

Rebuttal Testimony
Kent T. Larson

Before the North Dakota Public Service Commission
State of North Dakota

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

For Authority to Increase Rates for
Electric Service in North Dakota

Case No. PU-07-776
Exhibit___

Policy Testimony

June 13, 2008

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1 **I. INTRODUCTION**

2

3 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

4 A. My name is Kent Larson. My business address is 414 Nicollet Mall,
5 Minneapolis, Minnesota 55401.

6

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

8 A. Yes. I have filed Direct Testimony in this proceeding on behalf of Northern
9 States Power Company (“Xcel Energy” or “the Company”), a Minnesota
10 corporation operating in North Dakota.

11

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

13 A. I am providing the Company’s overall response to the Direct Testimony of
14 Mr. Charles W. King and Mr. Michael J. Majoros, Jr. (collectively the
15 “Consultants”) presented on behalf of the Advocacy Staff of the North
16 Dakota Public Service Commission (the “Commission”). I will also introduce
17 our other witnesses who are presenting Rebuttal Testimony and provide a
18 brief overview of the information they will present.

19

20 My Direct Testimony discusses why adoption of the recommendations of the
21 Consultants would be extremely detrimental to our ability to provide the level
22 of service our North Dakota customers currently enjoy. We appreciate the
23 concerns raised by Advocacy Staff and are committed to working to address
24 them. The recommendations of the Consultants, however, are not an
25 appropriate remedy for those concerns, are not supported by the record of
26 this proceeding, and should not be adopted by the Commission. My Rebuttal

1 Testimony, along with the Rebuttal of other Company witnesses, provides
2 substantial evidence in support of this overall Company recommendation.

3
4 **II. SUMMARY AND ORGANIZATION**

5
6 Q. HAVE YOU REVIEWED THE CONSULTANTS' DIRECT TESTIMONY?

7 A. Yes, I have.

8
9 Q. DO YOU HAVE ANY OVERALL COMMENTS REGARDING THEIR TESTIMONY?

10 A. Yes. Their Direct Testimony indicates concerns regarding nearly all of our
11 recent investments in our system. From my reading of the testimony, these
12 concerns are based on:

- 13 • *A belief that requirements and initiatives in the Minnesota jurisdiction are inappropriate*
14 *and should be paid for exclusively by Minnesota customers.* Mr. King expresses this
15 concern when recommending disallowance of our costs of meeting
16 renewable energy requirements and complying with the Minnesota Mercury
17 Reduction Act (“MMRA”).
- 18 • *Disagreement with the Company’s decision to implement environmental improvements*
19 *prior to the time required by federal law.* Mr. King expresses this concern when
20 recommending denial of our costs associated with our Metropolitan
21 Emissions Reduction Project (“MERP”) and our compliance with MMRA.
- 22 • *Dissatisfaction with the cost-effectiveness of investments the Company has made in*
23 *Minnesota compared to possible investments in North Dakota.* Mr. King expresses
24 this concern when recommending disallowance of costs associated with our
25 investment in the Grand Meadow wind project and transmission associated
26 with carrying wind from Buffalo Ridge.

1 Based on these concerns, the Consultants' overall recommendation of this case
2 is to:

- 3 • Disallow our entire requested rate increase.
- 4 • Reduce current base rates by \$200,000 (although our analysis of the
5 Consultants' recommendations results in a base rate increase of
6 approximately \$4.7 million, as described in Ms. Heuer's Rebuttal
7 Testimony).
- 8 • Consider further cost disallowances in the fuel clause adjustment ("FCA").

9
10 Q. WHAT IS THE COMPANY'S REACTION TO THIS RECOMMENDATION?

11 A. We certainly understand the concerns expressed in the Direct Testimony of
12 the Consultants. We can also appreciate the policy concerns that stem from
13 being asked to approve recovery of costs associated with investments that the
14 Commission did not separately approve and with which it may disagree.

15
16 These concerns also indicate, that as a Company, we can do more to facilitate
17 greater involvement of the Commission in our resource planning process and
18 pursue investments in generating resources located within North Dakota. As
19 you will see throughout our Rebuttal Testimony, we are working to remedy
20 this issue, and to demonstrate this, we are providing substantial information
21 regarding: (i) each of our recent investments; (ii) our efforts to plan for a
22 system that benefits all of our customers; and (iii) our plans for complying
23 with requirements in all jurisdictions in the most efficient and cost-effective
24 manner possible. We are also proposing a process for addressing resource
25 planning in North Dakota to ensure we continue to address these concerns in
26 an on-going manner.

27

1 But while we appreciate the concerns that have been raised and are committed
2 to working to address them, we also believe that the Commission should not
3 resolve our rate case on the basis of broader policy concerns that did not
4 originate with the Company. Rather, we believe that the Commission must
5 consider our rate request in accordance with its standard ratemaking principles
6 and focus on the overall prudence of our decisions and costs and facts of the
7 case. In our view, the drastic remedies that have been recommended by the
8 Consultants are far out of proportion to any concerns related to the
9 Company's decisions or costs, and lack a solid factual basis in the record for
10 this proceeding.

11
12 Q. WHY DO YOU BELIEVE THAT THE CONSULTANTS' RECOMMENDATIONS ARE
13 NOT AN APPROPRIATE RESPONSE TO THE CONCERNS RAISED?

14 A. I believe that the recommendation to disallow our entire requested increase
15 and to instead reduce current rates is not an appropriate response to the
16 concerns raised because:

- 17 • *Their recommendations are inconsistent with the facts of this proceeding.* The facts
18 demonstrate the North Dakota customers have benefited from our
19 investments in an integrated system. There is no basis for disallowing
20 these costs, as the costs of alternative supplies of energy required to serve
21 our North Dakota customers would be higher – likely substantially higher
22 – than our proposed rates.
- 23 • *They are not consistent with the statutory framework for ratemaking.* Ratemaking
24 provides for recovery of prudently incurred costs necessary for providing
25 service to customers. The recommendations of the Consultants are not
26 based on any showing that our costs were imprudent; in fact, their
27 testimony provides remarkably little factual support for such drastic

1 recommendations. Disallowance of prudently incurred costs that benefit
2 our customers is not an appropriate or constructive approach to addressing
3 concerns regarding the level of Commission involvement in our planning
4 process.

- 5 • *They will not be helpful in facilitating additional investment in North Dakota or*
6 *improving our service to customers.* Clearly, if we are unable to recover our costs
7 of providing service to North Dakota customers, we will be unable to
8 undertake new investments and system improvements that both enhance
9 customer service and address concerns about generating resources on our
10 system.
- 11 • *They would impair the financial viability of our North Dakota electric business*
12 *operations.* If earnings continue at recent levels or even deteriorate as a
13 result of this case, the financial viability of our North Dakota electric
14 business will be impaired. If significant investments were disallowed, the
15 long-term implications for earnings would be further damaged,
16 compounding the adverse financial effects.

17
18 We believe that all parties – the Company, our customers, the State of North
19 Dakota, and the region – have benefited from a long history of constructive
20 regulation. Our multi-state integrated system offers tremendous benefits and
21 cost savings for all of our customers; our ability to operate such a system
22 requires that all States allow us to meet the various requirements of the others.
23 While we appreciate the concerns that have been raised and are committed to
24 finding approaches to address them, I am convinced that adoption of the
25 recommendations would be:

- 26 • Harmful to the Company and our ability to provide service to our
27 customers.

- 1 • Harmful to our North Dakota customers, as our large, multi-state
- 2 integrated system would begin to dissolve, reducing benefits to all.
- 3 • Harmful to North Dakota’s overall interest in encouraging investments in
- 4 new generation and other system improvements.
- 5 • Harmful to the financial integrity of our North Dakota electric business.

6
7 Therefore, except as detailed within the Company’s Rebuttal Testimony, we
8 respectfully recommend that the Commission not adopt the recommendations
9 advanced by the Consultants in this proceeding.

10
11 Q. PLEASE DESCRIBE HOW YOU HAVE ORGANIZED THE REMAINDER OF YOUR
12 REBUTTAL TESTIMONY.

13 A. I present my Rebuttal Testimony in the following sections:

- 14 • *Benefits of an Integrated System.* In this section, I discuss how our long-
- 15 standing, constructive relationship with state regulators has allowed us to
- 16 operate a large, multi-state integrated system that provides tremendous
- 17 value to our customers. I offer evidence demonstrating how North
- 18 Dakota customers benefit from this system and the harm that stems from
- 19 potential fragmentation. The Rebuttal Testimony of Ms. Elizabeth
- 20 Engelking provides further support for these conclusions.
- 21 • *Overview of Key Investments.* Here, I present a high-level discussion of the
- 22 basis for the Company’s decision to invest in the projects recommended
- 23 for disallowance by Mr. King. Many of these investments are compliance-
- 24 driven and are needed to meet the requirements of our various
- 25 jurisdictions; others have been pursued as part of the Company’s overall
- 26 generation plan. In all cases, we believe that: (i) customers have benefited
- 27 and will benefit from these investments; (ii) our investments in these

1 projects were prudent; and (iii) our costs are appropriate for recovery. The
2 Rebuttal Testimony of both Ms. Engelking and Mr. Richard Rosvold
3 provide further support for this conclusion.

- 4 • *Impacts of the Consultants' Recommendations.* In this section, I provide our
5 assessment of the harm these recommendations would have on us as a
6 Company, our ability to continue to provide high-quality service to our
7 North Dakota customers, and our efforts to increase investment in new
8 facilities in North Dakota, and the financial viability of our business in
9 North Dakota. I present information on our current service levels, our
10 overall rates, our commitment to the communities we serve, and our plans
11 for future investment – each of which would be adversely affected by
12 adoption of the Consultants' recommendations.
- 13 • *Planning Proposal.* In response to the concerns regarding resource planning,
14 we have developed a proposal for consideration, as well as other initiatives
15 the Commission could consider. I present a high-level overview of these
16 recommendations, which will be further developed in the Rebuttal
17 Testimony of other Company witnesses.
- 18 • *Introduction of Witnesses.* In this section, I present the other Company
19 witnesses sponsoring Rebuttal Testimony and an overview of the
20 information they provide.
- 21 • *Summary and Conclusions.* Finally, I summarize the importance of this case to
22 the Company, our position on the key issues in dispute, and our
23 recommendations to the Commission.

24
25
26
27

1 **III. BENEFITS OF AN INTEGRATED SYSTEM**

2
3 Q. PLEASE DESCRIBE WHAT YOU MEAN BY THE TERM “INTEGRATED SYSTEM.”

4 A. By “integrated system,” I mean the operation of our entire, multi-state system
5 of generating, transmitting, and delivering electricity services within both the
6 NSP-Minnesota and the NSP-Wisconsin operating companies of Xcel Energy
7 Inc. (the “NSP System”). The NSP System encompasses five states in the
8 upper Midwest, including Minnesota, Michigan, North Dakota, South Dakota,
9 and Wisconsin. While the Company’s assets needed to provide service to our
10 customers in these states are not all directly connected, they are all connected
11 as a larger, interconnected network of assets owned by other public utilities,
12 cooperatives, and municipal utilities.

13
14 Connection with this larger, regional network of assets allows us to plan and
15 operate our entire five-state system on an integrated basis. That means, for
16 example, that we can plan our fleet of generating plants on a total-system
17 basis, as opposed to attempting to plan on a state-by-state or community-by-
18 community basis.

19
20 Q. WHAT ADVANTAGES DOES AN INTEGRATED SYSTEM OFFER?

21 A. A large, integrated system allows us to:

- 22 • Reduce the total amount of generating resources used to serve customers;
23 • Diversify the fleet of generating resources required to meet our customers’
24 needs, lowering costs and risks; and
25 • Lower costs by spreading costs over a substantially larger and diverse
26 customer base.

27

1 Q. PLEASE EXPLAIN HOW AN INTEGRATED SYSTEM REDUCES THE TOTAL NEED
2 FOR GENERATING RESOURCES.

3 A. A large, integrated system such as ours requires fewer total generating
4 resources compared to several, smaller systems serving a similar number of
5 customers. This result arises from our ability to take advantage of load
6 diversity across a large number of customers and broad geographic area. For
7 example, a system that combines the usage of relatively peak-sensitive, low
8 load-factor customers with the usage of large, industrial customers with
9 significant off-peak usage will require a lower total amount of generating
10 capacity as compared to two separate systems serving each group. Generally
11 speaking, the larger and broader the range of customers, the greater the
12 diversity of their energy load and usage characteristics will be; and the greater
13 the diversity of load, a greater advantage for generation planning is created.

14

15 Q. PLEASE ELABORATE ON YOUR SECOND POINT REGARDING DIVERSITY OF
16 GENERATING RESOURCES.

17 A. A 10,000 MW system such as ours provides the breadth and scope to support
18 a variety of generating resources that could not otherwise be justified in a
19 smaller system. As indicated in Figure 1 below, our generating fleet is among
20 the most diverse in the nation. Power is generated by nuclear, coal, hydro,
21 natural gas, oil, wind, and biomass -- even garbage.

22

23

24

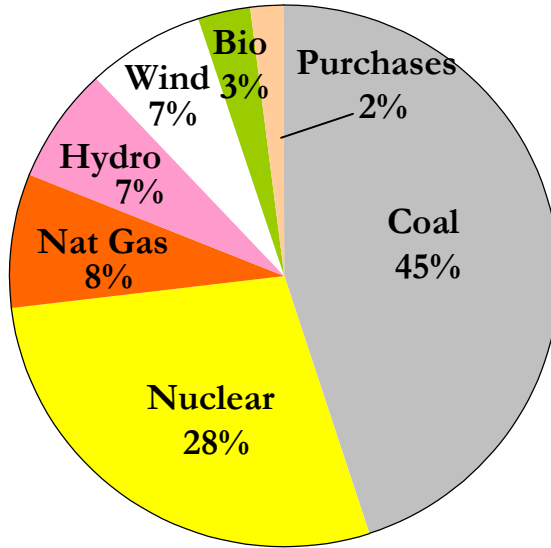
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1 **Figure 1: Xcel Energy's Portfolio of Resources**

2
3 (% of MWH Produced)



15
16 Such a diverse fuel mix allows us to not only reduce costs for customers, but
17 also to diversify risk:

- 18
- 19 • Costs are lower, as we have sufficient scale to justify investments in base
20 load nuclear and coal plants that reduce average costs to all customers; and
 - 21 • Risks are lower because we are not dependent on any one fuel source.

22 In times of significant fuel price volatility, as we are currently experiencing, a
23 diversified fuel mix provides a tremendous price hedge for our customers as
24 compared to an electric system dependent on only one or two fuel sources.

25 I should note also that in 2007, 606,500 MWHs of electricity used to serve
26 Xcel Energy's customers in North Dakota was produced by generating
27 facilities located in North Dakota; this represents roughly 25 percent of our
28 North Dakota retail sales.

1 Q. CAN YOU EXPLAIN YOUR THIRD POINT REGARDING REDUCED COSTS DUE TO A
2 LARGER CUSTOMER BASE?

3 A. Yes. Operating an electric system requires certain basic infrastructure
4 investments and services to simply run the business. Because such business
5 costs can be spread over a larger customer base, the average cost of providing
6 service is lower.

7

8 Q. DO YOU BELIEVE XCEL ENERGY'S INTEGRATED SYSTEM HAS PROVIDED
9 BENEFITS SUCH AS THOSE YOU DESCRIBE TO NORTH DAKOTA CUSTOMERS?

10 A. Definitely, yes. For example, in 2007, the average cost of generation on our
11 system averaged \$45.00/MWH. In comparison, average market prices were
12 \$55.00/MWH. Adding the consideration of fixed or capacity costs, our
13 system average was \$77.00/MWH as compared to \$89.00/MWH for the
14 market. Likewise, the average all-in costs of nuclear generation on our system
15 was \$36.66/MWH, significantly lowering our average costs. Utilities of
16 smaller scale would be unable to justify or support investment in such a large-
17 scale, capital-intensive generating resource as a nuclear unit; our system
18 includes three nuclear units, providing over 1500 MWs of generating capacity.
19 Ms. Engelking's Rebuttal Testimony provides further support for these
20 benefits. But I believe there can be no question that our five-state, integrated
21 system offers tremendous benefits to our customers.

22

23 Q. ARE THERE ANY PARTICULAR ADVANTAGES TO NORTH DAKOTA CUSTOMERS
24 DUE TO XCEL ENERGY'S INTEGRATED SYSTEM?

25 A. Yes. The smaller jurisdictions of our five-state service territory enjoy the
26 greatest benefits from being part of a larger system. Our North Dakota load
27 accounts for approximately 500 MW of a 10,000 MW system, or

1 approximately five percent. To meet the needs of this size load on a stand-
2 alone basis, we would likely need to rely on either natural gas generation or a
3 smaller coal plant supplemented with purchased power – there would certainly
4 be no way to support the broad, diverse portfolio of resources currently
5 serving our system. The cost and risk advantages of the integrated system are
6 very apparent, with natural gas costs currently at about \$11/MCF and
7 purchase power costs averaging around \$85/MWH to \$125/MWH or more in
8 peak summer periods.

9
10 Q. ARE THERE ANY DRAWBACKS TO A LARGE, INTEGRATED SYSTEM?

11 A. I do not know that I would call it a “drawback,” but a multi-state, integrated
12 system clearly does require the support of all jurisdictions in which it operates.

13
14 Q. PLEASE ELABORATE.

15 A. We need to meet the applicable requirements of each state and community in
16 which we serve and in which our facilities are located; perhaps particularly
17 since we are a public utility, compliance with all requirements is essential to
18 our ability to do business in a particular state. An integrated system inherently
19 recognizes and respects this need, as it allows the costs of meeting these
20 requirements and operating these facilities to be proportionately shared across
21 the entire system.

22
23 Q. WHY WOULD REGULATORS IN ONE JURISDICTION ALLOW FOR THE RECOVERY
24 OF A SHARE OF COSTS REQUIRED BY THE LAWS AND REGULATIONS OF
25 ANOTHER JURISDICTION?

1 A. Regulators allow the sharing of such costs because they are small compared to
2 the benefits, including cost savings, provided by the larger scale of an
3 integrated system.

4
5 Q. PLEASE CONTINUE.

6 A. The Direct Testimony of Mr. King challenges this fundamental premise of an
7 integrated system: instead of recommending acceptance of a proportionate
8 share of our total system costs, Mr. King recommends significant
9 disallowances, including the costs of meeting Minnesota requirements that
10 apply to generation facilities located in Minnesota. At least part of the basis of
11 this recommendation is disagreement that North Dakota customers should
12 pay any share of the costs of meeting certain statutory requirements of other
13 jurisdictions. The problem with this approach, however, is that once we begin
14 to disaggregate total system costs in any way other than proportionately across
15 our entire system, we will quickly lose the very nature and benefits of an
16 integrated system.

17
18 Q. WHY IS THAT?

19 A. Once such disaggregation of costs begins, there is little impetus to stop and
20 few logical distinctions to support stopping part way. For example, the
21 Minnesota Legislature adopted certain requirements as a precondition to our
22 ability to add spent-fuel storage at our nuclear facilities. If, for example, the
23 Commission denied us recovery of a proportionate share of those costs
24 (believing, as Mr. King argues, that those costs are instead appropriately
25 assigned to Minnesota customers), there is little reason for Minnesota to not
26 claim that it is exclusively entitled to the benefits of low-cost nuclear

1 generation, since it is host to the nuclear plants, and the costs of keeping the
2 plant operating would be borne by Minnesota customers.

3
4 Thus, this is quite frankly a case where the system either hangs together as a
5 whole, or falls apart into separate, jurisdictional systems:

- 6 • Unless each jurisdiction accepts a proportionate share of our total costs of
7 providing integrated service, there is little likelihood that all of the
8 jurisdictions will agree on a different means of allocating costs among
9 them;
- 10 • But unless the utility can recover all of its costs across the jurisdictions
11 through the support of each of the jurisdictions, it cannot continue to
12 operate as an integrated system. Once we embark on such disaggregation,
13 the benefits that come from large scale and scope will dissolve.

14
15 Q. WHY DO YOU SAY THAT THE UTILITY WILL NOT BE ABLE TO CONTINUE TO
16 OPERATE AS AN INTEGRATED SYSTEM IF IT CANNOT RECOVER ALL OF ITS COSTS
17 OF PROVIDING SERVICE IN NORTH DAKOTA?

18 A. Like any business, a utility needs to recover all of its costs to remain viable and
19 continue to fund the needed new investments and improvements to supply its
20 customers' growing needs. While there certainly are advantages to operating
21 in a number of jurisdictions, there is also a key risk – that being the risk that
22 jurisdictions will change the approach to cost sharing in any one given rate
23 proceeding. Because these issues will surface in individual rate proceedings
24 before the various state utility commissions at different times, the utility will
25 not have any means to recapture the disallowed cost until the next rate
26 proceeding in the other jurisdictions. As discussed above, once the premise of
27 proportionate cost sharing is challenged, it is likely that the other jurisdictions

1 will seek to implement their own alternative cost-sharing approaches. In my
2 view, there is no way the integrated system can remain whole in this situation,
3 and the ability to continue to maintain that system will be lost.
4

5 Q. WHAT ALTERNATIVE APPROACH IS AVAILABLE TO A JURISDICTION CONCERNED
6 ABOUT THE COSTS IMPOSED BY ANOTHER JURISDICTION?

7 A. I believe the best way is to continue to employ the constructive regulatory
8 approach that has traditionally been used across our service territories to
9 address these types of concerns. We have worked through complex challenges
10 in the past and can do so again now; this approach has served all parties – our
11 customers, the Company, the states we serve, and the region – well.
12

13 In this case, since much of the concern is focused on our generation
14 investments, a more cooperative effort on resource planning – both between
15 Xcel Energy and the Commission, and among the various state utility
16 commissions of our service territory – would appear to offer a step in that
17 direction. To this end, we make several proposals in our Rebuttal Testimony
18 that would facilitate this effort. I urge the Commission to employ such
19 constructive means of addressing its concerns, as opposed to adopting
20 recommendations for drastic cost disallowances. I believe North Dakota
21 customers and the State of North Dakota will benefit from such an approach,
22 both now and in the long term.
23
24

1 **IV. OVERVIEW OF KEY INVESTMENTS**

2
3 Q. CAN YOU IDENTIFY THE KEY INVESTMENTS RECOMMENDED FOR
4 DISALLOWANCE?

5 A. Yes. Disallowance of costs associated with the following key projects on our
6 system has been recommended:

- 7 • *King Plant*, our rehabilitation project at a 564 MW coal plant. This project
8 allows us to extend the life of this important, low-cost resource for our
9 system by at least 25 years, reclaim 60 MW of lost net dependable capacity
10 due to degradation, and install state-of-the art pollution control equipment
11 that is now essential to meeting our requirements under federal law. Mr.
12 King suggests that we undertook this project earlier than necessary, and
13 concludes that the costs of this project should be disallowed.
- 14 • *High Bridge Plant*, our replacement of 243 MW coal plant with a modern
15 and efficient natural gas combined-cycle plant. This project allowed us to
16 address the issues of an end-of-life coal plant located on the Mississippi
17 River in the heart of a central city, expand net dependable capacity by 272
18 MW, and take advantage of existing transmission capacity at a time when
19 the transmission system is operating at near-full capacity. Given the
20 Company's need for intermediate-load and peak generation, a natural gas
21 combined-cycle plant presents the most cost-effective and dispatchable
22 resource for this type of need. Mr. King states that we should have
23 pursued a coal-based option instead, and imputes a \$3.8 million cost
24 disallowance based on previous estimates of the costs of such an option.
- 25 • *Mercury control projects at our King and Sherco coal-fired plants*, our projects to
26 meet the requirements of MMRA. These projects are compliance-driven
27 and necessary to ensure we meet the requirements of applicable law;

1 however, we also believe that making these investments now in advance of
2 any possible Federal mandate will benefit our customers, as compliance
3 costs increase substantially once national mandates are imposed. Mr. King
4 asserts that such compliance costs that are beyond the requirements of
5 Federal law should be paid for by Minnesota and recommends a \$438,000
6 disallowance.

7 • *Grand Meadow wind project and the southeast Minnesota transmission project,*
8 projects that supply needed energy for our system and help us comply with
9 renewable requirements of our various jurisdictions. Mr. King
10 recommended disallowance of 25 percent of these costs (amounting to
11 \$79,000) based on a belief that North Dakota wind would have been more
12 cost-effective.

13 • *The Red Wing and Wilmarth refuse-derived fuel plants,* which provide a combined
14 40 MW of capacity to our system. These facilities have been in operation
15 for nearly 25 years and have provided both reliable, reasonably-priced
16 service while addressing solid-waste management issues. Mr. King
17 recommends disallowance of \$173,000 in costs of these plants, because
18 they help us meet the Minnesota Renewable Energy Standard, arguing such
19 costs should be recovered exclusively from Minnesota customers.

20
21 Q. WHAT IS YOUR REACTION TO THESE RECOMMENDED DISALLOWANCES?

22 A. As I indicated earlier, I believe the breadth and scope of these recommended
23 disallowances are a drastic and disproportionate remedy to the concerns
24 raised. More specifically, I have four key concerns regarding these
25 recommendations:

26 • *There is little to no factual support for the recommendations.* For example, with
27 respect to the Allan King Plant, there is no support for the conclusion that

1 we undertook the rehabilitation too early. A complex rehabilitation project
2 such as our King Plant project takes considerable time and planning – it
3 would not have served our customers well to delay that project. As
4 discussed in greater detail in Ms. Engelking’s Rebuttal Testimony, that
5 plant was reaching the end of its useful life, experiencing the typical issues
6 of reduced performance due to aging — it was about 35 years old years old
7 when we proposed the MERP project. The simple statement that we could
8 have waited to rehabilitate clearly does not provide adequate justification
9 for a \$3.4 million cost disallowance of a project that provides significant
10 cost benefits our customers.

- 11 • *They reflect a reactive, rather than proactive, view of how we should plan our investments.*
12 For example, Mr. King indicates that we should wait until required by the
13 Federal government to undertake investments in pollution-control
14 equipment. I do not believe that approach serves our customers well.
15 Indeed, as discussed in Mr. Rosvold’s Rebuttal Testimony, our efforts to
16 anticipate certain requirements have greatly benefited our customers, in
17 that we do not face the higher costs of implementing compliance projects
18 at the same time as all other utilities. In my view, the issues before the
19 Commission require far more thoughtful and measured consideration than
20 the simple rejection of our carefully considered strategy.
- 21 • *They assume we had options that did not exist.* For example, with respect to the
22 High Bridge plant, Mr. King’s recommendation assumes that a coal-based
23 option was a realistic option and should have been pursued instead of our
24 repowering project. However, coal rehabilitation was not a viable option at
25 that site – like the experience of other utilities across the country, air-
26 quality and other environmental permits needed for continued coal
27 operations were not viable or going to be easily obtained for a site located

1 on the Mississippi River near downtown St. Paul, Minnesota. While Ms.
2 Engelking and Mr. Rosvold provide further support on this issue, I believe
3 our High Bridge project offered by far the best option for our customers in
4 that it: (i) maintains a critical generation site on our system; (ii) takes
5 advantage of existing transmission capacity when most of the rest of the
6 system is at maximum capacity; (iii) provides 272 MW of additional
7 capacity needed for our customers; and (iv) offers operational advantages
8 as our load and system changes.

- 9 • *They are not properly calculated and are difficult to reconcile to our actual costs and*
10 *financial statements.* For example, the recommendation to disallow 25
11 percent of our Grand Meadow and transmission projects fails to account
12 for the additional transmission costs that would be required to implement
13 the North Dakota wind used as a basis for the recommended disallowance.
14 Likewise, the recommended disallowance of High Bridge costs is based on
15 estimated costs of simply additional pollution control equipment, not the
16 costs of rehabilitating and extending the life of the prior coal plant or the
17 replacement costs of the 272 MW of additional capacity our project
18 provides. Even if one accepts the premise behind Mr. King's
19 recommendation, the recommended levels of disallowance are not accurate
20 and are not based on an adequate factual record. The Rebuttal
21 Testimonies of Ms. Anne Heuer and Ms. Engelking provide additional
22 detail on this point.

23
24 As it always has, the Commission must consider our rate request in light of the
25 applicable laws and facts of the case. As we present in detail in our Rebuttal
26 Testimony, our requested costs are prudently incurred and necessary to
27 providing high quality, reliable electric service to our North Dakota customers.

1 While we respect the concerns expressed in this case, a far greater showing
2 than concern is required to support the drastic recommended cost
3 disallowances. We believe the Commission has available more constructive
4 approaches to these issues that should be adopted in this case.

5
6 **V. IMPACT OF STAFF CONSULTANTS' RECOMMENDATIONS**

7
8 Q. YOU HAVE INDICATED THAT XCEL ENERGY'S NORTH DAKOTA CUSTOMERS
9 CURRENTLY ENJOY QUALITY SERVICE AT REASONABLE PRICES. CAN YOU
10 ELABORATE?

11 A. Yes. Our North Dakota customers enjoy very high-quality, reliable electric
12 service at reasonable rates:

- 13 • Our customer surveys indicate a high level of satisfaction, with 96 percent
14 indicating positive views of our service.
- 15 • Our rates are among the lowest in the region, ranking first in 2007 against
16 29 other Midwest utilities.
- 17 • Our reliability in North Dakota is exemplary and among the best of all
18 Xcel Energy jurisdictions, with a system average interruption duration
19 index ("SAIDI") of under 70 minutes. In fact, the Company met or
20 exceeded the Commission-approved reliability performance standards nine
21 out of ten times during the 2001-2005 term of performance-based
22 regulation in North Dakota.

23
24 In addition, Xcel Energy has been a good corporate citizen, making valuable
25 contributions both financially and through our active, engaged employees who
26 make a difference in the communities we serve. For example, we have
27 provided:

- 1 • \$4.7 million in funding to the University of North Dakota (“UND”) for
2 energy and environmental projects;
- 3 • \$300,000 toward the development of the North Dakota State University
4 (“NDSU”) and UND technical parks;
- 5 • In 2007, just under \$90,000 toward on-going state and local economic
6 development efforts;
- 7 • In 2007, over \$220,000 in charitable contributions toward non-profit
8 entities, including \$28,000 to the United Way; and
- 9 • Annual contributions of \$20,000 to Energy Share.

10 We are also proud to have Xcel Energy recognized in 2007 as a national leader
11 in our support for our communities with the United Way’s Spirit of America
12 award.

13
14 Q. WHAT PLANS DO YOU HAVE FOR FUTURE FOR INVESTMENT IN NORTH
15 DAKOTA?

16 A. We plan to continue to build on our investments in wind systems, building
17 diversity in our current portfolio of purchased power contracts for renewable
18 resources. We are in the process of evaluating bid proposals for 500 MW of
19 wind resources, and several North Dakota projects are currently under
20 consideration. Given the tremendous potential for wind in North Dakota, we
21 fully expect to own wind assets in North Dakota, as we work to meet
22 renewable energy requirements.

23
24 Unlocking the potential of wind development in North Dakota requires that
25 we address the constrained transmission system, so we can move the resource
26 to major load centers, including those located outside of North Dakota. For
27 example, we are seeking approval to build a 345-kV line extending from Fargo

1 to the Twin Cities as part of the CapX 2020 project, a project that will provide
2 substantial relief to that congestion. The Minnesota Office of Energy Security
3 recently recommended that we increase the size of that line to accommodate
4 even more transfer capability from the west and north. We support that policy
5 recommendation and are proposing to build facilities that can readily be
6 double circuited (i.e., support two 345-kV lines), so that the transmission
7 corridor can be effectively doubled in a comparative short period of time as
8 future circumstances warrant.

9
10 We typically invest more than \$3 million each year to maintain, upgrade, and
11 expand our distribution system. We are currently exploring the potential for
12 automating portions of our North Dakota distribution system to dramatically
13 improve system reliability by reducing the time needed to restore power during
14 an outage. With this technology, state-of-the art switches would automatically
15 isolate the affected mainline feeders in an outage event and restore power to a
16 majority of the impacted customers within minutes.

17
18 Q. WHAT IMPACT WOULD ADOPTION OF THE CONSULTANTS'
19 RECOMMENDATIONS HAVE ON THESE PLANS?

20 A. There is no question that adoption of their recommendation to reduce our
21 current rates would have a significant negative impact on these efforts. We
22 need to be a financially strong, viable company to continue to expand and
23 make substantial investments such as those I have noted. Our actual and
24 normalized returns are not sufficient to maintain that financial viability of our
25 North Dakota electric business operations; reducing rates from current levels
26 would further exacerbate this situation.

27

1 **NORTH DAKOTA EARNED RETURN**

2

	<u>2006</u>	<u>2007</u>
3 Actual Return	8.52%	3.41%
4 Normalized Return	8.85%	2.96%

5

6

7 Adoption of the Consultants’ recommendations would extend this pattern of
8 inadequate earnings. As explained in the Ms. Heuer’s Rebuttal Testimony, we
9 estimate that our 2008 return on equity would be approximately 4.3 percent,
10 were the Commission to adopt the their recommendations. Further, since a
11 substantial portion of the cost disallowances would be based on disallowed
12 investments, the adverse effects would last for many years in the absence of a
13 reversal of position in a later case. Ms. Heuer’s Rebuttal Testimony indicates
14 that the disallowance of investments would decrease earnings from our North
15 Dakota electric operations that are available for shareholders by over 20
16 percent, and that the effect would last for many years. This combination of
17 financial consequences would undermine the financial viability of our North
18 Dakota electric business operation.

19

20 Q. WHAT DO YOU CONCLUDE FROM THIS POTENTIAL RESULT?

21 A. I believe that this result would be contrary to the interests of our customers
22 and communities, the State, and our Company. For example:

- 23
- 24 • It would impede our ability to continue to provide the high quality of
25 service our North Dakota customers currently enjoy as a result of being
26 part of an integrated system.
 - It would harm our ability to expand our investments in North Dakota.

1 • It would seriously impair the overall financial viability of our North Dakota
2 electric business by denying us recovery of our prudent and reasonable
3 costs of providing service.

4 • It would harm our ability to support state and local economic development
5 initiatives in North Dakota.

6 Overall, I do not believe this is the path the Commission should take. Instead,
7 the Commission should consider alternative, more constructive approaches to
8 addressing issues and concerns.

9 10 **VI. PLANNING PROPOSAL**

11
12 Q. HOW DOES XCEL ENERGY DEVELOP ITS RESOURCE PLANS?

13 A. Xcel Energy develops its resource plans on the basis of the integrated NSP
14 System that serves customers of both the NSP-Minnesota and the NSP-
15 Wisconsin operating companies. To do this, we examine the capacity and
16 energy needs and the regulatory and legal requirements in each of our
17 jurisdictions and design a plan that meets all of those requirements at the
18 lowest possible cost.

19
20 Q. WHAT ARE THE BENEFITS OF THIS PLANNING METHODOLOGY?

21 A. Planning on the basis of an integrated system allows us to take advantage of
22 economies of scale as well as the diversity of customer needs to provide lower
23 costs to all of our customers. For example, we are able to construct larger and
24 more economical facilities such as our nuclear plants and our 2,400 MW
25 Sherco coal-fired generating facility. We are also able to maintain one of the
26 most diverse fuel mixes of any utility in the country, utilizing coal, nuclear,
27 hydro, natural gas, wind, biomass, and oil to serve our customers' energy

1 needs. In addition, we are able to coordinate the requirements of our various
2 jurisdictions and develop a plan that meets all of them at the lowest possible
3 cost.

4
5 Q. WOULD NORTH DAKOTA CUSTOMERS BENEFIT FROM A PLAN THAT PROVIDES
6 DIFFERENT RESOURCE REQUIREMENTS FOR DIFFERENT JURISDICTIONS?

7 A. No. If we were required to file a North Dakota-specific resource plan, we
8 would no longer be able to plan on an integrated basis. Instead, we would
9 need to propose specific resources to meet North Dakota needs and policies
10 that would not necessarily comply with the requirements of our other
11 jurisdictions. This could result in a number of conflicts for the Company and
12 higher overall costs for all of our customers. For example, if the Commission
13 were to determine that our North Dakota resource plan should not include
14 wind energy in excess of its own objectives, we would need to include energy
15 from other resources to make up for the wind energy that would no longer be
16 going to North Dakota customers. This would either involve construction of
17 smaller, more costly exclusive resources to meet North Dakota needs or, more
18 likely, result in market purchases that would need to be paid for by North
19 Dakota customers. As noted above, the cost of our wind resources is
20 currently far below the market price, so such a decision would necessarily raise
21 costs to North Dakota consumers.

22
23 Similarly, if the Commission were to determine that constructing a coal plant
24 would be the most prudent action for North Dakota customers, it would not
25 be possible for Xcel Energy to comply unless it also got agreement from its
26 other jurisdictions. Our North Dakota load is simply not large enough to
27 support the construction of such a large generating facility. And if we were to

1 construct facilities to meet only North Dakota goals and requirements, our
2 North Dakota customers would lose out on the benefits of diversity of load
3 and resources that help keep costs low for all of our customers.
4

5 Q. WHAT CAN XCEL ENERGY DO TO IMPROVE HOW ITS RESOURCE PLANNING
6 PROCESS CONSIDERS JURISDICTIONAL REQUIREMENTS AND PREFERENCES?

7 A. Xcel Energy recognizes that the Commission desires greater participation in
8 our planning process. In order to maximize the benefits of an integrated
9 system, we believe that input from the Commission is of most value during
10 the period that we are developing our resource plan.
11

12 To that end, I would like to propose a multi-jurisdictional and collaborative
13 planning process that would take place approximately three months prior
14 to the completion of our resource plan. Through this process, we
15 would invite Commissions and their staffs in all of our NSP System
16 jurisdictions to come together and share the goals and requirements that
17 would need to be considered in the development of Xcel Energy's resource
18 plan. These joint meetings would provide opportunities for regulators from
19 each jurisdiction to discuss specific concerns and conflicts between various
20 goals and requirements. We would expect this process to be iterative; as Xcel
21 Energy uses the information from these meetings to help develop its plan, we
22 would share developments with our regulators for additional feedback.
23

24 While the specifics of such a process still need to be determined, we believe
25 that a more collaborative process will help us create a single, integrated long-
26 term resource plan that brings benefits to all of our jurisdictions and also
27 address the specific concerns of the Commission.

1

2 Q. HOW CAN XCEL ENERGY MODIFY ITS PLANNING TO ADDRESS THE
3 COMMISSION'S CONCERNS ABOUT THE LOCATION OF COMPANY GENERATING
4 FACILITIES?

5 A. Since the 1990s, the former Northern States Power Company and later Xcel
6 Energy have procured its resources through competitive processes. These
7 processes have focused on finding the lowest cost resources for our
8 customers, regardless of their location.

9

10 We understand that all of our jurisdictions are interested in the benefits that
11 come from locating generating facilities in their states. While we cannot
12 commit to placing facilities in particular jurisdictions, we can consider
13 modifying our planning criteria to provide added emphasis to location
14 preferences in considering and selecting resources. We would welcome
15 Commission input into this concept and would be willing to work with North
16 Dakota and the other jurisdictions to arrive at a workable model.

17

18 Q. HOW DOES THIS PROPOSAL ADDRESS THE COMMISSION'S CONCERNS
19 REGARDING THE PRIORITIES OF NORTH DAKOTA IN PLANNING FOR FUTURE
20 ENERGY NEEDS?

21 A. A collaborative approach involving energy policymakers from all affected
22 jurisdictions provides a forum for regulators to discuss the energy priorities in
23 each state and work toward "win-win" policies that address the interests of all
24 jurisdictions served by the Company. In an essay published by the Council of
25 State Governments in 2007, Commissioner Tony Clark stated, "...the best way
26 to avoid these problems is to foster regional discussions and education about
27 the interdependency we all have on our regional electricity grids." He goes on

1 to say that only by coordination across state lines can we ensure that all
2 consumers, economies, and the environment are well served for generations to
3 come. I believe our proposal to facilitate direct discussions among regulators
4 during the resource planning cycle mirrors the type of effort Commissioner
5 Clark calls for.

7 VII. INTRODUCTION OF REBUTTAL WITNESSES

8
9 Q. PLEASE INTRODUCE THE OTHER REBUTTAL WITNESSES XCEL ENERGY IS
10 SPONSORING IN THIS PROCEEDING.

11 A. In addition to me, the Company is sponsoring Rebuttal Testimony from the
12 following witnesses:

- 13 • *Ms. Elizabeth M. Engelking*, who presents factual support for our key
14 system investments and describes in further detail our planning proposal
15 for the Commission's consideration.
- 16 • *Mr. Richard A. Rosvold*, who presents information regarding our
17 environmental requirements and plans, applicable state and federal laws,
18 and further factual support for the customer benefits of our approach to
19 environmental improvements.
- 20 • *Mr. Dane A. Watson* of Alliance Consulting Group, who provides our
21 assessment of the recommendation regarding non-legal asset retirement
22 obligations and our rationale as to why it should not be adopted.
- 23 • *Mr. Jeffrey C. Robinson*, who provides support for our depreciation costs
24 and methods of determining the remaining lives of our assets.
- 25 • *Mr. Allen D. Krug*, who provides support for our proposal regarding
26 wholesale margins.

- 1 • *Ms. Anne E. Heuer*, who provides support for our requested recovery of
2 certain costs recommended for disallowance, our assessment of the
3 financial impact of the recommendations by the Consultants, and our
4 recommended overall financial request, reflecting the overall position of
5 the Company in this proceeding.
- 6 • *Mr. Phillip J. Zins*, who provides further clarification regarding our
7 interruptible rate programs and the impact of our decision to join the
8 Midwest Independent System Operator planning reserve group.

9
10 Together, these witnesses provide the Company's response to the Direct
11 Testimony of the Consultants.

12 13 **VIII. SUMMARY AND CONCLUSIONS**

14
15 Q. PLEASE SUMMARIZE YOUR CONCLUSIONS FOR THE COMMISSION.

16 A. This electric rate case is extremely important for our customers, the Company,
17 and the State of North Dakota. Our customers enjoy high-quality, reliable
18 service at reasonable rates, and benefit from our high level of community
19 involvement. We have a long tradition of constructive relationships with our
20 customers, communities and regulators.

21
22 We are committed to continuing these constructive relationships and
23 expanding our investments in North Dakota. We also recognize the concerns
24 regarding the balance of costs and requirements among the jurisdictions we
25 serve. We will work to address these concerns, and offer a proposal for
26 cooperative planning to that end.

27

1 Our ability to maintain our commitments requires that we remain financially
2 viable and strong. Our North Dakota customers have benefited greatly from
3 our integrated system; retaining those benefits depends on each jurisdiction's
4 willingness to accept a proportionate share of the associated costs, allowing us
5 to recover our prudent costs of serving customers.

6
7 As such, we respectfully recommend that the Commission not adopt the
8 recommendations contained in the Direct Testimony of the Consultants, and
9 instead adopt the Company's position, as articulated in this Rebuttal
10 Testimony. This position includes:

- 11 • Adoption of the 10.75 percent return on equity and 8.8 percent overall rate
12 of return, as provided in the Stipulation Agreement dated January 10,
13 2008.
- 14 • Approval of an overall rate increase of 12.15 percent allowing us to
15 recover the \$17.946 million revenue deficiency reflected in the Rebuttal
16 Schedules of Ms. Heuer.
- 17 • Adoption of our proposals relating to an expanded Resource Planning
18 process, and continued Commission involvement in the current process of
19 establishing depreciation lives and rates so as to not necessitate the formal
20 filing of a stand-alone depreciation study with the Commission.

21
22 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

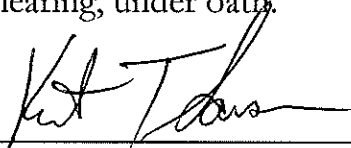
23 A. Yes, it does.

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

5
6 In the Matter of the Application of Northern)
7 States Power Company, a Minnesota Corporation)
8 For Authority to Increase Rates for Electric Service) Case No. PU-07-776
9 in North Dakota)

10
11
12
13 AFFIDAVIT OF
14 Kent T. Larson
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 Kent T. Larson
26

27
28
29
30 Subscribed and sworn to before me, this 12 day of June, 2008.

31
32 
33 _____
34 Notary Public
35
36



Rebuttal Testimony and Schedule
Jeffrey C. Robinson

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Northern States Power Company,
a Minnesota corporation and wholly owned subsidiary of Xcel Energy Inc.

For Authority to Increase Rates for
Electric Service in North Dakota

Case No. PU-07-776
Exhibit ____

**Depreciation
Methodologies, Life Extensions,
Separate Study**

June 13, 2008

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1 **I. INTRODUCTION AND QUALIFICATIONS**

2
3 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

4 A. My name is Jeffrey C. Robinson. My business address is 1270 Kolff Court,
5 Newport, Minnesota 55055.

6
7 Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

8 A. Since my retirement from Xcel Energy Services Inc. (“XES” or the “Service
9 Company”) as Manager of Revenue Analysis at the end of 2006, I have been
10 providing support to the Regulatory area of XES on a part-time contract
11 basis. My resume is included as Exhibit___(JCR-2), Schedule 1.

12
13 Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

14 A. I have over thirty-four years of employment experience with Northern States
15 Power Company, a Minnesota corporation (“Xcel Energy” or the
16 “Company”). I have an extensive background in matters that concern the
17 capital invested in utility property and depreciation. I have held management
18 positions in the areas of Depreciation Services, Depreciation & Nuclear Fuel
19 Accounting, Corporate Economics & Depreciation, and Capital Asset
20 Accounting. From 1994 until my retirement at the end of 2006, I was the
21 manager of Revenue Analysis. Since my retirement I have continued to
22 support the rate regulatory process on a part-time contract basis. This has
23 included overall revenue requirements testimony and work on a variety of
24 regulatory petitions related to cost recovery and accounting.

25
26 Q. FOR WHOM ARE YOU TESTIFYING?

1 A. I am testifying on behalf of Northern States Power Company (“Xcel Energy”
2 or the “Company”), a Minnesota corporation operating in North Dakota.

3

4 Q. HAVE YOU FILED TESTIMONY PREVIOUSLY IN THIS PROCEEDING?

5 A. No.

6

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

8 A. The purpose of my Rebuttal Testimony is to respond to statements made by
9 Mr. Charles King in his Direct Testimony related to Xcel Energy’s
10 depreciation study. More specifically, I will address Mr. King’s proposals
11 related to depreciation methodologies, life extensions and the development of
12 a North Dakota specific depreciation study. Mr. Dane Watson will respond
13 on behalf of the Company to Mr. King’s proposal related to determining
14 retirement costs and Mr. Mojos’ proposal for refunding amounts paid by
15 past ratepayers toward future retirement costs.

16

17 Q. WAS THE SCHEDULE PRESENTED WITH YOUR TESTIMONY PREPARED BY YOU
18 OR UNDER YOUR SUPERVISION?

19 A. Yes, it was.

20

21 **II. SUMMARY AND ORGANIZATION**

22

23 Q. PLEASE PROVIDE A SUMMARY OF YOUR REBUTTAL TESTIMONY.

24 A. After reviewing the Direct Testimony filed in this docket regarding the
25 Company’s depreciation study, retirement practices and the resulting
26 depreciation rates, the Company stands behind its proposed depreciation
27 rates. To summarize where the issues are that I will address, the main

1 difference between the Company's recommendations and Mr. King's
2 recommendations are the choice of the depreciable lives related to certain
3 generating facilities and distribution plant accounts. I will explain why the
4 Company's current depreciation rates are reasonable and why the Commission
5 should continue to treat depreciation on a total-system basis.

7 III. DEPRECIATION METHOD

8
9 Q. PLEASE DESCRIBE THE METHODS THE COMPANY USES FOR ESTABLISHING
10 DEPRECIABLE LIFE AND WHY THESE METHODS ARE APPROPRIATE.

11 A. For Production assets, Xcel Energy uses a straight-line life span method to
12 calculate depreciation rates. In the life span method, the retirement date of
13 each generating unit is determined based on the facts and circumstances
14 surrounding each generating unit. The sum of the net investment (original
15 cost less accrued reserve) and the net salvage cost of each generating unit is
16 divided by the remaining years until the retirement date to determine the
17 depreciation expense required each year in order to fully depreciate the unit
18 and ensure sufficient expense is accrued for the net salvage of the unit. This
19 is the standard method used across the industry to model depreciation
20 expense for production facilities.

21
22 For transmission plant, distribution plant and general structure plant
23 accounts, Xcel Energy uses the straight-line average life procedure to calculate
24 depreciation rates. For these accounts, a whole-life calculation is made where
25 the investment is allocated over the full life of the assets. This method uses a
26 constant annual accrual rate based on the average life of all property in the
27 group, which rate is applied to the surviving property. Because the accrual

1 rate is based on the average life of the group, the difference between accruals
2 for early retirements will be balanced during the life of those properties
3 having lives longer than the average. The result is that differences in actual
4 experience are largely offset and the group as a whole will be fully depreciated
5 by the time of the final retirement. This is also a standard method used
6 across the industry to model depreciation expense for transmission,
7 distribution and general plant assets.

8
9 For general plant accounts (other than structures), Xcel Energy uses vintage
10 group accounting as granted under Federal Energy Regulatory Commission
11 ("FERC") Accounting Release No. AR-15. Vintage group accounting is
12 simply a means of more efficiently accounting for low dollar investment cost,
13 high volume assets that are commonly found in General Plant accounts.
14 Under vintage group accounting, assets are amortized by vintage year of
15 installation over their projected useful life and retired at the end of the last
16 amortization period. The analysis of useful life of vintage group property is
17 based on the forecast method. That is, the future retirement date is
18 forecasted utilizing a review of retirement forces and future uses of property
19 by field personnel familiar with the equipment in determining the appropriate
20 recovery period.

21
22 Q. IS MR. KING'S RECOMMENDATION FOR THE COMPANY TO MOVE FROM A
23 WHOLE-LIFE CALCULATION TO A REMAINING-LIFE CALCULATION FOR
24 TRANSMISSION, DISTRIBUTION AND GENERAL PLANT STRUCTURES
25 APPROPRIATE?

26 A. No. The whole-life technique is one of the two standard techniques used in
27 the industry and is no less valid than the remaining-life technique Mr. King is

1 suggesting for the Company. Both the whole-life and remaining-life
2 techniques will fully recover the initial cost of the assets over the life of the
3 assets. The remaining-life technique requires more precision in the estimated
4 life and dispersion of retirements than the whole-life technique requires and
5 would consequently be somewhat more burdensome. Both techniques are
6 fully described in all authoritative utility depreciation texts and are used by
7 companies across the industry. The whole-life technique has also been used
8 by Xcel Energy and approved by the North Dakota Public Service
9 Commission (the "Commission") for a number of years. There is no
10 compelling reason to force Xcel Energy to change methods.

11
12 Q. WHEN WAS THE FIRST TIME XCEL ENERGY USED A WHOLE-LIFE APPROACH
13 FOR DEPRECIATION CALCULATIONS?

14 A. Xcel Energy's depreciation rates have been based on this approach (and
15 approved by the Commission) in every case since the beginning of
16 Commission regulation in North Dakota. There is no evidence to suggest
17 that the Commission should order Xcel Energy to change its depreciation
18 method.

19 IV. GENERATION LIVES

20
21 Q. HOW DOES XCEL ENERGY DETERMINE ITS GENERATING UNIT RETIREMENT
22 DATES?

23 A. Each year, Xcel Energy is required to reexamine the remaining lives of its
24 generating units based on the facts and circumstances surrounding each unit.
25 Some of the components examined are:

- 26 • Fuel and fuel resource changes

- 1 • System capacity requirements
- 2 • Pollution control equipment and environmental standards
- 3 • Major construction projects
- 4 • Major replacement and repair projects
- 5 • Maintenance programs for plant equipment
- 6 • Other related contracts tied to operating life

7 When any new production plant goes into service, an initial life is set based
8 on consideration of function (i.e. base load for Sherco, peaking for
9 combustion turbines), fuel and system capacity, along with other factors. In
10 addition, the Company conducts a detailed Integrated Resource Planning
11 study to determine the projected lives of all of its generating units. As part of
12 its annual remaining life update study, the Company also interviews plant
13 management to determine if any conditions in the plant have changed to
14 warrant a change in retirement date for any generating unit.

15
16 Q. MR. KING RECOMMENDS EXTENDING THE LIFE OF THE THREE SHERCO
17 GENERATING UNITS SIGNIFICANTLY FROM 44 YEARS (FOR TWO OF THE UNITS)
18 AND 33 YEARS (FOR THE THIRD UNIT) TO 59 YEARS. ARE THESE CHANGES
19 REASONABLE OR APPROPRIATE?

20 A. No. Based on the facts and circumstances surrounding each Sherco
21 generating unit, the Company set a retirement date for each generating unit
22 using the above-described process. In contrast, the 59 years proposed by Mr.
23 King, is simply his calculated average for all steam generating units retired in
24 the last 106 years. This Commission should make a decision on the life of the
25 Sherco generating units based on a consideration of the facts and
26 circumstances of each generating unit, not on a calculated industry average

1 made up of multiple types of steam generation with different technologies
2 and forces driving retirement. To extend the life of these units without taking
3 into account the facts and circumstances surrounding the plant would be
4 unreasonable. In addition, there are still a number of unknowns surrounding
5 environmental regulation. Extending coal unit lives significantly (for Sherco
6 Unit 3, the proposed increase nearly doubles the life) without first gaining an
7 understanding of the scope or impact of the new environmental
8 requirements that will be forthcoming would be unreasonable.

9
10 Q. PLEASE EXPLAIN WHY A STATISTICAL INDUSTRY AVERAGE IS INAPPROPRIATE
11 FOR SETTING THE DEPRECIABLE LIVES OF THE COMPANY'S GENERATING
12 UNITS?

13 A. Generating plants owned by the Company are few in number, individually
14 unique in age, location, operating characteristics and capital improvement
15 history; making statistical averaging of little value in attempting to set the
16 appropriate remaining life for each unit. To make an analogy, one could
17 analyze the retail electric rates charged customers across the United States,
18 performing historical trend analysis and industry-wide averaging to propose
19 what rate the Company should be charging in North Dakota. The results of
20 this analysis may indicate that the Company should be granted a 15% rate
21 increase. This approach would be totally contrary to sound ratemaking
22 principles as it lacks the direct connection to the Company's underlying cost
23 structure necessary to provide retail electric service. Similarly, using industry
24 averages to set depreciation rates, also lacks the direct connection to the
25 Company's specific generating unit facts.

26

1 Mr. King has taken the statistical average of a wide range of historical
2 retirement ages (units retiring at ages ranging from 18 years to 69 years) from
3 the past 106 years and applied that average to one plant. In reality, the
4 average life will not be the appropriate life for this plant or any individual
5 plant. Unlike the statistical process used in the transmission and distribution
6 accounts, using statistics to determine a retirement date for a generating unit
7 is inappropriate. In the transmission and distribution accounts, this same
8 type of statistical analysis can be applied to provide useful historic
9 information for consideration in determining the appropriate average service
10 life for plant asset accounts containing large numbers of similar assets. It is
11 this large volume of similar assets owned by the Company in the various
12 transmission and distribution plant asset accounts (each having a discrete
13 retirement date) that allows statistical analysis such as the one used by Mr.
14 King (i.e. actuarial analysis) to be used effectively to analyze the average
15 service lives because a statistically valid sample can be developed. The result
16 of this analysis is then applied against a large volume of discrete assets where
17 the deviations from actual experience are expected to be offsetting, not single
18 assets (like generating plants) where deviations are not offset by other
19 deviations. In his testimony, Mr. King provides evidence that averages do
20 not fit individual units. More specifically, he states that Xcel Energy's
21 generating unit "lives range from 44 to 99 years."¹ Mr. King does not
22 challenge the retirement dates of other steam plant and accepts that the
23 Company's other units will not retire at the average age.

24

¹ Direct Testimony of Mr. King, page 22, line 7.

1 Q. WHAT ADDITIONAL CONCERNS DO YOU HAVE WITH MR. KING'S
2 RECOMMENDATION TO EXTEND CERTAIN GENERATING PLANT REMAINING
3 LIVES BASED ON INDUSTRY AVERAGES?

4 A. Mr. King's application of an industry-wide study to certain Xcel Energy
5 generating facilities is not appropriate and should be rejected because:

- 6 • His proposal lacks correlation with the Company's resource
7 planning process.
- 8 • His proposal does not properly address the correlation
9 between capital spending and life extension.
- 10 • The proposal is being selectively applied to certain units and
11 not others.

12

13 Q. PLEASE EXPLAIN HOW GENERATING PLANT DEPRECIATION CORRELATES
14 WITH RESOURCE PLANNING.

15 A. As the Company assesses how it plans to meet the future energy
16 requirements of its customers, decisions to spend the capital required to
17 extend the life of existing generating plants is weighed against purchased
18 power alternatives as well as new generating plant construction.
19 Consideration is given to fuel type, location relative to load and
20 infrastructure, environmental impacts, expected life and ultimate cost, just to
21 name a few key considerations. It is through this process that the Company
22 decides whether to extend the life of existing generating units. For
23 example, the Company used this process before deciding to spend
24 considerable capital and work toward obtaining all of the regulatory
25 approvals and Nuclear Regulatory Commission ("NRC") operating license
26 extensions to extend the lives of the Monticello and Prairie Island nuclear
27 generating plants.

1 Q. PLEASE EXPLAIN HOW GENERATING PLANT DEPRECIATION CORRELATES
2 WITH CAPITAL SPENDING.

3 A. Major lengthening of generating unit remaining lives are usually the result of
4 decisions made in the resource planning process to spend significant amounts
5 on capital improvements to achieve an extended operating period and meet
6 environmental operating requirements. As with most types of equipment, if
7 money is spent to replace the major operating components, the expected life
8 will be extended. For example, a unit may need to be retired after 35 years
9 based on original equipment condition, however, may run for 50-60 years if
10 the Company decides to spend considerable capital on major components to
11 achieve the longer life. In general, generating units will not operate over an
12 extended life absent the decision to spend considerable capital to achieve the
13 longer life and depreciation rates should not be arbitrarily lengthened prior to
14 that spending taking place.

15

16 Q. CAN YOU PROVIDE A CONCRETE EXAMPLE?

17 A. Yes. The Allen King plant was installed in 1968. Ms. Elizabeth Engelking
18 testifies that the plant was approaching the end of its operating life and would
19 have been forced to retire. The Company made a conscious planning decision
20 to spend \$471.7 million, which permitted a 22-year life extension in 2007
21 resulting in a total life span of 69 years. Mr. King has proposed life
22 extensions that could not be accomplished without significant capital
23 expenditures, which would, of course, act as an offset to the reduction in
24 depreciation expense.

25

1 Q. HAS THE COMPANY INVESTIGATED THE TYPES OF CHANGES THAT WOULD
2 NEED TO BE MADE TO SHERCO UNITS 1, 2 AND 3 IN ORDER FOR THEM TO
3 HAVE LIFE EXTENSIONS TO 59 YEARS?

4 A. Yes. We would expect to replace turbine stationary and rotating components
5 at least once on all three units; generator, main, and reserve transformers
6 would be replaced at least once on all three units; cooling towers would be
7 replaced at least once on all three units; boiler sections would be replaced
8 once on unit 3, and possibly twice on units 1 and 2; control systems would be
9 replaced at least twice on all three units; ash disposal systems (ash storage
10 ponds and ash landfills) would need to be expanded; fuel handling and
11 processing equipment would need upgrades; selective catalytic reduction
12 equipment would be needed to reduce NO_x emissions; and infrastructure
13 (roads, buildings, communications) replacements would need to be made. All
14 of these are included in the Company's capital project plans for the future.

15

16 Q. ARE THERE OTHER CONCERNS WITH RESPECT TO THE UNITS MR. KING
17 PROPOSED TO APPLY THE INDUSTRY AVERAGE TO?

18 A. Yes. Although I would not recommend applying an industry average to any
19 generating unit, it is not clear to me why such an average would be
20 appropriate for some units and not others.

21

22 Q. MR. KING RECOMMENDS EXTENDING THE LIFE OF THE OTHER COMBUSTION
23 TURBINE PRODUCTION PLANTS TO 45 YEARS. ARE THESE CHANGES
24 REASONABLE OR APPROPRIATE?

25 A. No. Mr. King recommends a life extension for five combustion turbine
26 plants. In one case, his recommendation, which is again based on using the
27 average life of all combustion turbine plants in his study, results in over a 75%

1 increase in the life of a unit. As discussed above, Xcel Energy has a rigorous
2 process that is conducted annually to examine the facts and circumstances
3 surrounding each generating unit to determine its retirement date. For the
4 Company's combustion turbine plant (normally peaking plants), the operation
5 time, maintenance, fuel source and costs, and system demand, as well as the
6 plants system capability will impact the service life of these production plants.
7 As with the Sherco units, the five combustion turbine plants recommended
8 for life extension by Mr. King have been continuously reviewed by the
9 Company. In addition, the same issues discussed above with respect to the
10 use of his industry average study for the Sherco plant apply to the study's use
11 for the combustion turbine units. Finally, a significant capital expenditure
12 would be required before a major life extension would be warranted.
13 Therefore, Mr. King's treatment of generation as if they were generic in
14 nature should be rejected and the Company's specific lives adopted.

15
16 Q. HAS THE COMPANY INVESTIGATED THE TYPES OF CHANGES THAT WOULD
17 NEED TO BE MADE TO THE OTHER PRODUCTION PLANTS IN ORDER FOR THEM
18 TO HAVE LIFE EXTENSIONS TO 45 YEARS?

19 A. Yes. Eight of the units would need to undergo major overhauls. In addition,
20 those units would need to be able to run for 24 consecutive months in the
21 previous 5 years to avoid triggering new source review from an environmental
22 perspective. If that were to happen, it would not be economical to restore
23 and run these units with the best available control technology. Life
24 extensions for the other units are expected to be addressed through
25 continued aggressive maintenance but would require upgrades of control
26 systems, replacement of inlet silencers and exhaust diffusers, and replacement
27 auxiliary coolers.

1 Q. HAS XCEL ENERGY MADE A 2008 PRODUCTION REMAINING LIFE FILING WITH
2 THE MINNESOTA COMMISSION?

3 A. Yes. After this rate case was filed in North Dakota, Xcel Energy filed an
4 updated remaining life filing with the Minnesota Public Utilities Commission.
5 In that filing, Xcel Energy extended the lives of various units based on the
6 current facts and circumstances surrounding those units. Below are the
7 retirement dates used in the depreciation study incorporated in this rate case
8 filing and those filed in Minnesota in February 2008.

9

10		Present Retirement	Proposed Retirement
11	Unit	<u>Date</u>	<u>Date</u>
12	Sherco 1 & 2	2019	2022
13	Sherco 3	2020	2022
14	Blue Lake 1-4	2010	2012
15	Key City	2009	2012
16	Granite City	2009	2012

17

18 Q. IS XCEL ENERGY WILLING TO INCORPORATE THESE NEW LIVES FILED IN
19 MINNESOTA IN FINAL RATES RESULTING FROM THAT REQUEST INSTEAD OF
20 THOSE EMBEDDED IN THE CURRENT TEST YEAR?

21 A. Yes. It is highly likely that the results of this filing will be known prior to
22 setting final rates in this case. The Company will incorporate in its
23 compliance filing the North Dakota jurisdictional depreciation reduction in
24 setting final rates.

25

26 Q. SHOULD THE LIFE OF PRAIRIE ISLAND BE EXTENDED TO 60 YEARS PRIOR TO
27 RECEIVING A LICENSE EXTENSION FROM THE NRC?

1 A. No. It is premature to extend the life of Prairie Island. At this time, it is still
2 speculative to assume, as a regulated utility, that Prairie Island will be granted
3 a life extension. There is a significant effort required to obtain a life
4 extension. It is not guaranteed. The work and expense involved in filing for
5 an extension and actually extending the life of a nuclear plant is massive.
6 Prairie Island will need to make considerable capital improvements to realize
7 a twenty-year life extension and meet the NRC license extension
8 requirements. The current estimate to extend the life of Prairie Island is
9 approximately \$180 million.² As described above, until these costs are
10 incurred, extending the life would create a mismatch between the realizable
11 life and the investment made to realize that life.
12

13 V. DISTRIBUTION LIVES

14
15 Q. WOULD AN INCREASE IN AVERAGE SERVICE LIFE TO 40 YEARS FOR OVERHEAD
16 CONDUCTORS AND DEVICES, AS MR. KING SUGGESTS, BE APPROPRIATE DUE
17 TO AN INCREASE IN EXPENSES FOR THE TREE-TRIMMING PROGRAM?

18 A. While this change may sound appropriate on the surface, it is based on a
19 misunderstanding of the forces that cause retirement of distribution lines at
20 Xcel Energy. Very few of the retirements of distribution overhead
21 conductors are caused by trees hitting lines that are preventable by a cyclical
22 tree-trimming program. The root-cause analysis for tree-related outages is
23 tracked by the Vegetation Management Department of Xcel Energy. That
24 Department investigates every outage involving trees and power lines. One
25 of the main objectives of these investigations is to determine whether the
26 outage was preventable or not. Simply stated, a preventable event is an event

² Direct Testimony of Mr. Charles Bomberger, pages 15-16.

1 that could have been prevented if Xcel Energy had performed routine
2 maintenance on the tree in question the day before the event occurred. Non-
3 preventable tree-related outages typically occur from live broken limbs
4 outside of the normal maintenance zone or uprooted trees outside the right-
5 of-way where the Company could not reasonably predict their failure. Since
6 2002, Xcel's root-cause investigation of the actual events in North Dakota
7 suggests that 80% (40 out of 50) were non-preventable events. In other
8 words, very few of the retirements caused by trees hitting distribution lines
9 are preventable by a more aggressive tree trimming program. Although there
10 are many other positive benefits from focusing more efforts on tree trimming,
11 reducing the level of retirements caused by trees damaging distribution
12 conductors is not one of them. In reality, non-preventable damage from
13 storms, ice loading and other non-tree clearance issues are the drivers of
14 retirements for overhead conductors. These causes are not affected by tree
15 trimming. Although it sounds plausible, the fact that tree-trimming expenses
16 are higher will not materially affect the life of distribution overhead
17 conductors. The facts do not warrant the change Mr. King is suggesting.
18

19 VI. DEPRECIATION STUDIES AND CUSTOMER RATES

20
21 Q. MR. MAJOROS, ON PAGE 7 OF HIS DIRECT TESTIMONY, RECOMMENDS THAT
22 THE COMMISSION REQUIRE THE COMPANY TO FILE A SEPARATE
23 DEPRECIATION STUDY IN NORTH DAKOTA. DO YOU AGREE WITH THIS
24 RECOMMENDATION?

25 A. No. Base on my numerous years of experience in the areas of depreciation
26 and rate regulation, I believe that setting North Dakota specific depreciation

1 rates would create numerous regulatory inconsistencies, be detrimental to our
2 North Dakota customers and also detrimental to the Company.

3
4 Q. WHAT SPECIFIC REGULATORY INCONSISTENCIES WOULD BE CREATED FROM
5 USING DIFFERENT DEPRECIATION RATES IN NORTH DAKOTA?

6 A. First, all generation assets, transmission assets and the vast majority of
7 common and general assets are shared across all jurisdictions. Using a
8 generating plant as an example, the current practice used to set rates in North
9 Dakota is to use a single depreciation expense calculation that first allocates
10 the intercompany sharing of this cost between NSP-Minnesota (Minnesota,
11 North Dakota and South Dakota) and NSP-Wisconsin (Wisconsin and
12 Michigan). The amount allocated to NSP-Minnesota is then allocated to the
13 Minnesota, North Dakota and South Dakota retail jurisdictions as well as the
14 FERC wholesale jurisdiction based on demand. If North Dakota were to
15 order different depreciation rates, the process that I just described will need to
16 be abandoned. It would be necessary to set up jurisdictional specific
17 accounting records for depreciation expense and accumulated provision for
18 depreciation to insure that the appropriate level of depreciation being
19 recovered from North Dakota ratepayers is being properly tracked. As
20 demand percentages change, additional regulatory guidance would be needed
21 to reconcile the inconsistency between jurisdictional specific depreciation
22 rates and system allocated costs.

23
24 Q. PLEASE EXPLAIN WHY YOU BELIEVE A NORTH DAKOTA REQUIRED
25 DEPRECIATION STUDY AND DIFFERENT NORTH DAKOTA SPECIFIC
26 DEPRECIATION RATES WOULD BE DETRIMENTAL TO NORTH DAKOTA
27 CUSTOMERS?

1 A. If the Commission decides to depart from its long-standing practice of
2 allowing the Company to set depreciation rates on a Company-wide basis, a
3 number of consequences to that decision should be considered. First, and
4 most importantly, if depreciable lives are set too long relative to the current
5 capital employed, customers will see an immediate rate reduction due to the
6 lower depreciation expense, but at a future cost. With the slower capital
7 recovery, customers will be required to sponsor a higher return and taxes as
8 rate base will decline slower with the longer lives (accumulated depreciation is
9 a reduction to rate base). Then as the Company makes future capital
10 decisions to either replace the asset or spend the capital required to extend an
11 asset's life, future customers will still be responsible for the un-depreciated
12 value and need to pay costs associated with both the old asset as well as the
13 new asset, or not receive the benefits of a planned life extension as the life
14 extension will have been already assumed. Second, as mentioned above,
15 having a separate depreciation study and North Dakota specific accounting
16 will generate additional North Dakota specific regulatory costs to review the
17 study, implement jurisdiction specific rates and a jurisdictional specific asset
18 accounting process.

19

20 Q. PLEASE EXPLAIN WHY YOU BELIEVE A NORTH DAKOTA REQUIRED
21 DEPRECIATION STUDY AND DIFFERENT NORTH DAKOTA SPECIFIC
22 DEPRECIATION RATES WOULD BE DETRIMENTAL TO THE COMPANY?

23 A. With the implementation of North Dakota specific depreciation rates, the
24 Company will be required to implement jurisdictional specific accounting to
25 insure that each jurisdictional customer base is equitably treated as to the
26 amount of capital previously recovered and the Company can track the

1 recovery of its capital investments. Such jurisdictional specific accounting will
2 be more costly and burdensome compared to the current process.

3
4 Q. HAS THE COMPANY INCREASED ITS EFFORTS TO KEEP THE COMMISSION
5 INFORMED ON ITS DEPRECIATION FILINGS WITH THE MINNESOTA
6 COMMISSION?

7 A. Yes. In response to concerns raised during our most recent natural gas case
8 (Docket PU-06-1429) the company has copied the Commission on all
9 depreciation filings made in Minnesota, and we stand ready to address any
10 questions or concerns that those filings may cause.

11 12 VII. CONCLUSION

13
14 Q. WHAT ARE YOUR CONCLUSIONS WITH REGARD TO DEPRECIATION STUDIES,
15 DEPRECIATION METHOD AND DEPRECIABLE LIVES AS THEY PERTAIN TO THIS
16 CASE?

17 A. Based on the various reasons stated above, I recommend that the
18 Commission accept the depreciation methodology and asset lives proposed by
19 the Company. In addition, I recommend that the Commission continue its
20 long-standing approach to depreciation by allowing the Company to utilize a
21 single set of depreciation rates and defer the review of rates and methods to
22 the Company's largest jurisdiction while keeping North Dakota informed and
23 involved in this process. This process has served North Dakota customers
24 well by providing the proper balance between capital recovery and capital
25 employed and has helped insure that the recovery of capital has correlated
26 with providing electric service and that material unrecovered balance of assets
27 retired were not added to the obligation of future ratepayers.

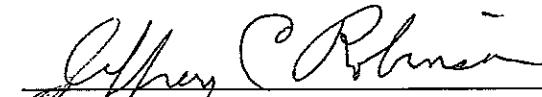
- 1 Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?
- 2 A. Yes, it does.

1
2 STATE OF NORTH DAKOTA
3 BEFORE THE
4 PUBLIC SERVICE COMMISSION
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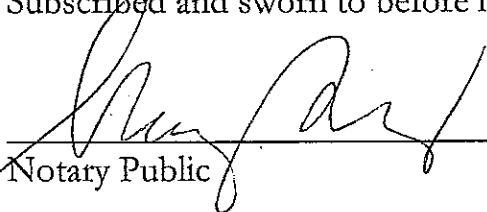
7 In the Matter of)
8 Northern States Power Company ,)
9 A Minnesota corporation and wholly owned) Case No. PU-07-776
10 Subsidiary of Xcel Energy Inc.)
11 For Authority to Increase Rates for)
12 Natural Gas Service in North Dakota)
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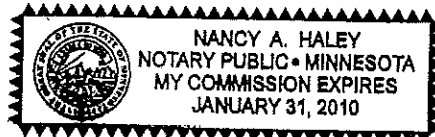
16 AFFIDAVIT OF
17 Jeffrey C. Robinson
18
19

20 I, the undersigned, being duly sworn, depose and say that the foregoing is
21 the Direct Testimony of the undersigned, and that such Direct Testimony and the
22 exhibits or schedules sponsored by me to the best of my knowledge, information
23 and belief, are true, correct, accurate and complete, and I hereby adopt said
24 testimony as if given by me in formal hearing, under oath.
25
26
27

28 
29 Jeffrey C. Robinson
30
31
32
33

34 Subscribed and sworn to before me, this 13 day of June, 2008.
35
36
37

38 
39 Notary Public



Northern States Power Company, a Minnesota corporation and wholly owned subsidiary of Xcel Energy Inc.
Resume of Mr. Jeffrey C. Robinson

Case No. PU-07-776
Exhibit__(JCR-2), Schedule 1
Page 1 of 3

Independent Contract
January, 2007 - current
Xcel Energy Retiree (employed 9/72 – 12/06)

Jeffrey C Robinson LLC
1270 Kolff Ct
Newport, MN 55055

Current Responsibilities

Since my retirement from Xcel Energy Services Inc. (“XES” or the “Service Company”) as Manager of Revenue Analysis at the end of 2006, I have been providing support to the Regulatory area of XES on a part-time contract basis. This has included overall revenue requirements testimony in North Dakota and Minnesota as well as assisting with a variety of regulatory petitions related to cost recovery and accounting.

In my most recent position as manager of Revenue Analysis which I held from 1994-2006, I was responsible for the general administration of the Revenue Analysis area and for the preparation and presentation of cost of service studies, revenue requirement determinations and jurisdictional annual reports for electric and gas rates filed on behalf of Northern States Power Company, Minnesota, with the Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission, the South Dakota Public Utilities Commission and the Federal Energy Regulatory Commission (FERC).

Previous Employment (1972-1994)

Operations Analyst - NSP
Tax Depreciation Analyst - NSP
Manager, Depreciation Services - NSP
Manager, Depreciation & Nuclear Fuel Accounting - NSP
Manager, Corporate Economics and Depreciation - NSP
Manager, Capital Asset Accounting – NSP
Manager, Revenue Requirements – NSP
Manager, Revenue Analysis – XES

Education

University of Wisconsin, River Falls - Bachelor of Science
Major - Mathematics

Certifications

Certified Depreciation Professional (1997-2003)

Professional Associations and Registrations

Past Chair - Edison Electric Institute, Depreciation Accounting Committee (1984-1985)
Society of Depreciation Professionals

Articles or Papers Published or Presented

Jeffrey C. Robinson, “A Sinking Fund Approach to Nuclear Fuel Disposal Recovery,” Iowa State University Regulatory Conference 1980 - Vol. 19. May 1980.

Jeffrey C. Robinson, "A Sinking Fund Approach to Nuclear Fuel Disposal Recovery," A.G.A. - EEI Depreciation Accounting Committee, Journal of Papers - Administration Year 1980 -1981, Vol. 2, June 1980.

Jeffrey C. Robinson, "Mechanized Depreciation Accounting Systems," A.G.A. - EEI Depreciation Accounting Committee, Journal of Papers - Administrative Year 1980-1981, Vol. 2, February 1981.

Jeffrey C. Robinson, "Revenue Requirements Related to Unit-Of-Production Depreciation," A.G.A. - EEI Depreciation Accounting Committee, Journal of Papers - Administrative Year 1981-1982, Vol. 3, February 1982.

Jeffrey C. Robinson and Cheryl R. Hatfield, "Economic Comparison of Nuclear Decommissioning Funding Alternatives," Proceedings of the A.G.A. Depreciation and EEI Depreciation Accounting Committee, Administrative Year 1986-1987, Vol. 8, September, 1987.

Jeffrey C. Robinson, "Economic Evaluation of Power Plant Life Extension," Proceedings of the A.G.A. Depreciation and EEI Depreciation Accounting Committee, Administrative Year 1987-1988, Vol. 9, September, 1988.

Previous Testimony

FERC, Nuclear Fuel Disposal, Docket No. ER81-651-000, 1981
FERC, Nuclear Fuel Disposal, Docket No. ER81-653-000, 1981
FERC, Tax Normalization, Docket No. ER88-72-000, 1988
FERC, Nuclear Decommissioning, Docket No. ER88-75-000, 1988

Minnesota, Ramsey County District Court, Depreciation, File No. 456710, 1984
Minnesota, Nuclear Decommissioning, Docket No. E002/GR-87-670, 1987
Minnesota, Nuclear Decommissioning, Docket No. E002/GR-89-865, 1989
Minnesota, Nuclear Fuel Storage, Docket No. E002/CN-91-19, 1991
Minnesota, Depreciation and Nuclear Decommissioning, Docket No. E002/GR-92-1185, 1992
Minnesota, Pre-Merger Revenue Requirements, Merger Rate Plan, Savings Allocations, Docket No. E,G-002/PA-95-500, 1995
Minnesota, Rate Base, Docket No. G002/GR-97-1606, 1997
Minnesota, Overall Revenue Requirements, Rate Base, Income Statement, Docket No. G002/GR-04-1511, 2004
Minnesota, Overall Revenue Requirements, Rate Base, Income Statement, Docket No. E002/GR-05-1428, 2005
Minnesota, Overall Revenue Requirements, Rate Base, Income Statement, Docket No. G002/GR-06-1429, 2005

Northern States Power Company, a Minnesota corporation and wholly owned subsidiary of Xcel Energy Inc.
Resume of Mr. Jeffrey C. Robinson

Case No. PU-07-776
Exhibit__(JCR-2), Schedule 1
Page 3 of 3

North Dakota, Depreciation, Docket No. 10,979, 1987

North Dakota, Overall Revenue Requirements, Rate Base, Income Statement, Case No. PU 400-04-578, 2004

North Dakota, Overall Revenue Requirements, Rate Base, Income Statement, Case No. PU-06-525, 2005

South Dakota, Nuclear Decommissioning, Docket No. F-3764, 1988

Rebuttal Testimony
Allen D. Krug

Before the North Dakota Public Service Commission
State of North Dakota

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

For Authority to Increase Rates for
Electric Service in North Dakota

Case No. PU-07-776
Exhibit___

Wholesale Margins

June 13, 2008

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II.	Regulatory Treatment of Wholesale Margins	1
III.	Summary and Conclusions	4

1 **I. INTRODUCTION**

2
3 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

4 A. My name is Allen D. Krug. My business address is 414 Nicollet Mall,
5 Minneapolis, Minnesota 55401.

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 (“Xcel Energy” or the “Company”) a Minnesota corporation operating in
10 North Dakota.

11
12 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

13 A. I will discuss the recommendations made by witness Mr. Michael Majoros
14 regarding the ratemaking treatment of wholesale margins.

15
16 **II. REGULATORY TREATMENT OF WHOLESALE MARGINS**

17
18 Q. PLEASE PROVIDE A SUMMARY OF YOUR REBUTTAL TESTIMONY.

19 A. My Rebuttal Testimony addresses the recommendations made by
20 Mr. Majoros, presented on behalf of the Advocacy Staff of the North Dakota
21 Public Service Commission (the “Commission”) regarding wholesale margins,
22 as stated on page 22, lines 13 – 16, of his Direct Testimony.

23
24 Q. PLEASE SUMMARIZE MR. MAJOROS’ RECOMMENDATIONS REGARDING
25 WHOLESALE MARGINS.

26 A. On page 22, lines 13–16 of his testimony, Mr. Majoros appears to recommend
27 that 100 percent of wholesale margins be returned to customers through the

1 Fuel Cost Rider (“FCR”). Though he does not specifically differentiate
2 between asset-based and non-asset-based margins, I presume that his
3 recommendation applies to both types. While Mr. Majoros does not propose
4 any sharing of wholesale margins between customers and shareholders, his
5 recommendation is supportive of my proposal to pass the benefits of actual
6 realized wholesale margins to customers through the FCR.

7
8 Q. PLEASE COMMENT ON MR. MAJOROS’ RECOMMENDATION REGARDING
9 MARGINS DERIVED FROM ASSET-BASED SALES.

10 A. In my Direct Testimony, I proposed shareholder retention of 15 percent of
11 the margins derived from asset-based sales. I made this recommendation to
12 more closely align the interests of shareholders and ratepayers, as we attempt
13 to optimize the use of our generation resources in the wholesale market.
14 Incentive regulation and the accompanying alignment of shareholder and
15 ratepayer interests is an important policy goal and has previously been
16 encouraged by the Commission in other proceedings. However, I understand
17 Mr. Majoros’ concern with increasing costs and their impact on our
18 customers. The Company also wishes to do everything possible to keep rates
19 as low as possible, while still maintaining reliable service for all of our
20 customers. Therefore, the Company is willing to adopt Mr. Majoros’
21 recommendation, should the Commission no longer wish to pursue this policy
22 goal.

23

1 Q. PLEASE COMMENT ON MR. MAJOROS' RECOMMENDATION REGARDING
2 MARGINS DERIVED FROM NON ASSET-BASED SALES.

3 A. I believe that non asset-based transactions, as defined in my Direct Testimony,
4 are quite different in nature from asset-based transactions and merit alternative
5 treatment. These transactions do not rely on the generating assets of the
6 Company and do require a certain level of market knowledge and risk taking
7 on behalf of the Company. In my Direct Testimony, I proposed returning 15
8 percent of the net aggregate margins derived from non asset-based trading to
9 customers. Further, I proposed that customers only participate in net
10 aggregate gains, not losses, thus ensuring that customers cannot be harmed by
11 this activity. While I share Mr. Majoros' concerns regarding cost increases for
12 our customers, I believe that the unique nature of non asset-based activity,
13 which is a non-regulated activity, merits an incentive mechanism. Further, as
14 discussed above, my proposal is consistent with the Commission's historical
15 support for incentives as an effective regulatory tool.

16

17 Q. BASED ON THE ABOVE DISCUSSION, WHAT IS YOUR POSITION REGARDING THE
18 REGULATORY TREATMENT OF NON ASSET-BASED SALES?

19 A. I continue to recommend a sharing mechanism for margins derived from non
20 asset-based activity. Consistent with my recommendation provided in my
21 Direct Testimony, I recommend that 15 percent of these margins be shared
22 with customers through the FCR, and that customers bear no risk of net
23 aggregate losses in a calendar year.

24

1 **III. SUMMARY AND CONCLUSIONS**

2

3 Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

4 A. I recommend adoption of Mr. Majoros' recommendation regarding margins
5 derived from asset-based sales, should the Commission no longer wish to
6 pursue its current policy regarding incentives. I continue to recommend that
7 15 percent of the margins derived from non asset-based sales be returned to
8 ratepayers through the fuel clause.

9

10 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

11 A. Yes, it does.

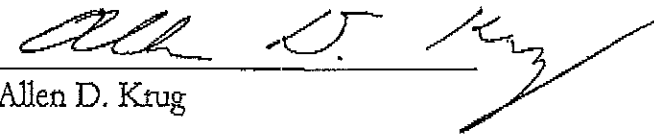
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STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

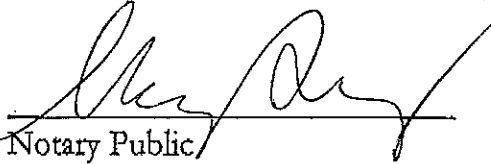
In the Matter of the Application of Northern)
States Power Company, a Minnesota Corporation)
For Authority to Increase Rates for Electric Service) Case No. PU-07-776
in North Dakota)

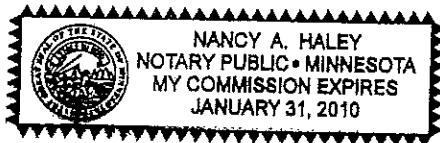
AFFIDAVIT OF
Allen D. Krug

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


Allen D. Krug

Subscribed and sworn to before me, this 12 day of June, 2008.


Notary Public



Rebuttal Testimony and Schedules
Anne E. Heuer

Before the North Dakota Public Service Commission
State of North Dakota

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

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

Case No. PU-07-776
Exhibit___

Overall Revenue Requirements
Rate Base
Income Statement

June 13, 2008

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1 **I. INTRODUCTION AND QUALIFICATIONS**

2
3 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

6
7 Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

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

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

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

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

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

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

- 1 • Provide our calculations of the impact of the recommendations of Mr. King
2 and Mr. Majoros on our revenue requirement, correcting certain estimates
3 and calculations of the adjustments offered by Mr. Majoros in his Testimony;
4 and
5 • Provide the updated revenue deficiency recommended by the Company for
6 adoption in this case.

7
8 Other Xcel Energy witnesses will respond to each of the other issues raised by
9 Mr. King and Mr. Majoros.

10
11 Q. HOW IS YOUR REBUTTAL TESTIMONY ORGANIZED?

12 A. I first present the Company's response to nine substantive issues raised by Mr.
13 King and Mr. Majoros. I then correct the allocation of costs related to chemicals
14 used during the pollution control process at the Allen S. King Plant. I next
15 present the actual, corrected revenue requirement impacts of Mr. King and Mr.
16 Majoros' various recommendations, so that the Commission has an accurate
17 record for consideration in this proceeding. Finally, I summarize the overall
18 revenue deficiency recommended by the Company, reflecting the changes
19 offered in my Rebuttal Testimony.

20
21 **II. FINANCIAL RECOMMENDATIONS**

22
23 **A. Pole Inspection and Replacement and Cable Replacement**

24
25 Q. WHAT DID MR. MAJOROS RECOMMEND REGARDING THE COMPANY'S POLE
26 INSPECTION AND REPLACEMENT AND CABLE REPLACEMENT PROGRAMS?

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

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

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

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

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

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

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

1 **101 Electric plant in service**

2 A. This account *shall include the original cost* of electric plant, included in
3 accounts 301 to 399, prescribed herein, owned and used by the utility in
4 the electric utility operations, and *having an expectation of life in service of more*
5 *than one year from the date of installation*, including such property owned by
6 the utility but held by nominees.
7

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

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

13 E. *The utility is restricted in its use of the accumulated provision for depreciation to the*
14 *purposes set forth above.* (Emphasis added).
15

16 The costs associated with new poles and cable, such as the costs reflected in our
17 Pole and Cable Replacement Programs, are for new equipment that will provide
18 service to our customers over its useful life. As such, the FERC Uniform System
19 of Accounts would require that such investments be recorded in the appropriate
20 property account, and depreciated over their expected useful lives, rather than
21 reflected in the depreciation reserve. Costs appropriate for including in
22 depreciation reserve are the costs of actually removing a facility from service, not
23 the costs of the replacement equipment itself.
24

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

27

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

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

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

7
8 Q. WHAT IS THE COMPANY'S POSITION REGARDING THIS RECOMMENDATION?

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

14
15 Q. HOW DOES THIS CHANGE IN POSITION IMPACT CUSTOMERS?

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

18
19 **D. Nuclear Refueling Outage Costs**

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

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

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

3
4 Q. DO YOU AGREE WITH HIS RECOMMENDATION?

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

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

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

27

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

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

6

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

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

13

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

19

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

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

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

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

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

13 A. We believe the proposed amortization level of \$2,319,262¹, is the appropriate
14 level to be used for setting future rates in this case because it reflects the normal,
15 annualized level of our amortization expenses. In setting test year expense levels,
16 it is important to set costs consistent with the future time period final rates will
17 be in effect.

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

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

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

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

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

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

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

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

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

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

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

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

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

4
5 Q. DOES HE OFFER ANY EVIDENCE THAT THE COSTS WERE INACCURATELY
6 DETERMINED OR IMPRUDENTLY INCURRED?

7 A. No.

8
9 Q. DO YOU AGREE WITH HIS RECOMMENDATION?

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

15
16 Q. WERE THE COMPANY'S EFFORTS TO IMPLEMENT PRIVATE NUCLEAR FUEL
17 STORAGE APPROPRIATE?

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

² Majoros Direct Testimony at 23.

³ Id.

1 result, the recovery of those costs should not rest on having obtained advance
2 approval to incur those costs, particularly when such a requirement would be
3 imposed on an “after the fact” basis.
4

5 **F. Renewable Development Fund Expenses**
6

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

9 A. Mr. Majoros recommends that the Company’s Renewable Development Fund
10 (“RDF”) expenses in the amount of \$265,000 be disallowed because: “The RDF
11 is a Minnesota program and expenditure. It should not be charged to North
12 Dakota customers.”⁴
13

14 Q. DO YOU AGREE WITH HIS RECOMMENDATION?

15 A. No. In order to continue to operate the Prairie Island Nuclear Generating
16 Facility, which required on-site interim nuclear fuel storage, the Company was
17 required to provide funding of an RDF. The total annual funding of the RDF in
18 relation to casks located at our Prairie Island Nuclear Plant is \$16 million. The
19 operation of the nuclear plants provides substantial cost savings to all of our
20 customers, including customers in North Dakota, but saving substantial costs
21 may also require the Company to incur some costs, in this case the RDF.
22 Legislation passed in 2007 will also require the Company to provide funding of
23 \$350,000 per cask located at our Monticello Nuclear Plant⁵. We expect to be
24 required to fund \$3.5 million related to Monticello casks in 2008.
25

⁴ Majoros Direct Testimony at 23.

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

1 Q. WHAT WOULD BE THE EFFECT IF THE COMPANY REFUSED TO PROVIDE THE
2 RDF?

3 A. If the Company refused to provide that funding, the operation of the nuclear
4 generating facilities would be impossible, and the Company would be required to
5 replace approximately 1,670 MW of capacity, of which the North Dakota share is
6 82 MW. It seems obvious that the difference between the ongoing costs of
7 nuclear generation and the replacement costs would greatly exceed the \$265,000
8 of RDF costs.

9
10 Q. DOES THE REVENUE REQUIREMENT INCLUDE ALL RDF EXPENSES?

11 A. No. The test year includes \$265,000 in RDF expenses, representing the North
12 Dakota allocated share of the energy production (“EP”) grant payments and a
13 portion of the RDF administrative costs (prorated based on target funding for
14 energy production grants versus research and development (“R&D”) grants in
15 the 3rd RDF Funding Cycle Request for Proposal). The test year does not
16 include expenditures related to R&D and Renewable Energy Production
17 Incentives, which are born directly by Minnesota electric retail customers.

18
19 Q. HAVE FUNDED PARTICIPANTS IN THE RDF BEEN RESTRICTED TO MINNESOTA
20 ENTITIES?

21 A. No. In fact, nine grants from the RDF have been awarded to North Dakota
22 based projects out of 70 grants awarded. These nine projects consist on eight
23 R&D grants totaling \$6.7 million and one EP grant award of \$2 million, which
24 the prospective recipient has since chosen to decline. North Dakota based R&D
25 grants comprise approximately 20 percent of the total R&D grants awarded.
26 Please note, as I stated earlier, that R&D project expenditures are born entirely
27 by Minnesota electric customers, even though the State of North Dakota derives

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

3
4 **G. Charitable Contributions**

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

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

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

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

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

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

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

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

⁶ Majoros Direct Testimony at 22-23

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

3
4 **H. Incentive Compensation**

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

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

10
11 Q. DO YOU AGREE WITH HIS RECOMMENDATION?

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

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

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

⁷ Majoros Direct Testimony at 24.

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

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

5 **I. Income Taxes**

6

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

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

14 Q. WHAT IS THE COMPANY’S RECOMMENDATION?

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

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

22

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

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

⁹ Majoros Direct Testimony at 8

1 inadvertently included an amount that should have been assigned to the
2 Minnesota jurisdiction. I have made an adjustment that reduces North Dakota
3 expense by \$321,594 to reflect the reallocation of these costs. My calculation is
4 set forth on Exhibit (AEH-2)___Schedule 9.
5

6 III. QUANTIFICATION OF STAFF POSITION 7

8 A. Refuse Derived Fuel Generation 9

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

12 A. Mr. King recommends that the Company's investment in refuse-derived energy
13 is responsive to Minnesota mandates, should be charged to Minnesota ratepayers
14 and, therefore, should be disallowed.
15

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

17 A. The Company opposes Mr. King's recommendations for the reasons explained
18 by Ms. Engelking.
19

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

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

1 customer demand for electricity. Even if the Commission accepted Mr. King's
2 recommendation, the revenue requirement should include the cost of
3 replacement energy and lost capacity.
4

5 **B. Depreciation**
6

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

9 A. Mr. King recommends that the North Dakota depreciation expense be reduced
10 from \$19,345,000 to \$15,292,000 or by \$4,053,000. Mr. King's schedules,
11 however, calculate a new North Dakota accrual of \$15,230,000 or a reduction of
12 \$4,115,000.
13

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

15 A. The Company opposes Mr. King's recommendation for the reasons explained by
16 Mr. Jeffrey Robinson.
17

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

21 A. No. Mr. Majoros' calculation does not consider the deferred income tax effect
22 of a reduction in book depreciation as well as the effect of accumulated deferred
23 income taxes associated with a reduction in the accumulated reserve for
24 depreciation.
25

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

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

15
16 **C. Allen S. King Generating Plant**

17
18 Q. WHAT DOES MR. KING RECOMMEND WITH RESPECT TO THE ALLEN S. KING
19 GENERATING FACILITY?

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

22
23 Q. WHAT IS THE COMPANY'S POSITION WITH REGARDS TO HIS RECOMMENDATION?

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

26

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

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

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

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

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

6

7 **D. High Bridge Generating Plant**

8

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

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

14

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

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

18

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

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

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

¹⁰ King Direct Testimony at 8.

1 Whitman Index) rather than using the actual test year amount (\$369.5
2 million);

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

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

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

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

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

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

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

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

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

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

¹¹ King Direct Testimony at 13.

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

2

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

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

7

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

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

11

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

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

17

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

19

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

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

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

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

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

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

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

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

7

8 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

9 A. Yes it does.


10

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

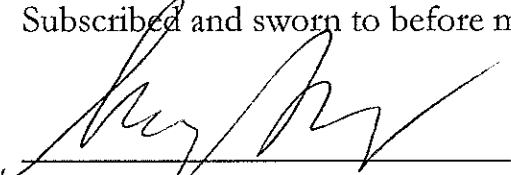
6 In the Matter of the Application of Northern)
7 States Power Company, a Minnesota Corporation)
8 For Authority to Increase Rates for Electric Service) Case No. PU-07-776
9 in North Dakota)
10
11
12

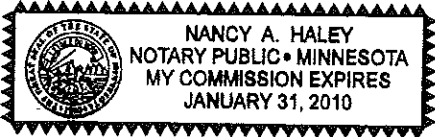
13 **AFFIDAVIT OF**
14 **Anne E. Heuer**
15
16

17 I, the undersigned, being duly sworn, depose and say that the foregoing is
18 the 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 Anne E. Heuer
26
27
28
29

30 Subscribed and sworn to before me, this 13 day of June, 2008.
31

32 
33 _____
34 Notary Public
35
36



Use of RDF Funding in North Dakota

Energy Production Projects (EP)

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

Research/Development Projects (RD)

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

Project Detail

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

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

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

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

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

RDF AWARDS

North Dakota Project Descriptions

Cycle 1

Research/Development Projects:

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

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

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

Cycle 2

Research/Development Projects:

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

Cycle 3

Energy Production Projects:

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

Research/Development Projects:

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

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

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

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

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

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

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

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

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

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

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

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

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

CORPORATE CONTRIBUTIONS	City	State	Total ND Amount	ND Electric
<u>Higher Education</u>				
Bismarck State College Foundation	Bismarck	ND	1,000	662
Boy Scouts of America, Northern Lights Council	Fargo	ND	2,000	1,324
Fargo Public Schools Development Foundation	Fargo	ND	2,500	1,655
North Dakota State University Development Foundation	Fargo	ND	16,000	10,592
Grand Forks Public Schools	Grand Forks	ND	3,000	1,986
University of North Dakota Foundation	Grand Forks	ND	10,000	6,620
Girls Scouts of Northwest North Dakota	Minot	ND	1,000	1,000
Minot Community Foundation	Minot	ND	2,000	2,000

Bismarck State College Foundation requests scholarship dollars to fund the Xcel Energy Scholarship program for the 2006-07 academic year. These scholarships would enable deserving and qualified students enrolled in the online Power Plant Technology (PWRP), Process Plant Technology (PROP) and Electrical Transmission Systems Technology (ETST) programs at Bismarck State College (BSC) to prepare for future careers in the energy industry. These online energy technology programs work with students across the nation, preparing to fill a critical shortage of trained workers in the energy industry over the next decade.

The purpose of this request is to provide scholarship support to youth who wish to participate in the Scouting program. The Northern Lights Council, Boy Scouts of America provides an age appropriate comprehensive educational program for students to build character, learn to take responsibility and develop personal fitness. The Northern Lights Council, Boy Scouts of America partners with local educators, businesses and community organizations to offer Scouting programs.

The FPS Development Foundation requests \$2,500 to provide innovative math and science grants to FPS teachers and schools. There continues to be an emphasis on the need for students to consider a career in science and math in order for American companies to remain competitive on a global basis. Providing these grants to FPS teachers and schools, not only challenges teachers to use new instructive techniques, but provide students with learning opportunities that will spark and stimulate their interest in math and science.

North Dakota State University's College of Engineering & Architecture prepares students to use their Math and Science acumen to design the future. We are requesting funds to support Xcel Energy named student scholarships for engineering students(\$15,000) and also to support the engineering students' solar car entry in the Formula Sun Grand Prix and the American Solar Challenge. (\$1,000).

The Junior Achievement Program teaches economics and the value of the free enterprise system to over 2300 elementary school students in 16 area schools in the Grand Forks area. The goal is to make our students more workforce ready and realize the important connection of education to their future success in the working world. Over 120 educators and 130 community and business volunteers partner to deliver the program.

Provide scholarships to University of North Dakota students, with an emphasis given on math, science, technology and engineering. The beneficiaries of this project are current UND students in science, math, technology and engineering. For many students, a scholarship can make a difference between attending college or not being able to pursue a degree at all due to limited resources. These are Xcel Energy named scholarships.

This grant will allow continued program development of the six weeks of summer camp. This camp is open to members as well as non-members of Girl Scouts providing opportunities for youth that would not otherwise have the opportunity to attend an educational camp. Scholarships are also provided for youth to attend this camp. The girls will earn badges pertaining to math, science, environment, financial literacy as well as other areas.

To help continue to provide the Junior Achievement program in the Minot area. The JA program helps students to understand and grasp economics and the free enterprise system.

CORPORATE CONTRIBUTIONS	City	State	Total ND Amount	ND Electric
				(1) To provide additional professional development for area educators on service learning and encourage the integration of such projects which involve participation and partnership among, students, educators, business, nonprofit entities, and community members in our area. (2) To enhance the career development program by funding a motivational speaker for 9th & 10th grade students and offering all 9th grade students career sessions hosted by local professionals addressing the knowledge and skills needed to effectively compete in the job market in their respective career fields.
Minot Public Schools	Minot	ND	2,000	2,000
Minot State University Development Foundation	Minot	ND	4,000	4,000
			<u>43,500</u>	<u>31,840</u>

Requesting funding to support student scholarships in the sum of \$4,000. These Xcel Energy scholarships will greatly assist students pursuing careers in science, mathematics, technical and/or environmental areas of study. Scholarships allow many students to pursue a more technical area of study.

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

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

0

Incentive Compensation Adjustment

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

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

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

	BOY	EOY	Average	ND Only
Rate Base				
Plus Plant In-Service	477,403,752	477,403,752	477,403,752	23,307,913
Less Book Depreciation Reserve	5,467,202	17,738,022	11,602,612	566,465
Less Accum Deferred Taxes	(2,114,362)	6,910,963	2,398,301	117,090
End Of Month Rate Base	474,050,912	452,754,767	463,402,839	22,624,358
Average Rate Base (BOY/EOY)	2008 Annual 463,402,839	ND Only 22,624,358		
Calculation of Return				
Plus Debt Return	15,523,995	757,916		
Plus Equity Return	24,699,371	1,205,878		
Total Return	40,223,366	1,963,794		
Income Statement Items				
Plus Book Depreciation	12,270,820	599,089		
Plus Deferred Taxes	9,025,326	440,636		
Plus Current Taxes	7,352,864	358,983		
Total Income Statement Expense	28,649,010	1,398,708		
Total Revenue Requirements	68,872,377	3,362,503		
Interchange Demand	84.4383%			
Jurisdiction Demand	5.7820%			
Interchange Composite Allocator	4.8822%			
Jurisdictional Revenue Requirement	3,362,503			

Tax Depreciation	33,580,463
CPI	0
Manufacturer Prod Deduct	1,022,567
Removal of Old Plant	0
State of ND Composite Tax Rate	39.225%

High Bridge-Prod	Dec-2007	Jan-2008	Feb-2008	Mar-2008	Apr-2008	May-2008	Jun-2008	Jul-2008	Aug-2008	Sep-2008	Oct-2008	Nov-2008	Dec-2008
Rate Base													
Plus CWIP Ending Balance	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Plant In-Service	0	0	0	0	0	361,136,670	364,208,687	365,651,778	367,678,463	368,171,235	368,617,071	369,062,907	369,508,709
Less Book Depreciation Reserve	0	0	0	0	0	0	0	1,040,943	2,091,604	3,150,548	4,215,547	5,286,423	6,363,101
Less Accum Deferred Taxes	(3,198,556)	(3,147,343)	(3,095,255)	(3,073,673)	(3,024,505)	(2,808,024)	(2,167,091)	(614,967)	907,544	2,430,399	3,942,724	5,435,892	6,934,907
End Of Month Rate Base	3,198,556	3,147,343	3,095,255	3,073,673	3,024,505	363,944,694	366,375,778	365,225,802	364,679,315	362,590,287	360,458,800	358,340,592	356,210,701
Average Rate Base (BOM/EOM)	3,148,114	3,172,950	3,121,299	3,084,464	3,049,089	183,484,600	365,160,236	365,800,790	364,952,558	363,634,801	361,524,544	359,399,696	357,275,647
Calculation of Return													
Plus Debt Return	8,788	8,858	8,714	8,611	8,512	512,228	1,019,406	1,021,194	1,018,826	1,015,147	1,009,256	1,003,324	997,395
Plus Equity Return	13,983	14,093	13,864	13,700	13,543	814,977	1,621,920	1,624,765	1,620,998	1,615,145	1,605,772	1,596,334	1,586,899
Total Return	22,771	22,951	22,577	22,311	22,055	1,327,205	2,641,326	2,645,959	2,639,824	2,630,292	2,615,028	2,599,658	2,584,294
Income Statement Items													
Plus Avoided Property Taxes	0	(80,417)	(80,417)	(80,417)	(80,417)	(80,417)	(80,417)	(80,417)	(80,417)	(80,417)	(80,417)	(80,417)	(80,417)
Plus Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Book Depreciation	0	0	0	0	0	0	0	1,040,943	1,050,660	1,058,945	1,064,999	1,070,876	1,076,677
Plus Deferred Taxes	(100,885)	51,213	52,089	21,582	49,167	216,481	640,933	1,552,124	1,522,511	1,522,855	1,512,324	1,493,168	1,499,015
Plus Current Taxes	650,022	500,573	516,430	558,201	554,068	598,044	411,807	(334,437)	(310,947)	(314,432)	(310,748)	(299,710)	(310,120)
Total Income Statement Expense	549,137	471,369	488,102	499,366	522,818	734,108	972,323	2,178,213	2,181,808	2,186,951	2,186,158	2,183,917	2,185,156
Total Revenue Requirements	571,909	494,320	510,679	521,677	544,873	2,061,313	3,613,649	4,824,173	4,821,632	4,817,242	4,801,185	4,783,575	4,769,450
Jurisdictional Revenue Requirement	27,238	24,134	24,932	25,469	26,602	100,638	176,426	235,527	235,403	235,188	234,405	233,545	232,855
Tax Depreciation	0	0	0	0	0	0	0	2,977,555	2,997,822	3,003,982	3,011,412	3,022,558	3,044,848
CPI	1,641,273	1,677,839	1,728,447	1,775,678	1,835,212	938,317	2,538	7	0	0	0	0	0
Manufacturer Prod Deduct	88,379	69,615	71,820	77,629	77,055	83,170	57,270	(46,510)	(43,244)	(43,728)	(43,216)	(41,681)	(43,129)
Removal of Old Plant	472,469	897,945	922,425	868,458	962,398	959,998	1,570,070	1,804,970	1,721,370	1,723,870	1,696,370	1,643,870	1,641,370

	TY HB ND				ALT HB ND		Adjusted ND
	BOY	EOY	Average	ND Only	ND Only	ND Only	
Rate Base							
Plus Plant In-Service	0	369,508,709	184,754,355	9,020,119	2,267,878	6,752,241	
Less Book Depreciation Reserve	0	6,363,101	3,181,550	155,330	94,495	60,835	
Less Accum Deferred Taxes	(3,198,556)	6,934,907	1,868,175	91,208	7,719	83,489	
End Of Month Rate Base	3,198,556	356,210,701	179,704,629	8,773,580	2,165,664	6,607,916	
Average Rate Base (BOY/EOY)	2008 Annual	ND Only	Alt Plan ND	Adjustment ND			
	179,704,629	8,773,580	2,165,664	6,607,916			
Calculation of Return							
Plus Debt Return	6,020,105	293,915	72,550	221,365			
Plus Equity Return	9,578,257	467,632	115,430	352,202			
Total Return	15,598,362	761,547	187,980	573,567			
Income Statement Items							
Plus Book Depreciation	6,363,101	310,661	188,990	121,671			
Plus Deferred Taxes	10,133,463	494,738	15,438	479,300			
Plus Current Taxes	(395,951)	(19,331)	53,412	(72,743)			
Total Income Statement Expense	16,100,613	786,068	257,840	528,228			
Total Revenue Requirements	31,698,974	1,547,614	445,820	1,101,795			
Interchange Demand	84.4383%						
Jurisdiction Demand	5.7820%						
Interchange Composite Allocator	4.8822%						
Jurisdictional Revenue Requirement	1,547,614						

See HB Alt tab for details

Tax Depreciation	18,058,177
CPI	7,958,038
Manufacturer Prod Deduct	175,052
Removal of Old Plant	16,413,114
State of ND Composite Tax Rate	39.225%

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

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

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

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

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

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
RATE BASE SCHEDULES
RATE BASE ADJUSTMENT SCHEDULES
2008 Unadjusted Test Year versus 2008 Adjusted Test Year
(\$000's)

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

<u>Line No.</u>	<u>Description</u>	<u>Initial Petition</u> (1)	<u>Income Statement</u> (2)	<u>Rebuttal Position</u> (3)
	Electric Plant as Booked			
1	Production	\$356,704		\$356,704
2	Transmission	\$87,557		\$87,557
3	Distribution	\$124,202		\$124,202
4	General	\$14,538		\$14,538
5	Common	\$24,338		\$24,338
6	TBT Investment	\$0		\$0
7	TOTAL Utility Plant in Service	\$607,339		\$607,339
	Reserve for Depreciation			
8	Production	\$234,339		\$234,339
9	Transmission	\$29,941		\$29,941
10	Distribution	\$48,239		\$48,239
11	General	\$6,955		\$6,955
12	Common	\$13,692		\$13,692
13	TOTAL Reserve for Depreciation	\$333,166		\$333,166
	Net Utility Plant in Service			
14	Production	\$122,365		\$122,365
15	Transmission	\$57,616		\$57,616
16	Distribution	\$75,964		\$75,964
17	General	\$7,583		\$7,583
18	Common	\$10,646		\$10,646
19	TBT Investment	\$0		\$0
20	Net Utility Plant in Service	\$274,173		\$274,173
21	Utility Plant Held for Future Use	\$0		\$0
22	Construction Work in Progress	\$4,802		\$4,802
23	Less: Accumulated Deferred Income Taxes	\$40,717		\$40,717
24	Cash Working Capital	\$1,136	\$8	1,144
	Other Rate Base Items:			
25	Materials and Supplies	\$5,412		\$5,412
26	Fuel Inventory	\$2,358		\$2,358
27	Non-Plant Assets & Liabilities	(\$6,928)		(\$6,928)
28	Prepayments	\$1,127		\$1,127
32	Customer Advances	(\$60)		(\$60)
33	Other Working Capital	\$797		\$797
34	Total Other Rate Base Items	\$2,706	\$0	\$2,706
35	Total Average Rate Base	\$242,100	\$8	\$242,108

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

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

OPERATING INCOME STATEMENT SCHEDULES
 OPERATING INCOME STATEMENT ADJUSTMENT SCHEDULES
 2008 Unadjusted Test Year versus 2008 Adjusted Test Year
 (\$000's)

Line No.	Description	Initial Petition	MISO Sch 16 & 17 Margin Adj 1	Nuclear Refueling Outage Change of Accounting 2	Allen S King Chemical Cost Correction 3	Cost of Debt 4	CWC 5	Rebuttal Position (1)
Operating Revenues								
1	Retail	\$147,179	\$532					\$147,711
2	CIP Revenue Adjustment	0						\$0
3	Interdepartmental	0						\$0
4	Other Operating	39,525						\$39,525
5	Gross Earnings Tax	0						\$0
6	Total Operating Revenues	\$186,704	\$532	\$0	\$0	\$0	\$0	\$187,236
Expenses								
Operating Expenses:								
7	Fuel & Purchased Energy	\$79,015						\$79,015
8	Power Production	40,491		(173)	(322)			\$39,996
9	Transmission	7,992						\$7,992
10	Distribution	5,655						\$5,655
11	Customer Accounting	4,343						\$4,343
12	Customer Service & Information	369						\$369
13	Sales, Econ Dvlp & Other	2						\$2
14	Administrative & General	10,399						\$10,399
15	Amortization	460						\$460
16	Total Operating Expenses	\$148,725	\$0	(\$173)	(\$322)	\$0	\$0	\$148,230
17	Depreciation	\$19,160						\$19,160
Taxes:								
18	Property	\$5,763						\$5,763
19	Gross Earnings	0						\$0
20	Deferred Income Tax & ITC	1,738						\$1,738
21	Federal & State Income Tax	214	209	68	126	19	(0)	\$636
22	Payroll & Other	1,310						\$1,310
23	Total Taxes	\$9,025	\$209	\$68	\$126	\$19	(\$0)	\$9,447
24	Total Expenses	\$176,910	\$209	(\$105)	(\$195)	\$19	(\$0)	\$176,837
25	Allowance for Funds Used During Construction	\$0				\$0	\$0	\$0
26	Total Operating Income	\$9,794	\$323	\$105	\$195	(\$19)	\$0	\$10,399

Note: (1) Electric Utility - North Dakota Jurisdiction

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

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

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

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

Case No. PU-07-776
Exhibit ____ (AEH-2)
Schedule 7, Page 1 of 6

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

Summary Reports

June 13, 2008

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

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

(Dollars in Thousands)

Rate Base Summary

	Total Company Electric			North Dakota Retail Electric			All Other		
	<u>Beginning Balance</u>	<u>Ending Balance</u>	<u>Average Balance</u>	<u>Beginning Balance</u>	<u>Ending Balance</u>	<u>Average Balance</u>	<u>Beginning Balance</u>	<u>Ending Balance</u>	<u>Average Balance</u>
1 Plant Investment	10,486,491	11,699,172	11,092,832	572,054	642,623	607,339	9,914,437	11,056,549	10,485,493
2 Depreciation Reserve	<u>(5,821,431)</u>	<u>(6,216,224)</u>	<u>(6,018,828)</u>	<u>(322,262)</u>	<u>(344,069)</u>	<u>(333,166)</u>	<u>(5,499,169)</u>	<u>(5,872,155)</u>	<u>(5,685,662)</u>
3 Net Utility Plant	4,665,060	5,482,948	5,074,004	249,792	298,554	274,173	4,415,268	5,184,394	4,799,831
4 C.W.I.P.	471,316	244,824	358,070	5,117	4,487	4,802	466,199	240,338	353,268
5 Accumulated Deferred Taxes	(759,615)	(788,332)	(773,974)	(39,716)	(41,717)	(40,717)	(719,899)	(746,615)	(733,257)
Other Rate Base:									
6 Cash Working Capital	12,347	12,347	12,347	1,144	1,144	1,144	11,202	11,202	11,202
7 Materials & Supplies	92,681	92,681	92,681	5,412	5,412	5,412	87,269	87,269	87,269
8 Fuel Inventory	40,111	40,111	40,111	2,358	2,358	2,358	37,753	37,753	37,753
9 Non-Plant Assets & Liab	(115,650)	(118,027)	(116,839)	(6,856)	(6,999)	(6,928)	(108,794)	(111,028)	(109,911)
10 Prepays & Other	30,355	30,355	30,355	1,864	1,864	1,864	28,491	28,491	28,491
11 Total Rate Base	4,436,604	4,996,907	4,716,755	219,115	265,103	242,108	4,217,489	4,731,804	4,474,646

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

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

(Dollars in Thousands)

Income Statement Summary

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>	
<u>Operating Revenues</u>				
1	Retail	2,877,113	147,711	2,729,402
2	CIP Adjustment to Program Costs	0	0	0
3	Interdepartmental	434	0	434
4	Other Operating	725,631	39,525	686,106
5	Gross Earnings Tax	0	0	0
6	Total Operating Revenues	3,603,178	187,236	3,415,942
<u>Expenses</u>				
Operating Expenses:				
7	Fuel & Purchased Energy	1,344,010	79,015	1,264,995
8	Power Production	686,183	39,996	646,186
9	Transmission	138,216	7,992	130,224
10	Distribution	110,071	5,655	104,416
11	Customer Accounting	59,420	4,343	55,077
12	Customer Service & Information	60,501	369	60,133
13	Sales, Econ Dvlp & Other	138	2	136
14	Administrative & General	161,492	10,399	151,093
15	Total Operating Expenses	2,560,030	147,770	2,412,260
16	Depreciation	365,768	19,160	346,608
17	Amortization	27,513	460	27,053
Taxes:				
18	Property	105,494	5,763	99,731
19	Gross Earnings	0	0	0
20	Deferred Income Tax & ITC	64,161	1,738	62,423
21	State & Federal Income (see Page 3)	86,603	636	85,967
22	Payroll & Other	21,401	1,310	20,091
23	Total Taxes	277,659	9,447	268,212
24	Total Expenses	3,230,970	176,837	3,054,133
25	AFUDC	0	0	0
26	Total Operating Income	372,208	10,399	361,809

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

(Dollars in Thousands)

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

Income Tax Summary

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>	
<u>Income Before Taxes</u>				
1	Total Operating Revenues	3,603,178	187,236	3,415,942
2	less: Total Operating Expenses	(2,560,030)	(147,770)	(2,412,260)
3	Book Depreciation & Amortization	(393,281)	(19,620)	(373,661)
4	Taxes (Other Than Current Income)	(191,056)	(8,811)	(182,245)
5	Total Before Tax Book Income	458,811	11,035	447,776
<u>Tax Additions</u>				
6	Book Depreciation	365,768	19,160	346,608
7	Nuclear Fuel Book Burn	69,384	4,012	65,372
8	Nuclear Fuel Disposal	12,473	721	11,752
9	Book Depreciation Cleared To Operating	0	0	0
10	Deferred Income Taxes & ITC	64,161	1,738	62,423
11	Book Amortizations	0	0	0
12	Connection Fees	0	0	0
13	Avoided Tax Interest	59,766	3,412	56,354
14	Tax Capitalized Leases	0	0	0
15	Meals & Entertainment	528	32	496
16	TBT Net Expense	0	0	0
17	Total Tax Additions	572,080	29,075	543,005
<u>Tax Deductions</u>				
18	Tax Depreciation & Removal Expense	665,489	30,605	634,884
19	Debt Interest Expense	152,351	7,820	144,531
20	Man Prod Ded / Prod Tax Credit	5,093	310	4,783
21	Other Tax/Book Timing Differences	(4,082)	(246)	(3,836)
22	Net Preferred Stock Deduction	0	0	0
23	Total Tax Deductions	818,851	38,489	775,579
24	State Taxable Income	212,040	1,621	210,419
25	State Income Tax Rate	8.99%	6.51%	N/A
26	Total State Income Taxes	19,060	106	18,955
27	Federal Taxable Income	192,979	1,516	191,464
28	Federal Income Tax Rate	35.00%	35.00%	35.00%
29	Total Federal Income Taxes	67,543	530	67,012
30	Total Federal & State Income Taxes	86,603	636	85,967

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

Case No. PU-07-776
 Exhibit ___ (AEH-2)
 Schedule 7, Page 5 of 6

Revenue Requirement & Return Summary

(Dollars in Thousands)

	<u>Capital Structure</u>	<u>Rate</u>	<u>Ratio</u>	<u>Weighted Cost</u>	<u>Composite Income Tax Rates</u>	
1	Long Term Debt	6.7600%	45.6100%	3.0800%	State of North Dakota Tax rate	6.50%
2	Short Term Debt	5.7400%	2.6200%	0.1500%	Federal Statutory Tax rate	35.00%
3	Preferred Stock	0.0000%	0.0000%	0.0000%	Federal Effective Tax Rate (1-State Rate * Fed Rate)	32.73%
4	Common Equity	10.7500%	51.7700%	5.5700%	Total North Dakota Composite Tax Rate	39.23%
5	Required Rate of Return			8.8000%	Total Corporate Composite Tax Rate	40.84%

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>	
<u>Rate of Return (ROR)</u>				
6	Total Operating Income	372,208	10,399	361,809
7	Total Average Rate Base	4,716,755	242,108	4,474,646
8	ROR (Operating Income / Rate Base)	7.89%	4.30%	8.09%
<u>Return on Equity (ROE)</u>				
9	Total Operating Income	372,208	10,399	361,809
10	Debt Interest (Rate Base * Weighted Debt Cost)	(152,351)	(7,820)	(144,531)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	219,857	2,579	217,278
13	Equity Rate Base (Rate Base * Equity Ratio)	2,441,864	125,339	2,316,524
14	ROE (Earnings for Common / Equity Rate Base)	9.00%	2.06%	9.38%
<u>Revenue Deficiency</u>				
15	Require Operating Income (Rate Base * Required Return)	415,074	21,306	393,769
16	Operating Income	372,208	10,399	361,809
17	Operating Income Deficiency	42,867	10,906	31,960
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.69041	1.64555	N/A
19	Revenue Deficiency (Income Deficiency * Conversion Fac	72,463	17,946	54,517
<u>Total Retail Revenue Requirements</u>				
20	Retail Related Revenues	2,877,547	147,711	2,729,836
21	Revenue Deficiency	72,463	17,946	54,517
22	Total Retail Revenue Requirements	2,950,010	165,657	2,784,353
23	<u>Percentage Increase (Decrease)</u>	2.52%	12.15%	2.00%

(Dollars in Thousands)

Rate Base Detail - Cash Working Capital

		Total Company Electric		ND Retail Electric		All Other				
<u>Expenses</u>										
<u>Includable Expenses</u>	<u>Lead Days</u>	<u>Dollars</u>	<u>Dollar x Days</u>	<u>Dollars</u>	<u>Dollar x Days</u>	<u>Dollars</u>	<u>Dollar x Days</u>			
<u>Fuel Expenses</u>										
1	Coal & Rail Transport	24.78	367,060	9,095,753	21,579	534,739	345,481	8,561,014		
2	Gas for Generation	41.90	139,412	5,841,374	8,196	343,414	131,216	5,497,960		
3	Oil	14.13	7,092	100,215	417	5,892	6,675	94,324		
4	Nuclear & EOL	0.00	80,062	0	4,707	0	75,355	0		
5	Nuclear Disposal	76.38	12,473	952,688	721	55,070	11,752	897,618		
6			606,100	15,990,030	35,620	939,115	570,480	15,050,915		
<u>Purchased Power</u>										
7	Purchases	24.62	989,971	24,373,094	57,960	1,426,977	932,011	22,946,117		
8	Interchange	38.21	103,226	3,944,260	5,991	228,902	97,235	3,715,358		
			1,093,197	28,317,353	63,951	1,655,879	1,029,246	26,661,475		
<u>Labor & Related Costs</u>										
9	Regular Payroll	12.82	244,810	3,138,461	14,763	189,258	230,047	2,949,204		
10	Incentive Compensation	255.13	11,547	2,945,961	693	174,224	10,864	2,771,736		
11	Pension & Benefits	28.34	41,928	1,188,248	2,613	74,046	39,316	1,114,202		
12	Subtotal Labor & Related		298,285	7,272,670	18,058	437,528	280,227	6,835,142		
14	All Other Operating Expenses	42.34	562,448	23,814,050	30,140	1,276,143	532,308	22,537,907		
15	Property Tax	353.01	105,494	37,240,437	5,763	2,034,397	99,731	35,206,040		
16	Employer's Payroll Taxes	26.83	21,401	574,194	1,310	35,149	20,091	539,045		
17	Gross Earnings Tax	55.01	39,086	2,150,121	2,081	114,476	37,005	2,035,645		
18	Federal Income Tax	36.50	67,543	2,465,311	530	19,363	67,012	2,445,948		
19	State Income Tax	36.50	19,060	695,705	106	3,851	18,955	691,854		
20	State Sales Tax Customer Billings	51.86	110,642	5,737,894	0	0	110,642	5,737,894		
21	Total Expenses	42.51	2,923,257	124,257,766	41.36	157,560	6,515,901	42.57	2,765,697	117,741,865
22	Net Annual Expense Amount			340,432			17,852			322,580
<u>Revenues</u>										
23	Computer Billing	100.00%	45.45	2,879,484	130,872,548	149,550	6,797,048	2,729,934	124,075,500	
24	Hand Billed	0.00%	45.45	0	0	0	0	0	0	
25	Retail Revenue Adjustments	45.45	(2,371)	(107,762)	(1,839)	(83,583)	(532)	(24,179)		
26	Interdepartmental	0.00	434	0	0	0	434	0		
27	Late Payment	0.00	7,252	0	245	0	7,007	0		
28	Connect and Trouble Charges	45.45	2,217	100,763	173	7,863	2,044	92,900		
29	CIP Incentive	0.00	0	0	0	0	0	0		
30	Rentals	34.28	4,630	158,716	251	8,604	4,379	150,112		
31	Interchange Revenues	38.21	388,380	14,840,000	22,648	865,380	365,732	13,974,620		
32	Sales for Resale	39.63	255,111	10,110,049	12,380	490,619	242,731	9,619,430		
33	Production Associated Revenues	39.63	6,382	252,919	375	14,861	6,007	238,057		
34	MISO	39.63	36,762	1,456,878	2,125	84,214	34,637	1,372,664		
35	Point to Point Firm	39.63	4,680	185,468	271	10,740	4,409	174,729		
36	Services & Facilities	39.63	8,621	341,650	493	19,538	8,128	322,113		
37	Ancillary	39.63	6,223	246,617	360	14,267	5,863	232,351		
38	Distribution Associated Revenues	45.45	1,986	90,264	0	0	1,986	90,264		
39	Other	45.45	5,367	243,930	320	14,544	5,047	229,386		
40	JOA - Rev fr/to PSC	39.63	(1,980)	(78,467)	(116)	(4,597)	(1,864)	(73,870)		
41	(blank)	0.00	0	0	0	0	0	0		
42	(blank)	0.00	0	0	0	0	0	0		
43	(blank)	0.00	0	0	0	0	0	0		
44	Total Revenues	44.05	3,603,178	158,713,573	44.01	187,236	8,239,498	44.05	3,415,942	150,474,075
45	Net Annual Amount			434,832			22,574			412,258
46	Expense / Revenue Factor			0.81129951			0.841503833			
47	Allocated Revenue Amount			352,779			18,996			
48	Net Cash Working Capital	Page 1 - Line 6		12,347			1,144			11,202

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

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

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

Northern States Power Company, a Minnesota Corporation
 Electric Utility - State of North Dakota
 Rate Base Schedules
 Rate Base Adjustment Schedules
 2008 Unadjusted Test Year versus 2008 Recalculated Staff Position
 (\$000's)

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

Line No.	Description	Initial Petition Rate Base (A)	Reverse Pole Inspection & Replacement Program RB-1	Reverse Cable Replacement Program RB-2	Charge Pole & Cable Replacements to Acc. Dep. RB-3	Adjust Cash Working Capital RB-4	King's Depreciation Rate Adjustment RB-7	Amortize Cost of Removal Over 10 years RB-8	Corrected Staff Adjusted
1	Electric Plant as Booked								
2	Production	\$356,704							\$356,704
3	Transmission	\$87,557							\$87,557
4	Distribution	\$124,202	(\$92)	(\$250)	\$0			\$0	\$123,860
5	General	\$14,538							\$14,538
6	Common	\$24,338							\$24,338
7	TBT Investment	\$0							\$0
7	TOTAL Utility Plant in Service	\$607,339	(\$92)	(\$250)	\$0	\$0	\$0	\$0	\$606,997
8	Reserve for Depreciation								
9	Production	\$234,339					(\$1,830)	(\$919)	\$231,591
10	Transmission	\$29,941					(\$37)		\$29,904
11	Distribution	\$48,239	(\$2)	(\$3)	(\$342)		(\$191)		\$47,701
12	General	\$6,955							\$6,955
13	Common	\$13,692							\$13,692
13	TOTAL Reserve for Depreciation	\$333,166	(\$2)	(\$3)	(\$342)	\$0	(\$2,058)	(\$919)	\$329,843
14	Net Utility Plant in Service								
15	Production	\$122,365	\$0	\$0	\$0	\$0	\$1,830	\$919	\$125,113
16	Transmission	\$57,616	\$0	\$0	\$0	\$0	\$37	\$0	\$57,653
17	Distribution	\$75,964	(\$91)	(\$247)	\$342	\$0	\$191	\$0	\$76,159
18	General	\$7,583	\$0	\$0	\$0	\$0	\$0	\$0	\$7,583
19	Common	\$10,646	\$0	\$0	\$0	\$0	\$0	\$0	\$10,646
20	TBT Investment	\$0							\$0
20	Net Utility Plant in Service	\$274,173	(\$91)	(\$247)	\$342	\$0	\$2,058	\$919	\$277,154
21	Utility Plant Held for Future Use	\$0							\$0
22	Construction Work in Progress	\$4,802							\$4,802
23	Less: Accumulated Deferred Income Taxes	\$40,717	(\$1)	(\$3)			\$807	\$360	\$41,881
24	Cash Working Capital	\$1,136							\$1,136
25	Other Rate Base Items:								
26	Materials and Supplies	\$5,412							\$5,412
27	Fuel Inventory	\$2,358							\$2,358
28	Non-Plant Assets & Liabilities	(\$6,928)							(\$6,928)
29	Prepayments	\$1,127							\$1,127
30	Customer Advances	(\$60)							(\$60)
30	Other Working Capital	\$797							\$797
31	Total Other Rate Base Items	\$2,706	\$0	\$0	\$0	\$0	\$0	\$0	\$2,706
32	Total Average Rate Base	\$242,100	(\$90)	(\$244)	\$342	\$0	\$1,251	\$558	\$243,917

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

Case No. PU-07-776
 Exhibit ___ (AEH-2)
 Schedule 8, 3 of 5

OPERATING INCOME STATEMENT SCHEDULES
 OPERATING INCOME STATEMENT ADJUSTMENT SCHEDULES
 2008 Unadjusted Test Year versus 2008 Adjusted Test Year
 (\$000's)

Line No.	Description	Initial Petition Income Stmt	Settlement ROR Change OI-1	Reverse Asset Based Trading-Ratepayer sharing OI-2	Reverse Asset Based Trading-Shareholder sharing OI-3	Reverse Non-Asset Based Trading-Ratepayer sharing OI-4	Reverse Non-Asset Based Trading-Shareholder sharing OI-5
Operating Revenues							
1	Retail	\$147,179		\$0		\$0	
2	CIP Revenue Adjustment	0					
3	Interdepartmental	0					
4	Other Operating	39,525			\$0		\$0
5	Gross Earnings Tax	0					
6	Total Operating Revenues	\$186,704	\$0	\$0	\$0	\$0	\$0
Expenses							
Operating Expenses:							
7	Fuel & Purchased Energy	\$79,015					
8	Power Production	40,491					
9	Transmission	7,992					
10	Distribution	5,655					
11	Customer Accounting	4,343					
12	Customer Service & Information	369					
13	Sales, Econ Dvlp & Other	2					
14	Administrative & General	10,399					
15	Amortization	460					
16	Total Operating Expenses	\$148,726	\$0	\$0	\$0	\$0	\$0
17	Depreciation	\$19,160					
Taxes:							
18	Property	\$5,763					
19	Gross Earnings	0					
20	Deferred Income Tax & ITC	1,738					
21	Federal & State Income Tax	214	0	0	0	0	0
22	Payroll & Other	1,310					
23	Total Taxes	\$9,025	\$0	\$0	\$0	\$0	\$0
24	Total Expenses	\$176,910	(\$1)	(\$1)	(\$1)	(\$1)	(\$1)
25	Allowance for Funds Used During Construction	\$0					
26	Total Operating Income	\$9,794	\$1	\$1	\$1	\$1	\$1

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

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

OPERATING INCOME STATEMENT SCHEDULES
 OPERATING INCOME STATEMENT ADJUSTMENT SCHEDULE
 2008 Unadjusted Test Year versus 2008 Adjusted Test Year
 (\$000's)

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

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

OPERATING INCOME STATEMENT SCHEDULES
 OPERATING INCOME STATEMENT ADJUSTMENT SCHEDULE
 2008 Unadjusted Test Year versus 2008 Adjusted Test Year
 (\$000's)

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

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

A S King Plant Chemical Cost Adjustment

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

Xcel Energy
2008 Budget Allocations

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

Before the North Dakota Public Service Commission
State of North Dakota

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

For Authority to Increase Rates for
Electric Service in North Dakota

Case No. PU-07-776
Exhibit ____

Interruptible Rates

June 13, 2008

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II.	Discussion	2
III.	Conclusions	6

1 **I. INTRODUCTION**

2
3 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

4 A. My name is Phillip J. Zins. My business address is 414 Nicollet Mall,
5 Minneapolis, Minnesota, 55401.

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 (“Xcel Energy” or the “Company”) a Minnesota corporation operating in
10 North Dakota.

11
12 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

13 A. The purpose of my Rebuttal Testimony is to respond to the North Dakota
14 Public Service Commission’s (the “Commission”) request that Parties address
15 specific questions it raised regarding the Company’s existing interruptible rate
16 tariffs given the Company’s recent exit from the Mid-Continent Area Power
17 Pool (“MAPP”).

18
19 The Company officially withdrew from MAPP on June 1, 2008 and is now a
20 member of the Midwest Planning Reserve Sharing Group (“MPRSG”) and the
21 Midwest Reliability Organization (“MRO”). The Commission’s questions
22 concerning these events were expressed in its February 28, 2008 letter to the
23 Parties in this proceeding. For convenient reference, I have provided a copy
24 of this letter as Exhibit___(PJZ-2), Schedule 1.

25
26 In this letter, the Commission also articulated questions concerning the
27 appropriate retail rate-recovery of administrative costs associated with

1 Midwest Independent System Operator (“MISO”). This second question is
2 addressed by Mr. Stephen J. Beuning in his Direct Testimony and Ms. Anne
3 E. Heuer in her Rebuttal Testimony.

4 5 **II. DISCUSSION**

6
7 Q. MR. ZINS, PLEASE DESCRIBE THE CONCERNS EXPRESSED BY THE COMMISSION
8 REGARDING THE POTENTIAL IMPACTS ON INTERRUPTIBLE RATES RESULTING
9 FROM THE COMPANY’S EXIT FROM MAPP AND MEMBERSHIP IN THE MPRSG
10 AND MRO.

11 A. The Commission asks; *“whether the terms and conditions and enforcement provisions for*
12 *interruptible service are cost based and reasonable given the changes occurring in the wholesale*
13 *industry.”* The Commission appears to be concerned that the Company’s
14 withdrawal from MAPP may have altered the fundamental resource planning
15 value of the Company’s retail interruptible rate programs. Additionally, the
16 Commission’s letter seems to be asking whether the Company’s membership
17 in the MPRSG and MRO requires changes to the design of our interruptible
18 rate tariffs. Finally, the Commission wishes to know whether any provisions
19 of MISO’s wholesale tariffs require changes to the Company’s interruptible
20 tariffs.

21
22 Q. HAS THE FUNDAMENTAL RESOURCE PLANNING VALUE OF THE COMPANY’S
23 INTERRUPTIBLE RATES BEEN ALTERED BY THE COMPANY’S WITHDRAWAL FROM
24 MAPP?

25 A. No. The Company’s membership in the MPRSG and MRO results in
26 generation planning reserve requirements that are very similar to that of

1 MAPP.¹ That is, the Company will still be required to maintain adequate
2 generation planning reserves and its interruptible rate programs will continue
3 to be valuable in helping manage load to help assure that the generation
4 planning reserve requirement is achieved.

5
6 In summary, the fundamental resource planning value of the Company's
7 interruptible rate programs are not altered by the Company's exit from MAPP
8 and the replacement membership in the MPRSG and MRO.

9
10 Q. DOES THE COMPANY'S WITHDRAWAL FROM MAPP AND MEMBERSHIP IN THE
11 MPRSG AND MRO REQUIRE CHANGES TO THE DESIGN OF THE
12 INTERRUPTIBLE TARIFFS?

13 A. No. As indicated above, the planning reserve requirements under the MPRSG
14 are not conceptually different from those that existed under MAPP. Both
15 MAPP and MPRSG/MRO generation planning reserve requirements are
16 designed to assure that each utility (and the system as a whole) has enough
17 generation capacity to meet expected peak loads plus sufficient reserves to
18 cover unexpected events, such as load levels being greater than forecast
19 and/or generation plant outages.

20
21 MAPP accomplished this by requiring the utility to have certified generation
22 capacity equal to at least 115% of its actual system peak load, measured after
23 the fact (in other words, based on actual historical peak demand rather than a
24 forecasted load). Under this system, the Company used its interruptible load
25 to reduce its system peak load to assure that after the actual peak load had

¹ The generation planning reserve requirement of MPRSG and MRO replace that of MAPP.

1 occurred there was still at least 15% generation capacity in reserve. This
2 method used by MAPP resulted in sufficient reserve margin to permit
3 participants to take “credit” for plants that may have failed or that were out of
4 service for maintenance.

5
6 Under the MPRSG, the planning reserve requirement is conceptually the same
7 but somewhat different in administration. The MPRSG requires participants
8 to have available generation capacity, equal to at least 114.2% of their
9 forecasted load. However, the generation resources used to meet this
10 requirement must be those actually available to meet load and would not
11 include resources that are down for scheduled maintenance or those forced
12 out of service. The practical impact of this difference in the respective
13 requirements on the amount of planning reserves each utility maintains will
14 likely be small. But any case, the difference does not affect the conceptual
15 basis for the Company’s interruptible rate programs.

16
17 Thus, the basic economics that guide the design of the interruptible tariffs (e.g.
18 interruption credits and associated terms, conditions of service) remain the
19 same under the MPRSG planning reserve requirements as they were under
20 MAPP. The interruptible rate credits along with the interruption-performance
21 requirements specified in the terms and conditions must: (1) be attractive
22 enough to incent customers to voluntarily sell-back to the Company some of
23 their entitlement to firm service; but also (2) provide the utility (and its
24 customers) with an alternative source of peaking capacity, which has cost
25

1 and performance characteristics, that are comparable to and competitive with,
2 building and owning combustion turbine capacity or purchasing capacity from
3 other power suppliers in the wholesale market.

4
5 Q. MR. ZINS CAN YOU RESPOND TO THE QUESTION OF WHETHER THE COMPANY'S
6 INTERRUPTIBLE RATES REMAIN "COST BASED AND REASONABLE" UNDER THE
7 MPRSG AS COMPARED TO MAPP?

8 A Yes, this question is really a sub-part of the previous question. As indicated in
9 my Direct Testimony, the economic essence of a utility's "obligation to serve"
10 is to provide low-cost reliable firm service. This means that "interruptible
11 service" is in reality, firm utility service, attached to which is an after-the-fact
12 power supply contract, through which the utility has the opportunity to buy-
13 back from willing customers a part of their firm utility service.

14
15 The result is a peaking capacity purchase transaction that occurs when, and if,
16 doing so is consistent with the utility's obligation to provide low-cost reliable
17 firm service to all customers collectively. This interruptible-rate source of
18 peaking capacity (and the necessary detailed terms, conditions and design of
19 the interruptible tariffs) continue to be designed to be competitive with
20 supply-side sources such as building and owning combustion turbine capacity
21 or purchasing peaking capacity from another wholesale power supplier

22
23 In summary, the historic "economic calculus" that underlies the design of the
24 Company's interruptible rate tariffs is reasonable and remains the same as it
25 was under MAPP.

26

1 Q. DO ANY OF SPECIFIC PROVISIONS OF MISO WHOLESale TARIFFS, AS
2 COMPARED TO THOSE UNDER MAPP, HAVE AN IMPACT ON THE TERMS,
3 CONDITIONS OR DESIGN OF THE COMPANY'S INTERRUPTIBLE RATES?

4 A. I am not aware of any MISO tariff provisions that would justify changing the
5 design or administration of the Company's interruptible rate programs. The
6 proposed revisions to MISO Module E relating to Resource Adequacy are not
7 expected to be final until the spring of 2009 at the earliest and it remains to be
8 seen if the MISO Module E changes will affect our Resource Adequacy
9 considerations. In the meantime, we continue operate under the MPRSG for
10 Resource Adequacy purposes.

11
12 It is possible that, as the MISO wholesale market matures, new opportunities
13 may develop through which the Company could propose revisions to its
14 interruptible tariffs to derive additional benefits for the system. However, at
15 this point the Company has no reason to modify its interruptible tariffs or
16 change the way they are administered as a result of MISO wholesale tariff
17 provisions.

18
19 **III. CONCLUSIONS**

20
21 Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

22 A. The Company's interruptible rate programs are designed to be competitive
23 with conventional alternative sources of peaking capacity and continue be
24 valuable in light of the Company's exit from MAPP and membership in the
25 MPRSG and MRO. At the present time, there are no changes in the terms,
26 conditions or the design of the Company's interruptible rate programs, which
27

1 are warranted by either the switch from MAPP to MPRSG generation
2 planning reserve requirements or from MISO wholesale market tariffs.

3

4 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

5 A. Yes, it does.

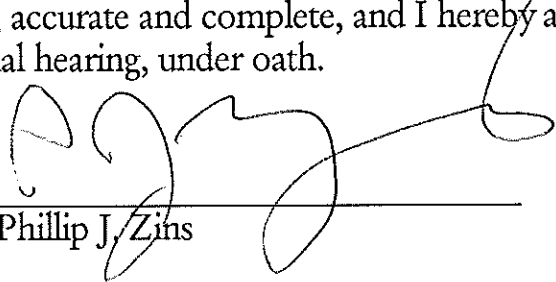
1 STATE OF NORTH DAKOTA
2 BEFORE THE
3 PUBLIC SERVICE COMMISSION
4

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)
9 in North Dakota)

Case No. PU-07-776

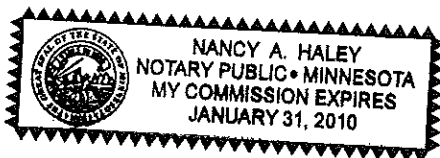
10
11
12
13 AFFIDAVIT OF
14 Phillip J. Zins
15
16

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 Phillip J. Zins
27
28
29

30 Subscribed and sworn to before me, this 12 day of June, 2008.
31

32
33 
34 Notary Public
35
36





Public Service Commission
State of North Dakota

Case No. PU-07-776
Exhibit____(PJZ-2)
Schedule 1
Page 1 of 2

COMMISSIONERS

Susan E. Wefald, President
Kevin Cramer
Tony Clark

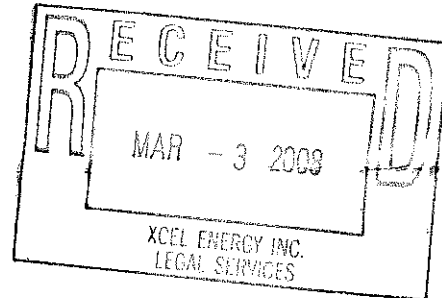
Executive Director
Ilona A. Jeffcoat-Sacco

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February 28, 2008

Megan J. Hertzler
Assistant General Counsel
Xcel Energy Services Inc.
414 Nicollet Mall, 5th Fl.
Minneapolis, MN 55401

Douglas A. Bahr
Division Director
Office of the Attorney General
600 E. Boulevard Ave. Dept 125
Bismarck, ND 58505



Re: Case No. PU-07-776, NSP Electric Rate Increase Application

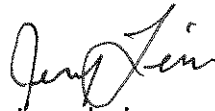
Dear Ms. Hertzler and Mr. Bahr:

The purpose of this letter is to request that you investigate and address the following issues:

1. Whether the terms, conditions and enforcement provisions for interruptible services are cost based and reasonable especially given changes occurring in the wholesale industry, including the expected discontinuance of the Mid-continent Area Power Pool financial obligation for planning reserve capacity and implementation of the Midwest ISO markets and Open Access Transmission Tariff (OATT) Module E resource adequacy requirements.
2. What recovery procedures should be approved for Midwest ISO energy market costs and should any amounts already recovered be refunded? Interim procedures for recovery through NSP's Fuel Cost Adjustment were approved subject to refund by the Commission in Case No. PU-05-147. Since then, the FERC ordered that MISO administrative cost adders under OATT schedules 16 and 17 are no longer eligible for recording as a cost of fuel and purchased energy in FERC Account 555. MDU (Case No. PU-06-447) and Otter Tail (Case

No. PU-05-131) have refunded schedule 16 and 17 administrative charges and are no longer recovering those costs through fuel cost adjustments.

Sincerely,



Jerry Lein
Public Utilities Analyst
Commission Advisory Staff

cc Kent Larson
Dave Sederquist
Mike Diller
Pat Fahn
Commissioner Susan Wefald
Commissioner Kevin Cramer
Commissioner Tony Clark