07-776, the Commission approved a Settlement that included the
4 85/15 sharing mechanism in part because: “by sharing the gains on asset-
5 based sales, the Parties recognize that the Company is incented to maximize
6 the benefit from these sales.” At the time of its approval, the Commission
7 was aware that Minnesota did not share asset based margins. The fairness and
8 benefits of a sharing mechanism remains the same today. Therefore, we
9 respectfully request continued approval of the 85/15 sharing mechanism.
10 This would allow the Company to retain approximately \$56,000 in forecasted
11 asset based margins. Approval or disapproval has no affect on the revenue
12 deficiency because asset based margins flow to customers though the fuel
13 clause rider (FCR).

14

15 **B. Operating and Maintenance (O&M) Expenses**

16 **1. Fuel and Purchased Energy**

17 Q. WHAT ADJUSTMENT DID MR. MUGRACE MAKE WITH RESPECT TO THE FUEL
18 AND PURCHASED ENERGY COSTS?

19 A. Mr. Mugrace used a three-year historical average to determine the test year
20 level of Fuel and Purchased Energy expense. Using that method, he decreased
21 Fuel and Purchased Energy expense.

22

23 Q. IS THIS ADJUSTMENT APPROPRIATE?

24 A. No. First, as I have explained a three-year historical average is not an
25 appropriate methodology for determining test year expenses. Second, it is
26 particularly inappropriate for Fuel and Purchased Energy expenses. As I
27 explained in my Direct Testimony at 23, these costs are recovered through the

1 FCR and, therefore, it is important to setting reasonable base rates that Fuel
2 and Purchased Energy revenues and expenses match and are offset in the base
3 rate revenue deficiency. In addition, an adjustment to these costs (which are
4 separately recovered through the FCR) along with a matching adjustment for
5 Fuel and Purchased Energy revenues, is unnecessary for establishing the
6 revenue requirement for base rates.

8 2. Power Production

9 Q. WHAT ADJUSTMENT IS MR. MUGRACE PROPOSING WITH RESPECT TO POWER
10 PRODUCTION EXPENSE?

11 A. Mr. Mugrace uses a three-year historical average to determine the Power
12 Production expense. He also uses Dr. Pavlovic's lower 1 CP allocator to
13 further decrease the expense.

14
15 Q. DOES THE COMPANY AGREE WITH THESE RECOMMENDATIONS?

16 A. No. For the reasons explained in the Direct Testimony of Mr. Stephen Foss
17 and Rebuttal Testimony of Mr. Timothy O'Conner, the Company's proposed
18 test year Power Production expense represents the cost of providing Power
19 Production service to customers in North Dakota. As I explained previously
20 in my Rebuttal Testimony, a three-year historical average is not an appropriate
21 methodology for determining test year expenses, as demonstrated by the fact
22 that Mr. Mugrace's proposed Power Production expense is lower than test
23 year costs for 2011 and lower than 2012 actual costs. Additionally, Power
24 Production costs are both weather sensitive and demand sensitive. The
25 expenses in 2010, 2011 and 2012 may therefore have been weather affected.
26 In comparison, our projected power production expense reflects projected

1 demand, and weather normalized sales. Mr. Mugrace provides no evidence
2 that the forecasted 2013 expense is not reasonable.

3
4 In addition, as I explained previously in my Rebuttal Testimony, the Company
5 also disagrees with using a 1 CP demand allocator and the manner in which
6 that 1 CP allocator has been applied. As with other individual costs, Mr.
7 Mugrace applies the 1 CP demand allocator to Power Production expense, but
8 does not apply it to all adjustments on a consistent basis. This inconsistent
9 application of Dr. Pavlovic's recommended three-year average 1 CP demand
10 allocator results in lower Power Production expense than would have resulted
11 had he applied the 1 CP demand allocator consistently to all Power
12 Production expense.

13
14 **3. Nuclear Outage Amortization**

15 Q. DID MR. MUGRACE RECOMMEND A DIFFERENT NUCLEAR OUTAGE
16 AMORTIZATION ADJUSTMENT?

17 A. Yes. Mr. Mugrace recommended a reduction to the test year nuclear outage
18 amortization adjustment of \$30,000 based upon his review and analysis of the
19 adjustment work papers (WP-A6) filed in this proceeding.

20
21 Q. DOES THE COMPANY AGREE WITH MR. MUGRACE'S RECOMMEND
22 ADJUSTMENT TO THE COMPANY'S NUCLEAR OUTAGE AMORTIZATION?

23 A. No. The Company's adjustment was based upon the projected level of
24 amortization associated with the 2013 test year for this proceeding. Mr.
25 Mugrace based his recommended adjustment on what he interpreted as a
26 decrease in total nuclear amortization for fiscal year 2014. However, the 2014
27 level Mr. Mugrace bases his adjustment upon is not a decrease but is actually

1 the incremental increase in the 2014 amortization over the 2013 projected
2 level. The Company provided work paper used by Mr. Mugrace as the basis
3 for his adjustment (WP-A6-4) identifies the annual amortization amounts for
4 2012, 2013, and 2014. The work paper was supplied to show the forecasted
5 annual amortization (2012, 2013, and 2014) over the original budgeted levels
6 based upon the Prairie Island Unit 1 outage costs incurred in late 2012, after
7 the budgets had been finalized. The work paper identified the *incremental*
8 *increase* for each year above the budgeted level for the corresponding year. Mr.
9 Mugrace mis-interpreted the forecast incremental increase over the original
10 2014 budget as the *total annual* amortization level. However, the 2014
11 amortization level is actually greater than the 2013 level in both the base
12 budget and Company's direct adjusted levels. If Mr. Mugrace's intent is to
13 permit the Company to recover the 2014 nuclear outage amortization level, his
14 calculation should add the 2013 and 2014 incremental increases together and
15 then apply the North Dakota jurisdiction allocation factor. The Company is
16 only seeking recovery of the lower 2013 nuclear outage amortization in this
17 proceeding.

18 19 **4. Nuclear O&M Budget**

20 Q. WHAT IS THE ISSUE WITH RESPECT TO THE NUCLEAR O&M BUDGET?

21 A. Mr. Mugrace proposes removing the O&M budget for Monticello. He makes
22 this proposal because "...the Monticello uprate will not be in service ..." ¹²
23 The purpose of the Monticello extended power uprate (EPU) project is to
24 increase the capacity of Monticello.

25
26 Q. DOES THIS MEAN THE PLANT WILL BE OFFLINE UNTIL 2014?

¹² Mugrace Direct, page 39

1 A. No. Mr. Mugrace cites the Company's response to data request NDPSC-5-
2 026, which says:

3 The case as filed reflected 2013 NRC licensing costs associated with
4 the Monticello LCM/EPU addition scheduled to go into service in
5 August and November of 2013. The investment associated with
6 obtaining the 2013 NRC license is not in service until the unit has
7 completed its power ascension testing such that the unit is reliable to
8 operate at a higher capacity level. We estimate the in-service date for
9 the license will be early 2014.
10

11 The Company's direct case anticipated the Monticello plant coming back
12 online in May 2013. The plant did resume operations in July 2013. The plant
13 will operate at its previous rated capacity until the NRC license is issued for
14 additional capacity.
15

16 Q. ARE THE MONTICELLO O&M COSTS IDENTIFIED BY MR. MUGRACE
17 ASSOCIATED WITH THE EPU LICENSE?

18 A. No. The Monticello plant provides an important portion of the Company's
19 electric generation. The O&M budget is associated with the operation of
20 Monticello during 2013. The fact that Monticello will operate at its current
21 licensed capacity is not a basis for denying the O&M costs related to operating
22 the plant during 2013. Further, the EPU license costs are capital costs, not
23 O&M costs. Therefore, Mr. Mugrace's proposed \$240,000 adjustment should
24 not be approved.
25

26 5. Nuclear Employee Retention Program

27 Q. WHAT DOES MR. MUGRACE PROPOSE WITH RESPECT TO THE EXPENSES FOR
28 THE NUCLEAR EMPLOYEE RETENTION PROGRAM?

1 A. He recommends that the program should not be funded because, among other
2 reasons, the Wisconsin Commission does not support incentive payments. He
3 also questions whether the program is needed.

4

5 Q. WHAT IS THE COMPANY'S RESPONSE?

6 A. Mr. O'Connor shows in his testimony that the retention agreements are
7 needed, showing positive results for our customers, and should be funded.
8 Therefore, the Company does not agree with Mr. Mugrace's adjustment.

9

10 **6. Incentive Compensation**

11 Q. WHAT ADJUSTMENT DOES MR. MUGRACE MAKE CONCERNING INCENTIVE
12 COMPENSATION?

13 A. Mr. Mugrace asserts the Company has not provided adequate support for its
14 incentive compensation programs and recommends disallowing all incentive
15 compensation.

16

17 Q. WHAT IS THE COMPANY'S RESPONSE TO THIS PROPOSAL?

18 A. Company witness Ms. Sharon L. Koenig explains that our Annual Incentive
19 Compensation (AIP) is part of our overall compensation program. It is not a
20 bonus over and above market salaries, and it is needed in order to achieve
21 reasonable market compensation for employees. Mr. O'Connor explains the
22 need for the incentive program for Nuclear employees. Therefore, I have
23 included those costs in our calculation of the revenue requirement.

24

25 Q. IS WISCONSIN'S TREATMENT OF INCENTIVE COMPENSATION RELEVANT?

26 A. As discussed by Company witness Ms. Laura McCarten in her Rebuttal
27 Testimony, one jurisdiction's determination on one issue is not instructive as it

1 does not account for the entirety of circumstances and decisions made in any
2 single case.

3
4 **7. Transmission**

5 Q. WHAT ADJUSTMENT IS PROPOSED WITH RESPECT TO TRANSMISSION EXPENSE?

6 A. Mr. Mugrace proposes using a three-year historical average to determine
7 Transmission expense. He also uses Dr. Pavlovic's lower 1 CP allocator to
8 further decrease the expense.

9
10 Q. DOES THE COMPANY AGREE WITH THIS PROPOSAL?

11 A. No. As discussed by Mr. Foss in his Direct Testimony, the Company's test
12 year Transmission expense represents the cost of providing transmission
13 service to customers in North Dakota. A three-year historical average is not
14 an appropriate methodology to use for determining test year Transmission
15 expenses, as demonstrated by the fact that Mr. Mugrace's proposed
16 Transmission expense is lower than the approved 2011 test year cost and
17 lower than 2012 actual costs. He provides no evidence that the Company's
18 proposed expense for 2013 is not reasonable.

19
20 In addition, as I have explained previously in my Rebuttal Testimony, the
21 Company also disagrees with using a 1 CP demand allocator and the manner
22 in which that 1 CP allocator has been applied. As with other individual costs,
23 Mr. Mugrace applies the 1 CP demand allocator to unadjusted Transmission
24 expense, but does not apply it to all adjustments on a consistent basis. This
25 inconsistent application of Dr. Pavlovic's recommended three-year average 1
26 CP demand allocator results in lower Transmission expense than would have

1 resulted had he applied the 1 CP demand allocator consistently to all
2 Transmission expense, including his recommended adjustments.

3
4 **8. Distribution**

5 Q. WHAT ADJUSTMENT IS PROPOSED WITH RESPECT TO DISTRIBUTION EXPENSE?

6 A. Mr. Mugrace proposes using a three-year historical average to determine the
7 Distribution expense.

8
9 Q. DOES THE COMPANY AGREE WITH THIS PROPOSAL?

10 A. No. As also discussed by Mr. Foss in his Direct Testimony, the Company's
11 test year Distribution expense represents the cost of providing distribution
12 service to customers in North Dakota. In addition, as I have explained
13 previously in my Rebuttal Testimony, a three-year historical average is not an
14 appropriate methodology for determining test year expenses, as demonstrated
15 by the fact that Mr. Mugrace's proposed Distribution expense is nearly equal
16 to the 2011 test year expense and is lower than actual costs for 2011 and 2012.
17 Further, he provides no evidence that the forecasted 2013 expense is not a
18 reasonable level of test year Distribution expense.

19
20 **9. Customer Accounting**

21 Q. WHAT ADJUSTMENT IS PROPOSED WITH RESPECT TO CUSTOMER ACCOUNTING
22 EXPENSE?

23 A. Mr. Mugrace proposes using a three-year historical average to determine the
24 Customer Accounting expense.

25
26 Q. DOES THE COMPANY AGREE WITH THIS PROPOSAL?

1 A. No. As explained previously in my Rebuttal Testimony, the use of a three-
2 year historical average is not appropriate for determining test year expenses, as
3 demonstrated by the fact that Mr. Mugrace proposed Customer Accounting
4 expense is lower than the approved 2011 test year expenses. Additionally, he
5 provides no evidence that the forecasted expense for 2013 is not reasonable.
6

7 **10. Rate Case Expense**

8 Q. WHAT RECOMMENDATION DOES MR. MUGRACE MAKE WITH RESPECT TO
9 RECOVERY OF OUTSIDE LEGAL AND CONSULTING COSTS AS PART OF THE RATE
10 CASE EXPENSE?

11 A. He recommends disallowing those costs on the assumption that the Company
12 does not require assistance in managing this rate case.
13

14 Q. DOES THE COMPANY AGREE?

15 A. No. This issue is discussed more fully by Ms. McCarten. She explains that we
16 balance our internal and external staff to match workloads and expertise.
17 Therefore, I have not removed these costs in calculating the revenue
18 requirement.
19

20 **11. Bad Debt**

21 Q. WHAT ADJUSTMENT IS PROPOSED WITH RESPECT TO BAD DEBT?

22 A. Bad debt is determined by applying a bad debt factor (0.39 percent) to present
23 revenues. Because Mr. Mugrace recommends an increase in the Company's
24 present revenues, he also proposes an increase in test year bad debt expense.
25 Mr. Mugrace's recommended adjustment to bad debt of \$3,000 was developed
26 by multiplying his proposed test year present revenues by the bad debt factor
27 (0.39 percent).

1 Q. DOES THE COMPANY AGREE WITH THIS ADJUSTMENT?

2 A. No. Because I do not recommend an adjustment to present revenues, I do
3 not agree with Mr. Mugrace's adjustment to bad debt expense.

4

5 **12. Customer Service**

6 Q. WHAT ADJUSTMENT IS PROPOSED WITH RESPECT TO CUSTOMER SERVICE
7 EXPENSE?

8 A. Mr. Mugrace proposes using a three-year historical average to determine the
9 Customer Service expense.

10

11 Q. DOES THE COMPANY AGREE WITH THIS PROPOSAL?

12 A. No. As I explained previously in my Rebuttal Testimony, it is not appropriate
13 to use a three-year historical average for determining test year expenses, as
14 demonstrated by the fact that Mr. Mugrace proposed Customer Service
15 expense is lower than the approved 2011 test year expenses. Mr. Mugrace
16 provides no evidence that the forecasted expense for 2013 is not reasonable.

17

18 **13. Administrative and General**

19 Q. WHAT ADJUSTMENT IS PROPOSED WITH RESPECT TO ADMINISTRATIVE AND
20 GENERAL EXPENSE?

21 A. Mr. Mugrace proposes using a three-year historical average to determine test
22 year Administrative and General expense.

23

24 Q. DOES THE COMPANY AGREE WITH THIS PROPOSAL?

25 A. No. As I explained previously in my Rebuttal Testimony, the use of a three-
26 year historical average is not appropriate for determining test year expenses, as
27 demonstrated by the fact that Mr. Mugrace proposed Administrative and

1 General expense is lower than the approved 2011 test year expense. He
2 provides no evidence that the forecasted 2013 expense is not reasonable.

3
4 Q. DOES THREE-YEAR AVERAGING POSE ANY ADDITIONAL PROBLEMS FOR
5 ADMINISTRATIVE AND GENERAL EXPENSES?

6 A. Yes. Mr. Mugrace uses annual data from NDPSC jurisdictional reports filed
7 by the Company to determine the three-year average expense level. However,
8 the Company includes several precedent-based expense adjustments in these
9 filings, such as removing non-recoverable long term incentive and advertising
10 expenses. By using a three-year average of the expense levels from the
11 NDPSC jurisdictional reports as base data, and then applying the test year
12 adjustments proposed in these proceedings, many of the Administrative and
13 General adjustment are double counted. If the Commission determines that
14 the use of a three-year average is appropriate for establishing test year
15 Administrative and General expenses, the basis for the three-year average
16 should exclude all precedent-based adjustments. In addition, the adjustments
17 proposed for the test year should then be based on the same three-year
18 average historical expense, rather than the 2013 budget costs that were
19 proposed by the Company in this case and accepted by Mr. Mugrace as
20 appropriate to adjusting his recommended three-year historical average
21 Administrative and General expense.

22
23 **14. Chamber of Commerce Dues and Charitable Contributions**

24 Q. WHAT ADJUSTMENT IS MADE WITH RESPECT TO CHAMBER OF COMMERCE
25 DUES AND CHARITABLE CONTRIBUTIONS?

1 A. Mr. Mugrace proposes disallowing all Chamber of Commerce dues and
2 charitable contributions. He asserts that these dues and charitable
3 contributions provide no benefit to ratepayers.

4

5 Q. DOES THE COMPANY AGREE WITH THIS ADJUSTMENT?

6 A. No. Ms McCarten explains that we are seeking recovery of 50 percent of the
7 costs for these important mechanisms for supporting the communities and
8 organizations in the areas we serve. Consequently, I have included those costs
9 in our calculation of the revenue requirement.

10

11 **15. Economic Development**

12 Q. WHAT IS THE ISSUE WITH RESPECT TO ECONOMIC DEVELOPMENT?

13 A. Mr. Mugrace recommends denial of the \$173,000 included for Economic
14 Development.

15

16 Q. DOES THE COMPANY AGREE WITH THAT ADJUSTMENT?

17 A. No. As Ms. McCarten explains in her Rebuttal Testimony, the Commission
18 has previously allowed recovery of reasonable economic development costs.
19 We request that the Commission to continue to support our economic
20 development efforts on behalf of the communities we serve, and I have
21 included those costs in our calculation of the revenue requirement.

22

23 **16. Payroll Taxes**

24 Q. WHY DID MR. MUGRACE MAKE AN ADJUSTMENT TO PAYROLL TAXES?

25 A. As discussed above, Mr. Mugrace proposes disallowing all incentive
26 compensation. This recommended disallowance would, in turn, result in
27 lower payroll taxes of \$112,000.

1 Q. IS THIS ADJUSTMENT APPROPRIATE?

2 A. If the Commission accepts the Company's position on the recovery of
3 incentive compensation payments, this adjustment becomes unnecessary, and
4 I have not included it in calculating our revenue requirement.

5

6 **17. Federal and State Income Taxes**

7 Q. DID MR. MUGRACE CALCULATE A LEVEL OF FEDERAL AND STATE INCOME
8 TAXES TO BE INCLUDED IN THE TEST YEAR?

9 A. Yes, Mr. Mugrace included a calculation of both Federal and State Income
10 Taxes in his Schedule DM-26.

11

12 Q. DID THE COMPANY REVIEW MR. MUGRACE SCHEDULE DM-26, AND DO YOU
13 HAVE ANY ISSUES WITH THE CALCULATIONS OF FEDERAL AND STATE INCOME
14 TAXES TO BE INCLUDED IN THE TEST YEAR?

15 A. Yes, the Company reviewed Mr. Mugrace's calculations and identified an error
16 in his Schedule DM-26 calculation of Federal Income Taxes. The schedule
17 takes (\$-5.559 million) for State Taxable Income (DM-26 Line 16 under the
18 Consultants' adjustments) and subtracts (\$286,000) for State Income Taxes
19 (DM-26 Line 18) to equal (\$+5.849 million) of Federal Taxable Income
20 (reported on DM-26 Line 21), which reverses the signs on the subtraction as
21 well as the result. This resulted in a positive Federal Taxable Income of
22 \$5.845 million upon which the Federal Income Taxes was based. The proper
23 Federal Taxable Income should be (\$-5.273 million) calculated by taking the
24 State Taxable Income (\$-5.559 million) and subtracting the State Income
25 Taxes (\$-286,000) [(\$-5.559 million) - (\$-286,000) = (\$-5.273 million)].

26

1 Q. WHAT IS THE IMPACT OF THE ERROR IN MR. MUGRACE'S INCOME TAX
2 CALCULATION?

3 A. The impact of the error in the income tax calculation results in an
4 overstatement of the revenue requirements for the test year. The Company
5 estimates that this error overstated the test year revenue requirements under
6 the Consultants' adjustments by approximately \$6.3 million.

7

8 Q. DOES THIS ERROR NEED TO BE CORRECTED IN MR. MUGRACE'S CALCULATION
9 OF THE REVENUE REQUIRMENT FOR THE TEST YEAR?

10 A. For purposes of correcting the record in this case, Mr. Mugrace's testimony
11 and schedules impacted by this error should be corrected. However, the final
12 calculation of Federal and State Income Taxes to be included in the test year
13 will be a function of the final approved levels of revenue, expense, rate base
14 and weighted cost of capital approved by the Commission.

15

16 **18. Cash Working Capital**

17 Q. DID MR. MUGRACE RECOMMEND ANY ADJUSTMENT TO CASH WORKING
18 CAPITAL FOR THE TEST YEAR?

19 A. Yes, Mr. Mugrace included a recalculation of Cash Working Capital (CWC)
20 based upon applying his recommended adjustments for revenues, O&M
21 expenses, and taxes to the Company cash working capital formula from the
22 Cost of Service model.

23

24 Q. DOES THE COMPANY AGREE WITH THE CWC CALCULATIONS PROPOSED BY
25 MR. MUGRACE?

26 A. Not completely. The Company agrees with the calculation methodology, but
27 not with the amount calculated by Mr. Mugrace. The final level of CWC to be

1 included in this proceeding is a function of the final Commission approved
2 revenue and expenses and tax calculations. This calculation will need to be
3 revised after the Commission determines the final revenue requirement as
4 these decisions will impact the level of CWC. Once the final adjustments have
5 been ordered, the Company will recalculate the CWC level to be included in
6 final rates. The calculation of the final CWC level is historically performed as
7 part of a compliance filing proposing final rates.

8
9 **19. Net Operating Loss**

10 Q. DID MR. MUGRACE RECOMMEND ANY ADJUSTMENT TO THE NET OPERATING
11 LOSS CALCULATION FOR THE TEST YEAR?

12 A. Yes, Mr. Mugrace included a calculation of test year Net Operating Loss
13 (NOL) by prorating the Company's original NOL calculation as filed to his
14 recommended level of rate base.

15
16 Q. DOES THE COMPANY AGREE WITH THE NOL PROPOSED BY MR. MUGRACE?

17 A. No, the Company does not agree with the NOL calculated by Mr. Mugrace.
18 The final level of NOL to be included in this proceeding is a function of the
19 final Commission approved revenue and expenses and tax calculations. It is
20 not a simple proration from the filed NOL downward to the new rate base. It
21 is a function of the beginning deferred tax asset, current year application of tax
22 credits based upon Commission ordered revenues and expenses, and the test
23 year current and deferred income tax expense calculations. As with CWC, this
24 calculation will need to be revised after the Commission determines the final
25 revenue requirement. The calculation of the final NOL level will be
26 performed as part of a compliance filing proposing final rates.

27

1 A. Yes, the Company identified and proposed 10 updates or data corrections
2 subsequent to the initial filing. These adjustments were indentified and
3 discussed in the Company's data response to NDPSC-5-026, as supplemented.
4

5 Q. WERE ANY OF THE COMPANY RECOMMENDED CORRECTIONS AND UPDATE
6 ADJUSTMENTS AGREED TO BY MR. MUGRACE?

7 A. Yes, based upon Mr. Mugrace's review and analysis of the information filed by
8 the Company, the following Company proposed corrections and update
9 adjustments were agreed to by Mr. Mugrace.

- 10 • Removal of the Black Dog Remediation Adjustment
- 11 • AFUDC Correction Adjustment
- 12 • FAS 106 Data Correction Adjustment
- 13 • Incentive Compensation Correction Update Adjustment
- 14 • Monticello License In-Service Update Adjustment
- 15 • Capital No Longer in the Test Year Update Adjustment
- 16 • Sherco 3 Online Date Update Adjustment
- 17 • Pension Calculation Update Adjustment
- 18 • Active Health Care Update Adjustment
- 19 • Property Tax Update Adjustment

20

21 **B. Wind2Battery**

22 Q. DR. PAVLOVIC PROPOSES DISALLOWING COST RECOVERY FOR THE
23 WIND2BATTERY PROJECT. DOES THE COMPANY ACCEPT THAT
24 RECOMMENDATION?

25 A. Yes. While we continue to believe that this was a reasonable project with
26 potential important benefits, we will not oppose this adjustment, and I have

1 included a (\$19,000) adjustment in our proposed test year revenue
2 requirement.

3
4 **VII. COMPLIANCE AND REPORTING**

5
6 **A. Corporate Aviation**

7 Q. WHAT DOES MR. MUGRACE PROPOSE WITH RESPECT TO THE USE OF
8 CORPORATE AIRCRAFT?

9 A. First, he proposes freezing the corporate aircraft budget at the current level of
10 \$104,000, and limiting recovery to 50 percent (\$52,000). He also proposes a
11 number of annual reporting requirements and future rate case requirements.

12
13 Q. WHAT IS YOUR RESPONSE?

14 A. We not believe it is appropriate to freeze the budget for this valuable asset.
15 The alternatives to corporate aircraft are commercial aircraft (whose costs are
16 not frozen). In addition, the Company already makes extensive use of
17 teleconferencing and video conferencing where appropriate. Regarding
18 reporting requirements, we are aware of the need to justify this expense in rate
19 cases and will continue to do so in future rate cases. If the Commission would
20 find it beneficial to receive annually the information recommended by Mr.
21 Mugrace, we will, of course, provide it. Mr. Mugrace's recommendation
22 would include tracking the use of the Company's Aviation policy and
23 reporting on its expenses, as well as adherence and policy changes as part of its
24 earnings reports. He also recommends that we provide evidence that the
25 Company is using alternatives such as video-conferencing and other
26 electronically available devices to decrease the need for travel and to allow for
27 more usage of commercial travel.

1 **B. Cell Phone Expense**

2 Q. WHAT DOES MR. MUGRACE PROPOSE WITH RESPECT TO CELL PHONE
3 EXPENSE?

4 A. He accepts the Company's \$7,000 adjustment reducing cell phone expense.
5 The reduction was the result of a Company audit to make sure cell phone
6 reimbursement was consistently and appropriately applied. Mr. Mugrace
7 further proposes: "the Company annually provide updates with respect to the
8 Company Cellular Phone Plan costs and changes as part of its earnings reports
9 to assure that the Company is consistently seeking out and taking advantage of
10 expense savings that can minimize the cost impact to the ratepayers in the
11 North Dakota jurisdiction"¹³. As with the Corporate Aircraft information
12 recommendation, we are aware of the need to justify our expenses in rate
13 cases and will continue to do so in future rate cases. If the Commission would
14 find receiving the suggested information in the annual reports beneficial, we
15 will, of course, provide it.

16
17 **C. Pension Update**

18 Q. MR. MUGRACE SUPPORTS THE COMPANY'S UPDATED PENSION EXPENSE AND
19 PROPOSES ANNUAL REPORTING. DOES THE COMPANY ACCEPT THAT
20 REPORTING OBLIGATION?

21 A. Yes, if the Commission believes it would be beneficial. More specifically, Mr.
22 Mugrace requests an annual report on our pension expense along with a
23 description of the two smoothing alternatives Ms. McCarten identified in her
24 Direct Testimony as being available for consideration.

25
26

¹³ Mugrace Direct at 67-68.

1 **VIII. INTERIM RATES**

2
3 Q. HAS MR. MUGRACE RAISED ANY ISSUES AFFECTING THE RECOVERY OF
4 INTERIM RATES?

5 A. Yes. Mr. Mugrace proposes changing interim rates to reflect the adjustment
6 made by the Company for Sherco 3 in final rates, and requests that the
7 Company provide an update on the collection of interim rate revenues
8 through June 2013.

9
10 Q. DO YOU AGREE WITH THESE PROPOSALS?

11 A. No. First, I do not agree that the final revenue requirement will necessarily be
12 less than the interim revenue requirement. Based on the Company's Rebuttal
13 Testimony, the final revenue requirement will be \$14.884 million, which is
14 slightly higher than the interim revenue requirement of \$14.704 million.
15 Therefore, the Company's adjustments do not support a reduction in interim
16 rates. Second, when the Commission determines our final revenue
17 requirement, we will implement any required interim rate refunds as soon as
18 possible. A separate accelerated partial interim rate refund, while possible,
19 would likely be confusing to customers and it would be difficult for the
20 Company to administer two separate interim refunds.

21
22 In any event, there is no basis for making an interim rate refund based on the
23 Sherco 3 adjustment alone. Nor do we believe there is value in providing
24 interim revenue information through June 2013 because the interim refund
25 will be based on the entire period the interim rates are in effect.
26

1 **IX. CONCLUSION**

2

3 Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

4 A. I recommend the Commission determine an overall retail revenue requirement
5 of \$197.608 million and a 2013 revenue deficiency of \$14.884 million for the
6 Company's North Dakota jurisdictional electric operations, determined by the
7 cost of service for the 2013 test year.

8

9 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

10 A. Yes, it does.

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

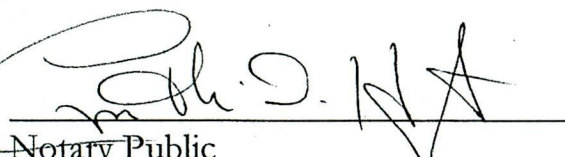
6 In the Matter of the Application of Northern)
7 States Power Company, a Minnesota Corporation)
8 For Authority to Increase Rates for Electric Service) Case No. PU-12-813
9 in North Dakota)

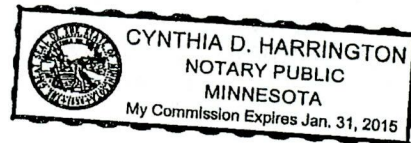
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11
12
13 AFFIDAVIT OF
14 Anne E. Heuer
15
16

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

22
23
24 
25 _____
26 Anne E. Heuer
27
28
29

30 Subscribed and sworn to before me, this ^{9th} day of August, 2013.

31
32 
33 _____
34 Notary Public
35 My Commission Expires: 1-31-2015
36



Index of Schedules

Index of Financial Schedules	Schedule 1
Summary of Revenue Requirements	Schedule 2
Comparison of Detailed Rate Base	Schedule 3
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2013 Rebuttal Bridge Schedule	Schedule 5
Cost of Service Studies - Rebuttal Test Year	Schedule 6

Northern States Power Company
Electric Utility - State of North Dakota
SUMMARY OF REVENUE REQUIREMENTS
Rebuttal Test Year Ending December 31, 2013
(\$000's)

Case No. PU-12-813
Exhibit___(AEH-2) Schedule 2
Page 1 of 1

<u>Line</u>	<u>Description</u>	Rebuttal Test Year 2013 <u>As Adjusted</u>
1	Average Rate Base	\$375,810
2	Operating Income (Before AFUDC)	\$19,836
3	Allowance for Funds Used During Construction	\$0
4	Total Available for Return (Line 2 + Line 3 + Rounding)	\$19,836
5	Overall Rate of Return (Line 4 / Line 1)	5.28%
6	Required Rate of Return	7.72%
7	Operating Income Requirement (Line 1 x Line 6)	\$29,013
8	Income Deficiency (Line 7 - Line 4)	\$9,176
9	Gross Revenue Conversion Factor	1.62201
10	Revenue Deficiency (Line 8 x Line 9)	\$14,884
11	Retail Related Revenue Under Present Rates	\$182,724
13	Percentage Increase Needed in Overall Revenue (Line 10 / Line 11)	8.15%

Northern States Power Company
Electric Utility - State of North Dakota
Comparison of Detail Rate Base Components
(\$000's)

Case No. PU-12-813
 Exhibit (AEH-2) Schedule 3
 Page 1 of 1

Line No. Description	Proposed 2013 Test Year As Filed (A)	Changes (B)	Rebuttal 2013 Test Year As Updated (C) = (B) + (A)
Electric Plant as Booked			
1 Production	\$537,079	(\$2,129)	\$534,950
2 Transmission	136,211	129	136,340
3 Distribution	138,686	0	138,686
4 General	29,097	0	29,097
5 Common	29,899	0	29,899
6 TOTAL Utility Plant in Service	<u>\$870,972</u>	<u>(\$2,000)</u>	<u>\$868,972</u>
Reserve for Depreciation			
7 Production	\$289,499	(\$339)	\$289,160
8 Transmission	38,787	3	38,790
9 Distribution	62,947	0	62,947
10 General	11,053	0	11,053
11 Common	17,303	0	17,303
12 TOTAL Reserve for Depreciation	<u>\$419,589</u>	<u>(\$336)</u>	<u>\$419,253</u>
Net Utility Plant in Service			
13 Production	\$247,580	(\$1,790)	\$245,789
14 Transmission	97,424	126	97,550
15 Distribution	75,739	0	75,739
16 General	18,044	0	18,044
17 Common	12,596	0	12,596
18 Net Utility Plant in Service	<u>\$451,383</u>	<u>(\$1,664)</u>	<u>\$449,719</u>
19 Utility Plant Held for Future Use	\$0	\$0	\$0
20 Construction Work in Progress	\$2,037	\$0	\$2,037
21 Less: Accumulated Deferred Income Taxes	\$92,784	(\$267)	\$92,517
22 Cash Working Capital	(\$926)	(\$150)	(\$1,076)
Other Rate Base Items:			
23 Materials and Supplies	\$7,613	\$0	\$7,613
24 Fuel Inventory	5,899	0	5,899
25 Non-Plant Assets & Liabilities	(1,809)	(291)	(2,100)
26 Prepayments	1,050	0	1,050
27 Nuclear Outage Amortization	5,018	0	5,018
28 Customer Advances	(18)	0	(18)
29 Customer Deposits	(213)	0	(213)
30 Other Working Capital	398	0	398
31 Total Other Rate Base Items	<u>\$17,938</u>	<u>(\$291)</u>	<u>\$17,647</u>
32 Total Average Rate Base	<u><u>\$377,648</u></u>	<u><u>(\$1,839)</u></u>	<u><u>\$375,810</u></u>

Northern States Power Company
 Electric Utility - State of North Dakota
 Comparison Statement of Operating Income
 Test Year Ending December 31, 2013
 (Dollars in Thousands)

Case No. PU-12-813
 Exhibit (AEH-2) Schedule 4
 Page 1 of 1

Line No.	Description	Proposed 2013 Test Year As Filed (A)	Changes (B)	Rebuttal 2013 Test Year As Updated (C) = (B) + (A)
Operating Revenues				
1	Retail	\$182,724		\$182,724
2	Interdepartmental	0		\$0
3	Other Operating	45,502		\$45,502
4	Total Operating Revenues	<u>\$228,226</u>	<u>\$0</u>	<u>\$228,226</u>
Expenses				
Operating Expenses:				
5	Fuel & Purchased Energy	\$82,971		\$82,971
6	Power Production	46,221	(227)	\$45,994
7	Transmission	14,031		\$14,031
8	Distribution	6,763		\$6,763
9	Customer Accounting	4,286		\$4,286
10	Customer Service & Information	457		\$457
11	Sales, Econ Dvlp & Other	173		\$173
12	Administrative & General	14,822	(10)	\$14,812
13	Total Operating Expenses	<u>\$169,724</u>	<u>(\$237)</u>	<u>\$169,487</u>
14	Depreciation	\$22,563	(\$592)	\$21,971
15	Amortizations	373		\$373
Taxes:				
16	Property	\$7,940	\$174	\$8,114
17	Deferred Income Tax & ITC	12,760	(539)	\$12,221
18	Federal & State Income Tax	(6,481)	773	(\$5,708)
19	Payroll & Other	1,931		\$1,931
20	Total Taxes	<u>\$16,151</u>	<u>\$408</u>	<u>\$16,559</u>
21	Total Expenses	<u>\$208,811</u>	<u>(\$421)</u>	<u>\$208,390</u>
22	AFUDC	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>
23	Total Operating Income	<u><u>\$19,415</u></u>	<u><u>\$421</u></u>	<u><u>\$19,836</u></u>

Northern States Power Company
 Electric Utility - State of North Dakota
 RATE BASE ADJUSTMENT SCHEDULES
 2013 Rebuttal Test Year versus Proposed Test Year
 (\$000's)

Line No.	Description <u>Work Paper Reference</u>	Proposed 2013 Test Year	Black Dog	AFUDC Fix	AFUDC Misso	FAS 106 Fix	Montl Lic	Out in 2013	Sherco 3	Wind 2 Battery	CWC Adj	NOL Adj	Total
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	Electric Plant as Booked												
	Production	\$537,079					(\$1,337)	(\$579)	\$0	(\$213)			\$534,950
2	Transmission	\$136,211		\$132	(\$3)								\$136,340
3	Distribution	\$138,686											\$138,686
4	General	\$29,097											\$29,097
5	Common	\$29,899											\$29,899
6	TOTAL Utility Plant in Service	\$870,972	\$0	\$132	(\$3)	\$0	(\$1,337)	(\$579)	\$0	(\$213)	\$0	\$0	\$868,972
	Reserve for Depreciation												
7	Production	\$289,499	(\$248)				(\$28)	\$2	(\$11)	(\$54)			\$289,160
8	Transmission	\$38,787		\$3	\$0								\$38,790
9	Distribution	\$62,947											\$62,947
10	General	\$11,053											\$11,053
11	Common	\$17,303											\$17,303
12	TOTAL Reserve for Depreciation	\$419,589.0	(\$248)	\$3	\$0	\$0	(\$28)	\$2	(\$11)	(\$54)	\$0	\$0	\$419,253
	Net Utility Plant in Service												
13	Production	\$247,580	\$248			\$0	(\$1,309)	(\$581)	\$11	(\$160)	\$0	\$0	\$245,789
14	Transmission	\$97,424		\$129	(\$3)								\$97,550
15	Distribution	\$75,739											\$75,739
16	General	\$18,044											\$18,044
17	Common	\$12,596											\$12,596
18	Net Utility Plant in Service	\$451,383	\$248	\$129	(\$3)	\$0	(\$1,309)	(\$581)	\$11	(\$160)	\$0	\$0	\$449,719
19	Utility Plant Held for Future Use	\$0											\$0
20	Construction Work in Progress	\$2,037											\$2,037
21	Less: Accumulated Deferred Income Taxes	\$92,784	\$102	(\$8)	(\$3)		(\$2)	\$51	\$5	(\$58)		(\$354)	\$92,517
22	Cash Working Capital	(\$926)									(\$150)		(\$1,076)
	Other Rate Base Items:												
23	Materials and Supplies	\$7,613											\$7,613
24	Fuel Inventory	\$5,899											\$5,899
25	Non-Plant Assets & Liabilities	(\$1,809)				(\$291)							(\$2,100)
26	Prepayments	\$1,050											\$1,050
27	Deferred Revenues - Nuc Outage	\$0											\$0
28	Nuclear Outage Amortization	\$5,018											\$5,018
29	Customer Advances	(\$18)											(\$18)
30	Customer Deposits	(\$213)											(\$213)
31	Other Working Capital	\$398											\$398
32	Total Other Rate Base Items	\$17,938	\$0	\$0	\$0	(\$291)	\$0	\$0	\$0	\$0	\$0	\$0 #	\$17,647
33	Total Average Rate Base	\$377,648	\$147	\$137	\$1	(\$291)	(\$1,307)	(\$632)	\$6	(\$102)	(\$150)	\$354 #	\$375,810

Line No.	Description	Proposed 2013 Test Year	Remove BD Adj	AFUDC Fix	AFUDC Miso	FAS 106 Fix	Inc Comp Fix	Montl Lic	Out in 2013	Sherco 3	Pension Update	Health Care Update	Prop Tax Update
			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Operating Revenues													
1	Retail	\$182,724	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2	CIP Revenue Adjustment	\$0	0	0	0	0	0	0	0	0	0	0	0
3	Interdepartmental	\$0	0	0	0	0	0	0	0	0	0	0	0
4	Other Operating	\$45,502	0	0	0	0	0	0	0	0	0	0	0
5	Total Operating Revenues	\$228,226	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Expenses													
Operating Expenses:													
6	Fuel & Purchased Energy	\$82,971	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
7	Power Production	\$46,221	0	0	0	0	0	0	0	(227)	0	0	0
8	Transmission	\$14,031	0	0	0	0	0	0	0	0	0	0	0
9	Distribution	\$6,763	0	0	0	0	0	0	0	0	0	0	0
10	Customer Accounting	\$4,286	0	0	0	0	0	0	0	0	0	0	0
11	Customer Service & Information	\$457	0	0	0	0	0	0	0	0	0	0	0
12	Sales, Econ Dvlp & Other	\$173	0	0	0	0	0	0	0	0	0	0	0
13	Administrative & General	\$14,822	0	0	0	0	(6)	0	0	0	246	(250)	0
14	Total Operating Expenses	\$169,724	\$0	\$0	\$0	\$0	(\$6)	\$0	\$0	(\$227)	\$246	(\$250)	\$0
15	Depreciation	\$22,563	(\$497)	\$5	\$0	\$0	\$0	(\$56)	(\$7)	(\$22)	\$0	\$0	\$0
16	Amortization	\$373	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Taxes:													
17	Property	\$7,940	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$174
18	Deferred Income Tax & ITC	\$12,760	203	(8)	(3)	0	0	(4)	(34)	9	0	0	0
19	Federal & State Income Tax	(\$6,481)	(2)	28	(0)	3	2	52	3	87	(94)	96	(67)
20	Payroll & Other	\$1,931	0	0	0	0	0	0	0	0	0	0	0
21	Total Taxes	\$16,150	\$201	\$20	(\$3)	\$3	\$2	\$48	(\$31)	\$96	(\$94)	\$96	\$107
22	Total Expenses	\$208,811	(\$296)	\$25	(\$3)	\$3	(\$4)	(\$8)	(\$38)	(\$153)	\$152	(\$154)	\$107
23	Allowance for Funds Used During Construction	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
24	Total Operating Income	\$19,415	\$296	(\$25)	\$3	(\$3)	\$4	\$8	\$38	\$153	(\$152)	\$154	(\$107)
Calculation of Revenue Requirements													
25	Rate Base	\$377,648	\$147	\$137	\$1	(\$291)	\$0	(\$1,307)	(\$632)	\$6	\$0	\$0	\$0
26	Required Operating Income	\$29,834	12	11	0	(24)	0	(109)	(52)	1	0	0	0
27	Operating Income	\$19,415	296	(25)	3	(3)	4	8	38	153	(152)	154	(107)
28	Revenue Deficiency	\$10,419	(283)	36	(3)	(21)	(4)	(116)	(90)	(153)	152	(154)	107
29	Revenue Requirements	\$16,900	(\$460)	\$59	(\$5)	(\$34)	(\$6)	(\$189)	(\$147)	(\$247)	\$246	(\$250)	\$174
Calculation of Income Taxes													
30	Operating Revenue	\$228,226	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
31	- Operating Exp	\$169,724	0	0	0	0	(6)	0	0	(227)	246	(250)	0
32	- Amortizations	\$373	0	0	0	0	0	0	0	0	0	0	0
33	- Taxes oth than Inc	\$9,871	0	0	0	0	0	0	0	0	0	0	174
34	Operating Income before Adjs	\$48,258	\$0	\$0	\$0	\$0	\$6	\$0	\$0	\$227	(\$246)	\$250	(\$174)
35	Additions to Income	\$14,964	\$0	\$84	\$0	\$0	\$0	\$8	(\$228)	\$0	\$0	\$0	\$0
36	Deduct from Income	\$71,323	\$0	\$7	\$0	\$0	\$0	(\$91)	(\$218)	\$0	\$0	\$0	\$0
37	Debt Synchronization	\$8,799	\$4	\$4	\$0	(\$8)	\$0	(\$37)	(\$18)	\$0	\$0	\$0	\$0
38	State Taxable Income	(\$16,900)	(\$4)	\$73	(\$0)	(\$8)	\$6	\$136	\$8	\$227	(\$246)	\$250	(\$174)
39	State Income Tax before Credits	(\$870)	(\$0)	\$4	(\$0)	\$0	\$0	\$7	\$0	\$12	(\$13)	\$13	(\$9)
40	State Tax Credits	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
41	Federal Taxable Income	(\$16,029)	(\$4)	\$69	(\$0)	\$8	\$6	\$129	\$7	\$215	(\$233)	\$237	(\$165)
42	Fed Income Tax before Credits	(\$5,610)	(\$1)	\$24	(\$0)	\$3	\$2	\$45	\$3	\$75	(\$82)	\$83	(\$58)
43	Federal Tax Credits	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
44	Income Tax	(\$6,481)	(\$2)	\$28	(\$0)	\$3	\$2	\$52	\$3	\$87	(\$94)	\$96	(\$67)

Line No.	Description	Wind 2 Battery	NOL	CWC	ROE	Cost of Capital	Rebuttal Test Year
		(12)	(13)	(14)	(15)	(16)	(17)
Operating Revenues							
1	Retail	\$0	\$0	\$0	\$0	\$0	\$182,724
2	CIP Revenue Adjustment	0	0	0	0	0	0
3	Interdepartmental	0	0	0	0	0	0
4	Other Operating	0	0	0	0	0	45,502
5	Total Operating Revenues	\$0	\$0	\$0	\$0	\$0	\$228,226
Expenses							
Operating Expenses:							
6	Fuel & Purchased Energy	\$0	\$0	\$0	\$0	\$0	\$82,971
7	Power Production	0	0	0	0	0	45,994
8	Transmission	0	0	0	0	0	14,031
9	Distribution	0	0	0	0	0	6,763
10	Customer Accounting	0	0	0	0	0	4,286
11	Customer Service & Information	0	0	0	0	0	457
12	Sales, Econ Dvlp & Other	0	0	0	0	0	173
13	Administrative & General	0	0	0	0	0	14,812
14	Total Operating Expenses	\$0	\$0	\$0	\$0	\$0	\$169,487
15	Depreciation	(\$15)	\$0	\$0	\$0	\$0	\$21,971
16	Amortization	\$0	\$0	\$0	\$0	\$0	\$373
Taxes:							
17	Property	\$0	\$0	\$0	\$0	\$0	\$8,114
18	Deferred Income Tax & ITC	6	(709)	0	0	0	12,221
19	Federal & State Income Tax	6	661	2	(0)	(4)	(5,708)
20	Payroll & Other	0	0	0	0	0	1,931
21	Total Taxes	\$12	(\$48)	\$2	(\$0)	(\$4)	\$16,558
22	Total Expenses	(\$3)	(\$48)	\$2	(\$0)	(\$4)	\$208,390
23	Allowance for Funds Used During Construction	\$0	\$0	\$0	\$0	\$0	\$0
24	Total Operating Income	\$3	\$48	(\$2)	\$0	\$4	\$19,836
Calculation of Revenue Requirements							
25	Rate Base	(\$102)	\$354	(\$150)	\$0	\$0	\$375,810
26	Required Operating Income	(8)	29	(12)	(718)	\$48	\$29,013
27	Operating Income	3	48	(2)	0	4	\$19,836
28	Revenue Deficiency	(12)	(18)	(11)	(718)	45	\$9,176
29	Revenue Requirements	(\$19)	(\$30)	(\$18)	(\$1,164)	\$73	\$14,884
Calculation of Income Taxes							
30	Operating Revenue	\$0	\$0	\$0	\$0	\$0	\$228,226
31	- Operating Exp	0	0	0	0	0	169,487
32	- Amortizations	0	0	0	0	0	373
33	- Taxes oth than Inc	0	0	0	0	0	10,045
34	Operating Income before Adjs	\$0	\$0	\$0	\$0	\$0	\$48,321
35	Additions to Income	\$0	\$0	\$0	\$0	\$0	\$14,828
36	Deduct from Income	(\$12)	(1,734)	\$0	\$0	\$0	\$69,276
37	Debt Synchronization	(\$3)	\$10	(\$4)	\$0	\$9	\$8,757
38	State Taxable Income	\$15	\$1,723	\$4	(\$0)	(\$9)	(\$14,884)
39	State Income Tax before Credits	\$1	\$89	\$0	(\$0)	(\$0)	(\$767)
40	State Tax Credits	\$0	\$0	\$0	\$0	\$0	\$0
41	Federal Taxable Income	\$14	\$1,635	\$4	(\$0)	(\$9)	(\$14,116)
42	Fed Income Tax before Credits	\$5	\$572	\$1	(\$0)	(\$3)	(\$4,940)
43	Federal Tax Credits	\$0	\$0	\$0	\$0	\$0	\$0
44	Income Tax	\$6	\$661	\$2	(\$0)	(\$4)	(\$5,708)

ROE = 5.61%
Deficiency = \$14,884
% Increase = 8.15%
Required ROE = 10.25%

Case No. PU-12-813

Exhibit___(AEH-2) Schedule 6

Page 1 of 6

Northern States Power Company (ND)
Electric Utility - North Dakota Retail Jurisdiction
Cost of Service Study
Rebuttal 2013 Test Year

Summary Reports

Northern States Power Company (ND)
 Electric Utility - North Dakota Retail Jurisdiction
 Cost of Service Study
 Rebuttal 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	14,470,972	15,938,776	15,204,874	825,406	912,538	868,972	13,645,566	15,026,238	14,335,902
2 Depreciation Reserve	<u>(7,023,949)</u>	<u>(7,391,195)</u>	<u>(7,207,572)</u>	<u>(407,770)</u>	<u>(430,736)</u>	<u>(419,253)</u>	<u>(6,616,179)</u>	<u>(6,960,459)</u>	<u>(6,788,319)</u>
3 Net Utility Plant	7,447,023	8,547,581	7,997,302	417,636	481,802	449,719	7,029,387	8,065,779	7,547,583
4 C.W.I.P.	35,101	31,595	33,348	2,163	1,912	2,037	32,938	29,683	31,311
5 Accumulated Deferred Taxes	(1,589,116)	(1,819,076)	(1,704,096)	(86,346)	(98,688)	(92,517)	(1,502,770)	(1,720,388)	(1,611,579)
Other Rate Base:									
6 Cash Working Capital	(46,021)	(46,021)	(46,021)	(1,076)	(1,076)	(1,076)	(44,945)	(44,945)	(44,945)
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	(51,681)	(17,203)	(34,442)	(3,151)	(1,049)	(2,100)	(48,530)	(16,154)	(32,342)
10 Prepays & Other	91,497	108,869	100,183	5,704	6,766	6,235	85,793	102,103	93,948
11 Total Rate Base	6,103,052	7,021,995	6,562,523	348,442	403,180	375,810	5,754,610	6,618,815	6,186,713

Income Statement Summary

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>
<u>Operating Revenues</u>			
1 Retail	3,049,972	182,724	2,867,248
2 CIP Adjustment to Program Costs			0
3 Interdepartmental	540	-	540
4 Other Operating	770,321	45,502	724,819
5 Gross Earnings Tax			0
6 Total Operating Revenues	3,820,833	228,226	3,592,607
<u>Expenses</u>			
Operating Expenses:			
7 Fuel & Purchased Energy	1,278,735	82,971	1,195,764
8 Power Production	751,131	45,994	705,137
9 Transmission	241,353	14,031	227,322
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	233,008	14,812	218,196
15 Total Operating Expenses	2,709,985	169,487	2,540,498
16 Depreciation	361,126	21,971	339,155
17 Amortization	23,144	373	22,771
Taxes:			
18 Property	167,759	8,114	159,645
19 Gross Earnings	0	-	0
20 Deferred Income Tax & ITC	227,083	12,221	214,862
21 State & Federal Income (see Page 3)	(91,697)	(5,708)	(85,990)
22 Payroll & Other	31,388	1,931	29,457
23 Total Taxes	334,533	16,559	317,975
24 Total Expenses	3,428,788	208,390	3,220,398
25 AFUDC	0	0	(0)
26 Total Operating Income	392,045	19,836	372,209

Income Tax Summary

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>	
<u>Income Before Taxes</u>				
1	Total Operating Revenues	3,820,833	228,226	3,592,607
2	less: Total Operating Expenses	(2,709,985)	(169,487)	(2,540,498)
3	Book Depreciation & Amortization	(384,270)	(22,344)	(361,926)
4	Taxes (Other Than Current Income)	(426,230)	(22,266)	(403,964)
5	Total Before Tax Book Income	300,348	14,129	286,219
<u>Tax Additions</u>				
6	Book Depreciation	361,126	21,971	339,155
7	Deferred Income Taxes & ITC	227,083	12,221	214,862
8	Nuclear Fuel Burn (ex D&D)	120,368	7,249	113,119
9	Nuclear Outage Accounting	74,486	4,664	69,822
10	Avoided Tax Interest	49,764	2,915	46,849
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	Total Tax Additions	832,827	49,020	783,807
<u>Tax Deductions</u>				
18	Debt Interest Expense	152,907	8,756	144,150
19	Tax Depreciation & Removal	1,116,705	67,053	1,049,652
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	36,449	2,223	34,226
25	Net Preferred Stock Deduction	0	0	0
26	Total Tax Deductions	1,306,060	78,032	1,228,028
27	State Taxable Income	(172,885)	(14,883)	(158,002)
28	State Income Tax Rate	9.07%	5.15%	N/A
29	State Taxes before Credits	(15,673)	(767)	(14,906)
30	State Credits	0	0	0
31	Total State Income Taxes	(15,673)	(767)	(14,906)
32	Federal Taxable Income	(157,212)	(14,117)	(143,096)
33	Federal Income Tax Rate	35.00%	35.00%	35.00%
34	Federal Tax before Credits	(55,024)	(4,941)	(50,083)
35	Federal Tax Credits	21,000	0	21,000
36	Total Federal Income Taxes	(76,024)	(4,941)	(71,083)
37	Total Federal & State Income Taxes	(91,697)	(5,708)	(85,990)

Revenue Requirement & Return Summary

(Dollars in Thousands)

<u>Capital Structure</u>				<u>Weighted</u>	<u>Composite Income Tax Rates</u>	
	<u>Rate</u>	<u>Ratio</u>	<u>Cost</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	10.2500%	52.5600%	5.3900%	Total North Dakota Composite Tax Rate	38.35%
5	Required Rate of Return			7.7200%	Total Corporate Composite Tax Rate	40.89%

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>
Rate of Return (ROR)			
6	Total Operating Income	392,045	19,836
7	Total Average Rate Base	6,562,523	375,810
8	ROR (Operating Income / Rate Base)	5.97%	5.28%

Return on Equity (ROE)			
9	Total Operating Income	392,045	19,836
10	Debt Interest (Rate Base * Weighted Debt Cost)	(152,907)	(8,756)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0
12	Earnings Available for Common	239,138	11,080
13	Equity Rate Base (Rate Base * Equity Ratio)	3,449,262	197,526
14	ROE (Earnings for Common / Equity Rate Base)	6.93%	5.61%

Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Return)	506,627	29,013
16	Operating Income	392,045	19,836
17	Operating Income Deficiency	114,582	9,176
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.69184	1.62201
19	Revenue Deficiency (Income Deficiency * Conversion Factor)	193,854	14,884

Total Retail Revenue Requirements			
20	Retail Related Revenues	3,050,512	182,724
21	Revenue Deficiency	193,854	14,884
22	Total Retail Revenue Requirements	3,244,366	197,608

23	Percentage Increase (Decrease)	6.35%	8.15%	6.24%
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(Dollars in Thousands)

Rate Base Detail - Cash Working Capital

Expenses	Lead Days	Total Company Electric		ND Retail Electric		All Other	
		Dollars	Dollar x Days	Dollars	Dollar x Days	Dollars	Dollar x Days
Fuel Expenses							
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	37,125	735,282	532,372	10,612,354
Purchased Power							
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
Labor & Related Costs							
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	1,576,697	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	705,637	20,611,657	41,975	1,226,090	663,662	19,385,567
15 Property Tax	355.99	167,759	59,720,526	8,114	2,888,503	159,645	56,832,024
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	(76,024)	(2,793,894)	(4,941)	(181,578)	(71,083)	(2,612,316)
19 State Income Tax	36.75	(15,673)	(575,982)	(767)	(28,173)	(14,906)	(547,809)
20 State Sales Tax Customer Billings	28.99	148,826	4,314,466	0	0	148,826	4,314,466
21 Total Expenses	46.44	2,966,261	137,758,510	173,824	7,479,099	2,792,436	130,279,412
22 Net Annual Expense Amount			377,421		20,491		356,930
Revenues							
23 Computer Billing	100.00%	41.28	3,049,972	125,902,844	182,724	7,542,847	2,867,248
24 Hand Billed	0.00%	41.28	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	114,879	4,716,932	4,863	199,675	110,016	4,517,257
38 Distribution Associated Revenues	41.28	0	0	0	0	0	0
39 Other	41.28	10,533	434,802	95	3,922	10,438	430,881
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	3,820,833	155,809,473	228,226	9,304,387	3,592,607	146,505,086
45 Net Annual Amount			426,875		25,491		401,384
46 Expense / Revenue Factor			0.7763		0.7616		
47 Allocated Revenue Amount			331,400		19,415		
48 Net Cash Working Capital			(46,021)		(1,076)		(44,945)