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June 16, 2008

Illona A. Jeffcoat-Sacco, Executive Director
North Dakota Public Service Commission
State Capitol Building, Dept 408
600 East Boulevard
Bismarck, ND 58505-0480

VIA ELECTRONIC FILING AND U.S. MAIL

Re: *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

Dear Ms. Jeffcoat-Sacco:

In follow up to our June 13, 2008 letter and pursuant to North Dakota Century Code, Section 49-05-05, Northern States Power Company, a Minnesota corporation operating in North Dakota, submits an original and ten (10) copies of Rebuttal Testimony of the following witnesses in the above-referenced proceeding:

- *Elizabeth M. Engelking*- Generation Investments and Resource Planning
- *Richard A. Rosvold*- Environmental Issues and Investments

This completes our Rebuttal Testimony submission. We have served copies of this filing on all parties on the attached service list. Please contact me at (701) 241-8632 if you have any questions regarding this filing.

Sincerely,

David H. Sederquist

David H. Sederquist
Sr. Consultant, Regulation & Finance
Northern States Power Company,
a Minnesota corporation operating in North Dakota

Enclosures

cc: Service list

In the Matter of the Application by
Northern States Power Company,
a Minnesota corporation
for Authority to Increase Rates for Electric Service in North Dakota
Case No. PU-07-776
OAH File No. 20080012

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Rebuttal Testimony and Schedule
Elizabeth M. Engelking

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___

Generation Investments and Resource Planning

June 13, 2008

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Elizabeth Engelking. I am Manager of Resource Planning and Bidding for Northern States Power Company, a Minnesota corporation operating in North Dakota ("Xcel Energy" or the "Company"). My business address is 414 Nicollet Mall (MP7), Minneapolis, Minnesota 55401-1993.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I received my MBA in finance and economics from the University of Minnesota (Carlson School of Management) in 1986. From 1988-1998, I was employed as a rate analyst with the Minnesota Public Utilities Commission ("MPUC"), where I oversaw the implementation of Integrated Resource Planning and advised the MPUC on utility resource planning, ratemaking, and industry restructuring issues. Following my tenure at the MPUC, I joined Great River Energy in 1998, first as a transmission analyst and then, in 2000, as Manager of Resource Planning. In that capacity, I directed the development, filing, and acceptance of two integrated resource plans with the Commission. I have been employed at my current position with Xcel Energy Services Inc. since August 2004. My resume is provided as Exhibit ___(EME-1), Schedule 1.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS PROCEEDING?

A. No, I have not filed previous testimony in this proceeding

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

A. Yes, it was.

Q. ARE THERE OTHER WITNESSES YOU RELIED UPON IN DEVELOPING YOUR REBUTTAL TESTIMONY?

A. Yes. I have relied upon and incorporated the results from the Rebuttal Testimony of various other Company witnesses in this proceeding, to which I refer in this Rebuttal Testimony.

II. SUMMARY AND ORGANIZATION

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is threefold. First, I will address specific disallowances recommended by Mr. Charles King, presented on behalf of the Advocacy Staff of the North Dakota Public Service Commission (the "Commission") for the Allen S. King Plant, the High Bridge Plant and certain renewable facilities. Second, I will address Mr. King's recommendation that Xcel Energy file a North Dakota-specific resource plan and present our proposal for better coordinating our planning with all of our jurisdictions. Finally, I will provide support for Mr. Kent Larson's Rebuttal Testimony regarding the benefits of maintaining an integrated system.

Q. PLEASE PROVIDE A SUMMARY OF YOUR REBUTTAL TESTIMONY.

A. As discussed in the following sections of my Rebuttal Testimony, I have reached the following conclusions:

- *Discussion of Key Investments.* Our investments in the Allen S. King Plant and the High Bridge Plant are cost-effective responses to critical reliability and environmental needs at these facilities.

- *Renewable Energy Development.* Our renewable energy projects, including the Grand Meadow Wind Farm and associated wind transmission outlet, are cost-effective investments and were acquired through competitive processes. Additionally, our investments in Refuse-Derived Fuel ("RDF") facilities have been part of our system for quite some time and deliver cost-effective energy to our customers.
- *Benefits of an Integrated System.* Customers throughout our system receive significant benefits by being part of a 10,000 MW integrated system. My Testimony further supports the information provided in the Rebuttal Testimony of Mr. Larson.
- *Planning Proposal.* A proposed resource planning filing for North Dakota would be an effective means of addressing current and future concerns regarding our generation portfolio. I provide information to further support the proposal outlined by Mr. Larson.

I therefore recommend that the Commission not adopt the disallowances recommended by Mr. King and instead approve the resource planning process proposed by Mr. Larson and further outlined in my Rebuttal Testimony.

III. DISCUSSION OF KEY INVESTMENTS

Q. WHAT ARE THE KEY INVESTMENTS THAT MR. KING RECOMMENDS BE DISALLOWED IN THIS CASE?

A. As noted in Mr. Larson's Rebuttal Testimony, Mr. King recommends disallowance of several key investments, including:

- The costs of rehabilitating and extending the life of the Allen S. King Plant.

- The costs of constructing a new, 515 MW natural gas-fired combined cycle plant at High Bridge.
- 25 percent of the costs associated with the Grand Meadow Wind Farm and new transmission facilities constructed to carry wind energy. In addition, Mr. King recommends an adjustment to base rates to reflect a similar 25 percent cost reduction for the contracted wind energy that currently flows through the fuel clause.
- The costs associated with our refuse-derived fuel facilities.

The first two of these items are projects associated with our Metropolitan Emissions Reduction Project ("MERP").

Q. PLEASE DESCRIBE XCEL ENERGY'S MERP INITIATIVE.

A. In 2001, the Minnesota legislature passed the Emissions Reduction Statute, Minn. Stat. § 216B.1692. This statute provides a mechanism to facilitate emissions reductions by establishing a streamlined process for developing, approving, and implementing appropriate projects. We initially proposed our MERP project in May 2003, when Xcel Energy selected construction projects at three of our older metropolitan coal-fired power plants for major rehabilitation or repowering.

Q. PLEASE DESCRIBE THE THREE PROJECTS THAT WERE PART OF YOUR MERP PROPOSAL.

A. The three projects are:

- *Allen S King.* To ensure long-term benefits to our customers, we proposed state-of-the-art pollution control equipment and major rehabilitation/life extension work. The resulting project makes this plant available to serve

our customers for at least an additional 25 years. In addition, the project resulted in the recovery 60 MW of capacity and energy that had been lost due to degradation and fuel switching, restoring the King plant to its full original output of 564 MW. This additional capacity and energy is now available to serve our customers at very little additional operating cost or fuel. The rehabilitated King facility began operations in July of 2007.

- *High Bridge*. We proposed to replace this 272-MW, older coal plant with a 515-MW, natural gas combined-cycle facility located at the same site. This conversion uses existing infrastructure that is critical to maintaining the reliability of our system. The new facility at High Bridge began operation in May 2008.
- *Riverside*. We proposed to replace existing unit 7 at this coal-fired plant with two natural gas combustion turbines operating in a combined-cycle. We will retire existing Unit 8. This portion of our MERP project will provide approximately 439 MW of accreditable capacity (a net increase in URGE capacity of about 53 MW) while eliminating coal emissions from this site. Implementation of this project will begin in September of 2008. Thus, no costs related to this project are included in the test year in this proceeding.

Q. WAS ANY PORTION OF THIS PROJECT MANDATED BY MINNESOTA LAW?

A. No. In fact, the MERP statute prohibits consideration of projects that are mandated or a result of corrective action due to being out of compliance with current standards. Xcel Energy proceeded with development of the three above-described projects on a voluntary basis because we believed they would provide significant benefits to our customers throughout our service territories. I will elaborate on these benefits below.

Q. WHAT WAS XCEL ENERGY'S APPROACH TO SELECTING PROJECTS FOR INCLUSION IN THE MERP PROPOSAL?

A. We chose an expansive approach that would achieve multiple goals, benefitting our customers, our system, and other stakeholders. In addition to meeting the environmental requirements to be considered under the Emissions Reduction Statute, we selected projects that:

- Created energy-supply benefits by adding approximately 400 MW of additional capacity to meet our customers' needs.
- Produced additional capacity and energy without significant new transmission infrastructure.
- Maximized the use of existing plant sites and other infrastructure, keeping generation located at critical interfaces on the system.
- Maintained needed fuel diversity.
- Met current and expected environmental requirements for generation facilities.
- Hedged future risks to the Company and the region.
- Responded to community concerns.

We intentionally combined these three plants into one emissions reduction project. This approach allowed us to effectively structure and coordinate our operation of the plants during construction, best maintaining the reliability of our system while these critical projects were being implemented.

Q. DID XCEL ENERGY CONSIDER AN ALTERNATIVE APPROACH TO THE MERP PROPOSAL?

A. Yes. We proposed an alternative plan for consideration that was approximately half the cost of our proposal, but achieved *less than* half the benefits. The alternative would have kept all three plants on coal and would have required major emissions upgrades at each of the three sites. The alternative plan would not have resulted in any additional capacity at High Bridge and Riverside. Based on cost-benefit analyses conducted by the Company, as well as analyses undertaken by the Minnesota Pollution Control Agency ("MPCA"), Xcel Energy did not recommend the alternative plan.

A. King Plant

Q. WHAT WAS THE KING PLANT'S CONDITION AT THE TIME THE MERP PROPOSAL WAS MADE?

A. The King Plant was in need of significant upgrades in order to be able to remain a reliable part of Xcel Energy's generation fleet. The King Plant had reached the end of its economic life and would have ceased operations in 2005. Because of its importance to the energy supply system, its age and its high level of operation over many years, King needed attention at the time our proposal was made. By 2001, the forced outage rate at King Plant had risen to levels that caused us concern, and the plant was experiencing a number of problems that are typical of a heavily used facility of its vintage.

This was the primary reason why we proposed the rehabilitation and life extension work in addition to adding the air quality control systems to that facility. It is also the primary reason why Xcel Energy proposed to implement the King Plant upgrades first.

Q. IF THE KING PLANT COULD NOT BE REHABILITATED THROUGH THE MERP PROJECT, WHAT WOULD XCEL ENERGY HAVE DONE TO REPLACE THE CAPACITY AND ENERGY FROM THE KING PLANT?

A. Due to the stability needs of the electric grid in the area, we would have needed to construct a new coal plant or a new natural gas combined-cycle plant at or near the same system interface at which the King Plant is located -- retiring the plant without replacement of the generating capacity at or near the existing location was simply not feasible.

Our evaluation determined that constructing new coal generation at this location was infeasible for a variety of reasons, including space constraints, permitting concerns, and cost. Constructing a combined cycle natural gas facility at the King Plant site could have been feasible, but we concluded was not the best use for this site, particularly when considering this project in conjunction with the other MERP plants.

Instead, our proposal included the continuation of King as a coal-fired generating plant, which enhanced fuel diversity for our system compared to other alternatives for this site, and resulted in the reclamation of 60 MW of capacity at comparatively very little incremental cost.

Q. AT THE TIME MERP WAS PROPOSED, WHAT WAS THE COST ESTIMATE FOR REPLACING KING PLANT GENERATION WITH NEW GENERATION RESOURCES?

A. Our King Plant environmental upgrades and rehabilitation project as completed cost around $851/kW installed, including all transmission necessary to deliver the energy to the integrated system. Assuming that new generation could have been constructed at or near the King Plant site, we had estimated new base load coal generation at roughly $1,500/kW to $1,800/kW. (Note

that these costs do not include the cost of new transmission that might be needed because of a change to the basic plant configuration.) Our estimates of the cost of natural gas combined-cycle construction were roughly in the $711/kW to $827/kW installed range, not including any related transmission costs.

Based on these facts, we concluded that the overall MERP project rehabilitation of the King Plant was the best option for our customers.

Q. MR. KING SUGGESTS THAT THE COMPANY SHOULD HAVE DELAYED THE REHABILITATION PROJECT AT THE KING PLANT. WAS DELAY A VIABLE ALTERNATIVE?

A. No. As I have discussed above, the King Plant was at the end of its useful life and was experiencing problems that were typical of facilities of that vintage. It would have been retired in 2005. Rehabilitation was needed in the timeframe of our MERP project to ensure the plant's long-term availability to our fleet.

Q. CAN YOU PROVIDE SOME EXAMPLES OF THE DEGRADATION EXISTING AT THE KING PLANT PRIOR TO ITS REHABILITATION?

A. Yes. In 2001, our Energy Supply division conducted condition assessments of the both the boiler and the steam turbine. The pressure retaining components of the boiler were failing on a regular basis, reducing the availability, reliability, and capacity factor of the plant. Data showed that the frequency of the failures was rising at an increasing rate. Babcock and Wilcox ("B&W"), our consulting engineers, conducted an assessment of the boiler and found that the boiler floor was in poor condition: physically distorted and metallurgically weak. B&W also reported that the floor and the cyclone burners of the King Boiler were the longest surviving original components of 1960's vintage

cyclone-fired, supercritical boilers. All similar boilers built by B&W had floors and cyclones that had been replaced at least once, with some units having replaced some or all of those components twice. Based on this information and actual experience with plant performance, it was obvious that swift action was needed for the King facility.

Q. HOW DID THE COMPANY RESPOND TO THIS SITUATION AT THE KING FACILITY?

A. After careful consideration, the Company selected and conducted preliminary design of the King rehabilitation project. As already discussed, this project provided numerous benefits, including:

- We extended the life of the plant by 25 years or more, ensuring continued low-cost, reliable energy for our customers.
- We improved the efficiency of the plant.
- We reclaimed 60 MW of capacity and energy that had been lost to degradation, at virtually no increase in operating or fuel costs.
- We were able to do this at a cost that was roughly one-third of the cost of constructing a new coal-fired facility, before consideration of transmission costs.

B. High Bridge

Q. PLEASE DESCRIBE THE PURPOSE FOR THE HIGH BRIDGE RETROFIT PROJECT.

A. Similar to the King Plant, the High Bridge Plant was nearing the end of its useful life. To maintain the viability of this facility, action was needed in the immediate future. This retrofit project increased capacity and preserved existing transmission and other infrastructure at a strategic location on the system, while eliminating coal generation from an urban environment. It was

not prudent to abandon generation at this strategic location, but the long-term use of coal at that sight was increasingly problematic. Switching to natural-gas-fired generation was the best long-term solution for our customers.

Q. WERE ALTERNATIVES TO SWITCHING TO NATURAL GAS CONSIDERED FOR THE HIGH BRIDGE PLANT?

A. Yes. We proposed an alternative plan that would have kept the plant on coal, while providing for environmental upgrades to the plant. However, the alternative project for High Bridge was not nearly as advantageous as the conversion to natural gas. The conversion allowed us to nearly double the capacity at this site, allowing us to defer investment in new, green-field capacity and energy for several years. Expansion of generation capacity using coal was not possible, due to the limited space available for plant expansion and coal inventory at this relatively small, urban site.

Q. WOULD MAINTAINING THE HIGH BRIDGE PLANT AS A COAL PLANT AND IMPLEMENTING THE COAL REHABILITATION ALTERNATIVE BEEN AN EFFECTIVE ALTERNATIVE?

A. I believe it would have been very difficult to implement the coal rehabilitation alternative at this site; at best, it would have significantly delayed implementation of a project and our ability to secure the High Bridge Plant as a continued, effective contributor to overall system reliability. The MPCA was charged by statute to conduct an analysis of both our proposal and our alternative, and assess their feasibility as well as determine whether they constituted cost-effective solutions alternative that would be appropriate for implementation. The MPCA conducted a thorough analysis of the High Bridge coal alternative.

Initially, the MPCA rejected our coal alternative plan for High Bridge as not satisfying the EPA's Best Available Control Technology ("BACT") requirements. The MPCA concluded that the High Bridge Plant alternative was not adequate to satisfy BACT or the EPA's New Source Performance Standards. In addition, the MPCA pointed out that extensive rehabilitation of the plant would have been necessary in addition to the installation of anti-pollution control equipment. In sum, the MPCA concluded that the cost and benefit of the proposed coal High Bridge Plant alternative was inadequate and that this alternative should be rejected.

The MPCA continued to study the High Bridge alternative. Its subsequent report concluded that the coal alternative was not a cost-effective way to proceed. While the MPCA modified its position on whether the coal alternative would satisfy the relevant EPA and MPCA pollution requirements, it concluded that keeping the plant on coal was not the most cost-effective approach.

In addition, other parties, including a variety of community and health organizations, submitted comments that the coal alternative at the High Bridge Plant should be rejected. Their recommendations were based on several concerns related to continued use of coal generation in a densely populated urban environment. Based on the record of that proceeding, we believe it would have been very difficult to successfully implement the coal alternative. At a minimum would almost certainly have entailed significant delay in addressing a critical reliability issue for our system

Finally, Mr. Rosvold provides additional information regarding the broader environmental compliance issues we faced with our generation fleet and how our MERP projects helped deal with these issues in a consistent and foresighted manner.

In summary, unlike the King facility, the coal alternative at the High Bridge Plant could not achieve the goals of: (i) maintenance of a high level of reliability at this critical site in a timely manner; and (ii) expansion of needed generation capacity for the benefit of all of our customers.

Q. IF XCEL ENERGY HAD PURSUED THE OPTION OF REHABILITATING HIGH BRIDGE AS A COAL PLANT, WHAT COSTS WOULD HAVE BEEN INCURRED FOR THE ADDITIONAL CAPACITY AND ENERGY NEEDED TO MEET CUSTOMER LOAD?

A. There would have been several additional costs in addition to the $73 million of environmental upgrades. First, we would have had to replace nearly 250 MW of capacity that was needed to serve our customers' growing requirements but would not be provided through the MERP projects. If we were to place this capacity elsewhere on our system, we would have incurred not just the costs of the capacity, but also the costs of acquiring land, developing infrastructure and building transmission -- all of which were already present at the High Bridge site. This strategy would not have permitted the Company to make optimal use of our existing land and transmission infrastructure, both vital inputs into timely and successful completion of generation projects.

Q. HOW DOES THE SIZE OF THE NEW HIGH BRIDGE PLANT COMPARE WITH THE CAPACITY AND ENERGY OF A REHABILITATED HIGH BRIDGE COAL PLANT?

A. The original High Bridge coal plant was 243 MW. The High Bridge natural gas conversion project resulted in 515 MW of capacity on our system, a net increase of 272 MW. In contrast, the alternative project would have resulted in a net decrease of capacity of about 4.4 MW (as a result of the operation of some of the air quality equipment). In light of the increasing needs for capacity expansion in our region, the expansion of capacity at this site provides large reliability benefits for our entire system.

Q. WHAT WOULD HAVE BEEN THE COST OF REPLACING THE HIGH BRIDGE PLANT AT A LATER DATE, HAD XCEL ENERGY NOT PURSUED PROJECTS THROUGH THE MERP PROCESS?

A. The costs of installing new generating facilities have risen rapidly in the past five years. At the time we proposed MERP, we estimated the installed cost of new combined cycle generation to be between $711/kW and $827/kW. Our current estimate for a new, combined-cycle generating facility is over $1100/kW, more than 33 percent higher. The savings from converting High Bridge when we did is even greater than this difference, because we were able to acquire low-cost turbines on the secondary market. Based on current demand for turbines, it is unlikely that we could have replicated that experience later.

Q. HAS THE ADDITION OF INCREASED CAPACITY AT THE HIGH BRIDGE PLANT MITIGATED TRANSMISSION CONGESTION AND ULTIMATELY COSTS FOR ALL CUSTOMERS?

A. Yes. High Bridge is located in the heart of a densely populated metropolitan area. Most of our key baseload plants, including our nuclear and large coal facilities, are located significant distances from our load centers. To facilitate the siting of these large baseload facilities outside of metropolitan areas, the

Company must continue to maintain some resources within load centers to ensure transmission stability and minimize overall transmission congestion. Further, in the Midwest Independent Transmission Operator ("MISO") Day 2 environment, which began operation in April 2005, energy providers are directly assessed costs for the transmission congestion they impose on the system by delivering energy from generators to load. The High Bridge Plant location helps mitigate these costs for all ratepayers.

Q. PLEASE SUMMARIZE THE BENEFITS OF CONVERTING THE HIGH BRIDGE PLANT TO A NATURAL GAS COMBINED CYCLE AT THE TIME OF THE MERP CONVERSION.

A. There were several key benefits of having pursued and implemented the High Bridge project when we did:

- We were able to expand capacity and energy to meet our growing customer needs throughout our service territory.
- The operational flexibility provided by the new gas-fired units provides improved system reliability, as our system must respond rapidly to hourly changes in resource and load conditions.
- Retaining the High Bridge site allowed us to make best use of existing infrastructure, providing cost savings for our customers.
- Similar benefits accrued to our customers through use of the existing transmission infrastructure. We were also able to avoid potential construction delays that frequently occur with new transmission additions.
- By acting quickly, the Company was able to gain access to low-cost turbines on the secondary market.
- As discussed further in Mr. Richard Rosvold's Rebuttal Testimony, we were able to proactively address future environmental concerns.

C. Summary of MERP Benefits

Q. IN SUMMARY, CAN YOU EXPLAIN WHY XCEL ENERGY UNDERTOOK THE MERP PROJECTS?

A. These projects achieve significant and lasting benefits for our customers through extended lives of critical plants on our system, increased capacity, and efficient use of existing infrastructure. In addition, as discussed in Mr. Rosvold's Rebuttal Testimony, we believe that the MERP projects significantly mitigated the risk of possible future environmental regulatory action. Given that any rehabilitation and repowering project is a significant undertaking, it made more sense to undertake an approach that hedged against potential future requirements than to implement a significant project that did not provide this hedge.

Q. WERE THERE OTHER BENEFITS OF PROCEEDING TO IMPLEMENT UPGRADES AT THE KING AND HIGH BRIDGE PLANTS WHEN THE COMPANY DID?

A. Yes. The repower and rehabilitation projects also avoided the project development risks associated with potential new generation sources. Siting new generation and – perhaps more importantly – any required new transmission facilities can take a significant amount of time and effort and is potentially subject to significant proceedings, including litigation, before construction can occur. Developing additional capacity at existing sites that do not require such proceedings offered a hedge against the risk of delay.

Q. WAS DELAYING THE PROJECTS A FEASIBLE OUTCOME?

A. No. The option to take no action at the time was not feasible. Both the King and the High Bridge plants were at or near the end of their useful lives. Major

rehabilitation of these plants (both of which would have been necessary in the immediate future) would have triggered Federal New Source Performance Standards environmental regulations that require the installation of environmental control equipment. As a result, a 'do-nothing' approach would have simply resulted in future modifications to the plants that would have been comparable to the Company's alternative plan, but would have also required additional costs associated with life extension activities.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE COMPANY'S KEY INVESTMENTS AT THE KING AND HIGH BRIDGE PLANTS.

A. Our investments at both King and High Bridge are proactive responses to changes in economic and regulatory conditions. The investments did not, as Mr. King suggests, simply involve the addition of environmental controls that went beyond what was required by Federal law. To the contrary, the projects resulted in expanded capacity and energy, extended unit lives and increased reliability for our customers at a cost far below what it would have been to construct new facilities. These investments will provide long-term benefits to our customers throughout our service territory. For each facility, we believe we made the correct choice of resource and set the Company on a timely path to meet our customers' needs and expanding environmental requirements.

IV. RENEWABLE ENERGY STANDARDS

Q. ARE THERE OVERALL BENEFITS FROM XCEL ENERGY'S WIND ADDITIONS TO ALL CUSTOMERS, REGARDLESS OF WHETHER THESE WERE IN RESPONSE TO MINNESOTA MANDATES?

A. Yes. Although the wind has been installed on our system in response to initiatives of the Minnesota legislature, it has proven to be a cost-effective

resource for all of our customers. In 2007, for example, the average cost of wind on our system was $32.16/MWh, while the average MISO market price was roughly $55.00/MWh. Without the wind in our portfolio, all of our customers -- including those in North Dakota -- would have paid higher costs for their energy. In addition, the wind energy has avoided emissions of SO_2 and NO_x allowing Xcel Energy to avoid purchase of allowances necessary to emit those pollutants.

Q. WHAT WERE THE BENEFITS OF SITING THE WIND ENERGY FACILITIES WHERE THEY ARE?

A. Generally speaking, Xcel Energy contracted for all of the wind through a competitive process. The sites where our wind energy is currently located were selected because the combination of wind speed (which helps determine capacity factor), transmission, and other infrastructure producing the lowest cost wind energy. In addition to capacity factors and transmission access, the State of Minnesota adopted favorable incentives such as sales and property tax exemptions in the early 1990s to encourage wind development. All of these factors combined to produce low cost offers to supply wind energy and provide significant benefits for our customers today.

Q. WHAT PARTICULAR BENEFITS DID CUSTOMERS RECEIVE THROUGH XCEL ENERGY PURCHASING THE GRAND MEADOW WIND FARM?

A. The Grand Meadow Wind Farm is located in a particularly good area for wind resources and relatively uncongested transmission. In addition, the project was already well along in the development process, as it had access to wind turbines and a favorable position in the Midwest Independent System Operator's ("MISO's") interconnection queue. This last factor is critical to the development process, as the interconnection queue currently contains over

20,000 MW of wind projects in our area, and it is estimated that it will take many years to study and interconnect all currently proposed projects. The ability to interconnect the project quickly allowed us to take advantage of the Federal Production Tax Credit on wind energy, which is set to expire at the end of 2008. This tax benefit alone is worth $20.00 per MWh for the first ten years, or more than 16 percent of the cost of the Grand Meadow project.

Q. TO THE EXTENT THEY EXIST, WOULD THE HIGHER CAPACITY FACTORS AVAILABLE IN NORTH DAKOTA NECESSARILY TRANSLATE TO 25 PERCENT LOWER WIND COSTS FOR XCEL ENERGY CUSTOMERS?

A. No. While North Dakota does have a favorable wind regime that can result in higher capacity factors from wind turbines, the wind sites are remote from load and there is very little transmission infrastructure currently available to support the transmission of the wind to load. Thus any cost savings that may be achieved from higher capacity factors would need to be balanced against the costs of constructing major transmission lines.

Q. HAVE WIND PROJECT DEVELOPERS PROPOSED PROJECTS IN NORTH DAKOTA IN RESPONSE TO OUR COMPETITIVE PROCESSES FOR WIND ACQUISITION?

A. Yes. While several North Dakota sites have been offered, they have not proven to be the best resource when taking all key factors into account. Clearly, the largest impediment to successful offers from North Dakota projects has been the lack of transmission access. As discussed below, the Company is working to address this issue for the future.

Q. MR. KING ALSO PROPOSES AN ADJUSTMENT TO BASE RATES TO REFLECT A 25 PERCENT REDUCTION IN THE COST OF OUR PURCHASED WIND, WHICH IS

CURRENTLY COLLECTED THROUGH THE FUEL ADJUSTMENT CLAUSE. IS THIS ADJUSTMENT REASONABLE?

A. For the same reasons noted above, this type of adjustment would not be reasonable. The adjustment assumes that the purchased wind facilities could have been constructed elsewhere at a cost that was 25 percent below what was agreed to under existing contracts entered into through a competitive bidding process. Because infrastructure costs in other locations would have been higher, we would not have been able to achieve those cost reductions even under more favorable wind regimes.

Q. HOW MUCH WIND WILL XCEL ENERGY EVENTUALLY NEED TO PLACE ON ITS SYSTEM?

A. To meet renewables requirements in all of its jurisdictions, Xcel Energy estimates that we will have over 4,000 MW of wind on our system by 2020.

Q. WILL ALL OF THIS WIND BE LOCATED IN MINNESOTA?

A. No. Xcel Energy plans to develop wind facilities in wind-rich areas throughout its service area, including North Dakota. As noted by Mr. Larson in his Rebuttal Testimony, we have applied for approval to construct a new 345 kV transmission line extending from Fargo to the Twin Cities that will allow us to export additional energy from North Dakota. We are currently evaluating several North Dakota projects as part of our recent 500 MW wind ownership solicitation. Xcel Energy recognizes the benefits of diversifying wind resources over as large an area as possible and is affirmatively planning and investing in our system to this end.

Q. PLEASE DESCRIBE THE BIOMASS FACILITIES THAT MR. KING RECOMMENDS DISALLOWING.

A. Mr. King recommends that the Commission disallow the rate base items related to our refuse-derived fuel facilities ("RDF"). These facilities include:

- Our Red Wing plant, a 20 MW plant which was constructed in 1949 as a coal plant and converted to RDF in 1984;
- Our Wilmarth plant, a 20 MW plant which was constructed between 1941 and 1948 as a coal plant and converted to RDF in 1984; and
- Our French Island plant, a 25 MW plant that was constructed as a coal plant between 1940 and 1948 and was converted to burn wood waste and RDF in 1986.

The basis for this recommended disallowance is Mr. King's claim that these investments are responsive to the Minnesota mandates for renewable energy.

Q. WERE THESE FACILITIES CONSTRUCTED TO MEET MINNESOTA RENEWABLES REQUIREMENTS?

A. No. These facilities have been a reliable part of our integrated system since the 1940s, long before the Minnesota legislature passed any renewable requirements. They were approved as a part of North Dakota electric rates in our 1992 rate case and in prior cases. The facilities meet the definition of "eligible energy technology" in Minnesota Statutes 216B.1691; therefore we can count them toward meeting our renewables requirements, even though we did not build them to meet those requirements. Xcel Energy also has several owned and contracted hydro facilities that were developed pre-1970, but can be counted toward our renewables requirements. Despite the fact that we can count these facilities for the purpose of meeting our renewable requirements, these projects were not, as Mr. King assumed, undertaken in response to any new Minnesota renewable energy requirement.

Q. DOES THE ABILITY TO COUNT THESE FACILITIES TOWARD RENEWABLE REQUIREMENTS BENEFIT NORTH DAKOTA CUSTOMERS?

A. Yes. Our existing biomass and hydro facilities provide about three percent of our retail energy requirements. Since Xcel Energy can count these embedded facilities toward meeting our renewables requirements and because these already significantly depreciated costs are lower than the costs of new facilities, the amount of new renewables that we will need to install to meet our overall requirements, and our overall compliance costs are lower for all of our customers.

V. BENEFITS OF AN INTEGRATED SYSTEM

Q. MR. LARSON DISCUSSES THE BENEFITS OF AN INTEGRATED SYSTEM IN HIS REBUTTAL TESTIMONY. BASED ON YOUR EXPERIENCE IN SYSTEM PLANNING AND RESOURCE ACQUISITION, CAN YOU ELABORATE FURTHER ON THESE OVERALL BENEFITS?

A. Yes. As discussed above, my primary responsibilities with the Company are to determine the resources needed for the Company to continue to fulfill our customers' growing energy requirements and to secure those resources in the most cost-effective and environmentally responsible manner possible. The resource options that are available to a large integrated system such as ours are numerous and are due in large part to the overall size of the customer base we serve. As a 10,000 MW system, we can consider large resource additions of significant size to take full advantage of the economies of scale available through large facility generation.

For example, the addition of 515 MW at the new High Bridge facility completed this spring could not have easily been absorbed into a smaller, stand-alone system. The fuel efficiency of the combined cycle units now available at the new High Bridge facility represents a 45 percent advantage compared to the addition of a smaller, simple cycle turbine. Based on current fuel prices, this translates into a cost savings of $35/MWh or over $70 million per year in savings for all of our customers.

Similar advantages are made available due to the load diversity on our system. Our overall system load factor is approximately 59.7 percent, meaning that our customers use energy that is nearly 60 percent of the potential energy on our system based on our peak load. While some large integrated systems throughout the country may have similar system load factors, it is quite difficult for smaller systems to achieve this level of efficiency. Thus, for a smaller system, a larger percentage of load will be exposed to on-peak market prices a larger percentage of the time than would be the case for larger systems. Given that on-peak prices for energy in our region are currently double to triple the level of off-peak prices, this is a significant benefit for larger, integrated systems.

Finally, as discussed by Mr. Larson, the Company has built a highly diverse fleet of generation and load management resources. Figure 1 in Mr. Larson's Rebuttal Testimony provides a summary of the relative contributions from all of our resources to meeting the needs of our customers. It is obvious from this schedule that the Company has limited our customers' exposure to price volatility from any single resource.

Q. PLEASE ELABORATE ON THE BENEFITS OF A LARGE INTEGRATED SYSTEM FROM A RESOURCE ACQUISITION PERSPECTIVE.

A. When the Company wishes to acquire new generation resources, it can issue RFPs for new resources exceeding 150 MWs in size. RFPs of this magnitude are sufficient to draw the attention of large developers with resources available to both bring large projects on-line in a timely manner and assume the numerous risks present in power plant development. We can also weigh these offers against large Company-owned projects that provide other advantages. It would be difficult for a smaller stand-alone system to participate effectively in this market.

This ability to construct larger facilities is still key to achieving economies in the electric industry. For example, the cost of constructing a 600-MW, 2x1 combined cycle facility is at least 10 percent less expensive per kilowatt than the smaller, 300 MW 1x1 combined cycle facility. These cost savings are passed directly on to our customers in the form of lower rates.

There are also advantages to size in the mid-term and short-term power acquisition markets that the Company must operate in to meet customers' needs. The Company has developed extensive energy trading and risk management expertise to better serve our customers in the mid-term markets and the day-ahead and real-time markets facilitated by MISO. It would be less cost-effective for a smaller entity to develop the expertise needed to participate in these markets.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE BENEFITS TO ALL CUSTOMERS OF BEING PART OF A LARGE INTEGRATED SYSTEM.

A. There are significant advantages to being a part of a larger, integrated system that result primarily from the existence of economies to scale in the electric power industry. I have attempted to provide examples of these advantages. While some advantages are more difficult to quantify, I believe that my discussion demonstrates the overall advantages of participation in a large integrated system compared to system planning and resource acquisition on a stand-alone basis.

VI. RESOURCE PLAN

Q. HOW DOES XCEL ENERGY DEVELOP A RESOURCE PLAN?

A. Xcel Energy develops resource plans on the basis of an integrated system that serves both the NSP-Minnesota and the NSP-Wisconsin operating companies of Xcel Energy Inc. We examine the capacity and energy needs of our customers as well as the regulatory and legal requirements in each of our jurisdictions, and then design a plan that meets all requirements at the lowest possible cost. We use a dynamic programming model (called "Strategist") that allows us to look at various scenarios and ensure that our resource plan provides customers with reliable, low-cost energy under a number of possible outcomes.

Q. WHAT IS THE OVERALL BENEFIT OF THE PLANNING METHODOLOGY?

A. Planning on the basis of an integrated system allows us to take advantage of economies of scale as well as the diversity of customer needs to provide lower costs to all of our customers. For example, we are able to construct larger and more economical facilities such as our nuclear plants and our 2400 MW Sherco coal-fired generating facility. We are also able to maintain one of the most diverse fuel mixes of any utility in the country, using coal, nuclear, hydro,

natural gas, wind, biomass, and oil to serve our customers' energy needs. In addition, we are able to coordinate the requirements of our various jurisdictions and develop a plan that meets all of those requirements at the lowest possible cost.

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

A. No. If we were required to file a state-specific resource plan in North Dakota or elsewhere, we would no longer be able to plan on an integrated basis. Instead, we would need to propose specific resources to meet local needs and policies that would not necessarily comply with the needs of other jurisdictions. This approach could result in a number of conflicts for the Company, and higher overall costs for all of our customers.

For example, if the Commission were to determine that our North Dakota resource plan should not include wind energy in excess of its own state objectives, we would need to include energy from other resources to make up for the wind energy that would no longer be going to North Dakota customers. This disaggregation would either involve construction of smaller, more costly resources to meet North Dakota's exclusive needs or, more likely, result in market purchases that would need to be paid for by North Dakota customers. As noted above, the cost of our wind resources is currently far below the market price, so such a decision would raise costs to North Dakota consumers.

Similarly, our North Dakota load is simply not large enough to support the construction of a large stand-alone generating facility such as a coal-fired plant. Implementing such a requirement, were the Commission to impose it, would

require agreement from all other jurisdictions, as a share of the costs and resource would need to be allocated across our entire service territory for such a plant to approach feasibility. In short, if we were to construct facilities to meet only North Dakota goals and requirements, our North Dakota customers would lose the benefits of diversity of load and resources that help keep costs low for all of our customers.

Q. WHAT CAN XCEL ENERGY DO TO OBTAIN MORE INPUT FROM NORTH DAKOTA ON ITS RESOURCE PLAN?

A. Xcel Energy recognizes that the Commission desires more input into and participation in our planning process, and we welcome that input. To ensure we obtain the full benefit of an integrated system, we believe that input from the Commission would be of the greatest value at the time we are developing our resource plan.

To that end, we propose a collaborative planning process that would take place approximately three months prior to our resource plan being completed. Through this process we would meet with the state utility commissions and staffs in all of our NSP jurisdictions to obtain specific information on their goals and requirements for Xcel Energy's resource plan. In addition, we would encourage and facilitate joint meetings of regulators from each jurisdiction to discuss specific concerns and conflicts between various goals and requirements. We would expect this process to be iterative; as Xcel Energy uses the information from these meetings to help develop our plan, we would share developments with our regulators for additional feedback.

While details of this process still need further development, we believe that using this process will help us create a single, integrated, long-term resource

plan that brings benefits to all of our jurisdictions and addresses the specific concerns of the Commission.

Q. CAN XCEL ENERGY MODIFY THE PLANNING PROCESS TO ADDRESS THE COMMISSION'S CONCERNS ABOUT THE LOCATION OF GENERATING FACILITIES?

A. I believe so, yes. Since the 1990s, Xcel Energy has procured our resources through competitive processes. These processes have focused on finding the lowest-cost resources for our customers, regardless of location.

We understand that all of our jurisdictions are interested in the benefits that come from the location of generating facilities in their respective states. While we cannot commit to placing facilities in particular jurisdictions, we can consider modifying our planning criteria to provide added emphasis to location preferences when considering and selecting resources. In addition, we can work specifically within our acquisition process to identify cost-effective supply opportunities in all of our jurisdictions.

Again, this initiative requires further development. However, I offer it to indicate there are useful approaches available that may address any concerns the Commission has regarding our processes. The Company is opening to exploring and refining such processes, as the Commission desires.

VII. SUMMARY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. Our North Dakota customers enjoy the benefits of low-cost and reliable energy as part of a large, integrated electric system. We develop our resource plans to meet our customers' needs and the requirements of each of our

jurisdictions at the lowest possible cost and in an environmentally responsible manner. While this approach may require one jurisdiction to supports costs that result from other jurisdictional requirements, all of our customers benefit from this approach, compared to separate planning and construction of each system.

The investments in our King, High Bridge, wind and biomass facilities have provided expanded capacity, extended lives and increased reliability on our system that benefit all of our customers. The rehabilitation and repowering of King and High Bridge resulted in the addition of over 300 MW of new capacity and energy to serve our customers' growing needs at a cost that would be much lower than development at a new site. Our wind facilities were constructed in locations that avoided the cost of extensive transmission infrastructure and today provide costs that are on average more than 40 percent below the current market. Our biomass facilities, long a part of the Xcel Energy system, reduce the need for us to add new renewables to meet regulatory requirements.

While the investments we have included in this case are reasonable and prudent, we acknowledge that both Xcel Energy and our customers could benefit from greater regulatory participation in our planning process. We propose to establish a process that will allow us to obtain early input from our regulators as we develop our plans, and receive continued feedback as our plans progress. In addition, we propose to work to identify and acquire cost-effective supply resources in each of our jurisdictions. These proposals will allow us to ensure that the goals of each jurisdiction are heard, carefully balanced, and addressed as we expand our system to meet future energy needs.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

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

AFFIDAVIT OF
Elizabeth M. Engelking

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.

Elizabeth M. Engelking

Subscribed and sworn to before me, this 17th day of June, 2008.

Notary Public

Elizabeth M Engelking
Xcel Energy
414 Nicollet Mall
Minneapolis, Minnesota 55401

EDUCATION

Master of Business Administration, Carlson School of Management
University of Minnesota, 1986

Bachelor of Sciences
College of William and Mary in Virginia, 1982

CURRENT RESPONSIBILITIES

I direct the development of the Company's long-range Resource Plan and manage the bidding process to procure new long-range resources for the Northern States Power Company (Minnesota and Wisconsin) system.

EMPLOYMENT

Xcel Energy	
2004 – present	Manager, Resource Planning and Bidding
Great River Energy	
2000 – 2004	Manager, Resource Planning
1998 – 2000	Transmission Analyst
Minnesota Public Utilities Commission	
1988 – 1998	Public Utilities Rates Analyst

PREVIOUS PLANNING TESTIMONY

Xcel Energy	E002/CN-05-123	Cost and Alternative Analysis

Rebuttal Testimony
Richard A. Rosvold

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___

Environmental Issues and Investments

June 13, 2008

Table of Contents

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Richard A. Rosvold. I am the Air Quality Manager for the NSP-MN and NSP-WI operating companies' service territories of Xcel Energy Inc. My business address is 414 Nicollet Mall, Minneapolis, Minnesota 55401.

Q. FOR WHOM ARE YOU TESTIFIYING?

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

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. My formal education consists of earning a Bachelor of Chemical Engineering degree with a Pollution Control emphasis from the University of Minnesota in 1988. I have worked in the environmental field (primarily in the air quality area), for the past 20 years, 11 of those with Xcel Energy. I led the project to obtain the air emission permit for the Allen S. King Rehabilitation Project and have been involved with the mercury control planning activities for Xcel Energy. My current responsibilities as Air Quality Manager include permitting and compliance activities for facilities located in Minnesota, Wisconsin, North Dakota and South Dakota.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS PROCEEDING?

A. No, I have not.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to address three issues. First, I will demonstrate that, contrary to Mr. Charles King's assertions made on behalf of the Advocacy Staff of the North Dakota Public Service Commission (the "Commission"), Minnesota's environmental regulations are essentially the same as Federal environmental standards. Second, I will discuss the environmental improvements implemented as part of the Company's Metropolitan Emissions Reduction Project ("MERP") to date, and will explain that these improvements are, or soon will be, needed to meet Federal environmental standards. Third, I will discuss the Company's overall approach to addressing environmental standards, concluding that, to date, we have achieved environmental compliance in a cost-effective and risk-mitigating manner.

II. ENVIRONMENTAL COMPLIANCE

Q. HAS MINNESOTA ADOPTED EMISSION STANDARDS THAT ARE MORE STRINGENT THAN THE FEDERAL STANDARDS?

A. Generally speaking, with the exception of mercury, Minnesota has adopted emission standards that are consistent with Federal standards. Under the Clean Air Act, states have the authority to adopt standards that are more restrictive than Federal rules. In recent years, Minnesota, through the Minnesota Pollution Control Agency ("MPCA"), has chosen to adopt the Environmental Protection Agency's ("EPA") approach on a number of key regulations, thus aligning Minnesota's compliance standards with Federal requirements. For example, Minnesota chose to adopt the Federal Implementation Plan for implementation of the Clean Air Interstate Rule ("CAIR"), rather than to adopt a more stringent,

Minnesota-only program. Another example is that Minnesota chose to rule that Best Available Retrofit Technology ("BART") is equal to CAIR when considering regional haze impacts in Minnesota. Therefore, it would not be accurate to state that Minnesota has adopted emission standards that are more stringent than the EPA's Federal standards for emissions. Further, as will be discussed below, even for the mercury emissions requirements, Minnesota standards will soon be consistent with Federal standards.

Q. MR. KING, AT PAGE 6, TESTIFIES THAT MINNESOTA STANDARDS FOR PARTICULATES AND SULFUR DIOXIDE ARE MUCH MORE STRICT THAN THE EPA STANDARDS. IS THIS ACCURATE?

A. No. Minnesota's standards for these emissions are generally similar to the Federal standards. In fact, Mr. King's Exhibit__(CWK-1) lists both the Minnesota and the EPA standards for Total Particulate Matter, Opacity, Sulfur Dioxide ("SO_2"), NOx, and Particulate Matter as less than 10 Microns. This Exhibit shows that none of the Minnesota standards are higher than the EPA standards.

Q. PLEASE DESCRIBE THE BACKGROUND AND STATUS OF THE EPA'S MERCURY STANDARDS.

A. The EPA promulgated the Clean Air Mercury Rule ("CAMR") on May 18, 2005. CAMR established a national cap-and-trade program for mercury emissions from coal-fired electric generating units with capacities greater than 25 MW. Under CAMR, affected units would have been required to either reduce their mercury emissions or purchase sufficient allowances on the open market for each ounce of mercury emitted each year, beginning in 2010. CAMR based the annual

mercury allowance allocations on a national mercury emission cap of 38 tons per year during Phase I (2010-2017) and a cap of 15 tons per year in Phase II (2018 on), working from a baseline of 48 tons per year. In addition, all affected units were required to begin continuous monitoring of mercury emissions by January 1, 2009.

Q. HOW DID THE COMPANY PLAN TO COMPLY WITH CAMR?

A. The Company has eight units that were subject to the CAMR. Our strategy for complying with Phase I of CAMR was to install mercury emission controls on our largest units and over-control those units, producing enough excess allowances to cover the smaller remaining units. Specifically, the Company planned on installing mercury controls on Sherco 3 in 2009 and on King 1 in 2010 and maximizing mercury control on these units, providing sufficient reductions to comply with the annual allowance allocations for our entire Minnesota coal plant fleet. Our plan was to evaluate the level of mercury removal rates on these units to determine whether to invest in mercury controls on additional units. Our plan also included monitoring how the mercury allowance market developed to determine whether purchasing mercury allowances as a compliance option was more cost-effective than controlling mercury emissions. For our initial planning purposes, we assumed an allowance cost estimate of $35,000 per pound of mercury emitted, the "safety valve" price proposed by the EPA in the CAMR rulemaking process. That cost was selected as a base value until the market actually materialized.

In 2018, Phase II of the CAMR was to begin, and mercury allowance allocations for all units would be reduced. Our strategy was to continue to evaluate whether

to add controls on other units or to purchase allowances in order to comply with Phase II of CAMR.

Our above-outlined strategy was the lowest-cost control option available to us. The economies of scale achieved through installation of mercury emission controls at our largest units were the most cost-effective method available to us, given the cost of mercury emission controls at these facilities and our estimates of future emission allowance prices.

Q. WHAT IS THE CURRENT STATUS OF CAMR?

A. On February 8, 2008, the D.C. Circuit Court of Appeals vacated CAMR, finding that EPA had not provided the necessary evidence under the Clean Air Act Delisting Rule to exempt mercury from the higher standards under Section 112 of the Clean Air Act. On March 24, 2008, the EPA filed a petition asking for review by the full D.C. Circuit to re-hear the decision to vacate CAMR. The Court of Appeals denied this petition. The EPA or other intervenors may appeal this decision.

While the appeals process is still working itself out, by vacating CAMR and the Delisting Rule, the EPA is required under Clean Air Act Section 112 to move forward with the development of a new maximum achievable control technology ("MACT") rule. This requirement has two consequences. First, this new MACT rule would apply to each affected unit, rather than allocating allowances to offset emissions at some facilities through a trading program. Second, the MACT rule will be prescriptive in nature, requiring installation of emission control equipment at each of eight facilities.

EPA's MACT standards are based on the emissions levels already achieved by the best-performing similar facilities. For existing sources, the MACT floor must equal the average emissions limitations currently achieved by the best-performing 12 percent of sources in that source category, if there are 30 or more existing sources. If there are fewer than 30 existing sources, then the MACT floor must equal the average emissions limitation achieved by the best-performing five sources in the category. Based on my review of the industry, it appears that the best-performing sources, using either the top 12 percent or the top fives sources, would equate to a 90 percent removal rate. Although this approach is subject to change, the EPA is expected to propose a Utility MACT standard within 12 months, which would result in final rules being effective in 2010.

Q. HOW WOULD A NEW MACT RULE AFFECT THE COMPANY?

A. The Company expects to have eight units subject to this rule when it is issued. These are the same eight units that would have been subject to CAMR. However, unlike CAMR, the new MACT standard will require maximum achievable emissions reductions at each unit rather than allowing some units to over-control and others to do nothing. In this way, MACT will be more restrictive and expensive than CAMR.

Q. HOW DID CAMR COMPARE TO MERCURY REQUIREMENTS IN MINNESOTA?

A. In 2006, the Minnesota Legislature enacted the Minnesota Mercury Emission Reduction Act of 2006 ("MMERA"). The MMERA requires a public utility that owns a dry-scrubbed or wet-scrubbed coal-fired electric generation unit with capacities greater than 100 megawatts (MW) to propose the use of available technology for mercury removal that is most likely to result in the removal of 90

percent of the mercury emitted from the unit. In addition, affected units under this program are required to begin continuous monitoring of mercury emissions by July 1, 2007.

After enactment of the MMERA, the MPCA chose to adopt the Federal Implementation Plan for implementation of the CAMR, rather than adopt the more stringent approach it was considering. By doing this, Minnesota chose to allow full trading of mercury allowances, something many other states did not allow. The availability of these allowances would have enabled us to use higher-than-required emission reductions at one plant to offset higher emissions at another plant. This increased flexibility lowered the cost of compliance for our customers.

Q. HOW DOES THE MMERA COMPARE TO CAMR AND THE FUTURE MACT?

A. The MMERA is slightly more restrictive than the vacated CAMR rule. However, it will be less restrictive than the future MACT rule that EPA is expected to promulgate. Based on how EPA has applied previous MACT standards to other industries, the new mercury MACT standard will require maximum achievable emissions reductions at each unit rather than allowing some units to over-control and others to do nothing. In this way, MACT will be more expensive to comply with than either CAMR or MMERA. The below table shows a side-by-side comparison of the three regulatory approaches.

Table 1

Comparison of Mercury Control Requirements

	CAMR	MMERA	MACT
Number of Xcel Energy Facilities Affected	8	4	8
Names of Affected Units	Black Dog 3, Black Dog 4, King 1, Minnesota Valley 3, Riverside 8, Sherco 1, Sherco 2, Sherco 3	King 1, Sherco 1, Sherco 2, Sherco 3	Black Dog 3, Black Dog 4, King 1, Minnesota Valley 3, Riverside 8, Sherco 1, Sherco 2, Sherco 3
Regulatory Description	Cap-and-Trade, maintain sufficient allowances to cover emissions from affected units	Each affected unit shall propose to employ the technology most likely to achieve 90% reduction	Each affected unit shall install MACT (to achieve 90% reduction)
Compliance Timeline	Phase I in 2010 (national cap of 38 tons), Phase II in 2018 (national cap of 15 tons)	Install controls on one dry scrubbed unit by 12/31/2009, install controls on 2nd dry scrubbed unit by 12/31/2010, install controls on wet scrubber units by 12/31/2014	Install MACT controls by regulatory deadline (expected by 2010)

Q. YOU HAVE DISCUSSED THREE MERCURY REDUCTION REGIMENS. ARE THERE ANY IMMEDIATE DIFFERENCES IN FINANCIAL IMPACTS THAT RESULT FROM THESE REQUIREMENTS?

A. No. The mercury control technology selected for compliance with CAMR, MMERA, or MACT is basically the same. In general, a sorbent injection system would be used to remove 60 to 90 percent of the mercury emitted from these units. Under CAMR, the Company planned on installing mercury controls on Sherco 3 in 2009 and on King 1 in 2010 and maximizing mercury control on these units to meet our annual allowance allocation. Additional controls or allowance purchases will be required by 2018 to comply with the second phase of CAMR when the allowance allocations are reduced. Under MMERA, the Company is required to propose to employ the available technology for mercury removal that is most likely to result in the removal of 90 percent on Sherco 3 and King 1 by December 31, 2009 for one unit and by December 31, 2010 for the second unit. MMERA also requires the Company to propose to employ the available technology for mercury removal that is most likely to result in the removal of 90 percent on Sherco 1 and 2 by December 31, 2014. While the MACT rule has not been published, the requirements of MACT are expected to require 90 percent (or higher) removal from all coal-fired units greater than 25 MW, including King 1, Sherco 1, 2 and 3, as well as the other coal-fired units in our system.

As stated above, a sorbent injection system would be used to remove 60 to 90 percent of the mercury emitted from each of these units. Therefore, the capital costs for a mercury removal system to satisfy the MMERA, CAMR or a Federal

MACT standard would be all the same. Additionally, those capital costs are not included in the current test year for this proceeding.

Q. WHAT DO YOU CONCLUDE WHEN COMPARING MINNESOTA'S ENVIRONMENTAL STANDARDS TO THE FEDERAL STANDARDS?

A. For all emissions except for mercury, Minnesota's standards are consistent with Federal standards. For mercury, Minnesota's current emission standards are actually less restrictive than the soon-to-be-implemented Federal standards. Further, there is no current difference in financial impact on customers, regardless of which requirement is considered.

Q. PLEASE COMMENT ON MR. KING'S PROPOSAL TO DISALLOW $268,000 BASED ON THE ASSUMPTION THAT THE COMPANY IS SPENDING THAT AMOUNT TO COMPLY WITH A HIGHER MINNESOTA STANDARD.

A. As I have indicated, the same technology will be used to meet any mercury standard – Federal or state; thus the costs of implementing a mercury control system is the same under either requirement. The primary difference in cost due to the MMERA will be the amount of sorbent injection needed to meet the standard. However, those costs are not included in the 2008 test year budgets as they are future O&M costs that will be incurred after implementation of the projects.

The only additional cost in 2008 used to meet Minnesota requirements is the $12,335 for monitoring mercury emissions. These are necessary compliance costs, and the information provided through monitoring is useful to the

Company in designing and managing future state and Federal compliance efforts for mercury.

III. MERP

Q. PLEASE DISCUSS THE ENVIRONMENTAL COMPLIANCE BENEFITS ACCRUING FROM THE COMPANY'S MERP PROJECTS AT THE KING, HIGH BRIDGE AND RIVERSIDE PLANTS.

A. The MERP projects provide a number of benefits. First, because the program met Best Available Control Technology ("BACT") for SO_2, NOx and particulate matter ("PM"), it significantly reduces the risk of additional environmental improvements that would have been required with any future plant activities. For example, Company environmental staff regularly reviews proposed plant projects to determine if a project results in emissions increases that would trigger New Source Review ("NSR") requirements. One of these requirements is the installation of BACT. Because of the uncertainties associated with the NSR program, any improvement project has the risk of triggering NSR requirements. If an environmental regulator disagrees with our determination of whether a project triggered NSR, that project would then have to go through the full NSR process, including the installation of BACT. If a plant already has BACT, the potential financial and operational risk is much lower than for a facility without BACT in place.

Second, the projects will lower emissions of all pollutants. The MERP facilities were consistently on the list of the five highest emitters in Minnesota. As a result, they were subject to high environmental regulatory scrutiny.

Third, the rehabilitated or new facilities will be more efficient generators of electricity. As a result, these units will have lower emission rates per unit of energy produced, typically measured in pounds per megawatt-hour (lb/MWh).

Finally, MERP activities, specifically at gas-fired plants, eliminate the fugitive dust issues associated with coal handling, ash handling and coal trains.

Q. ARE THE EMISSION REDUCTIONS IMPLEMENTED THROUGH MERP CONSISTENT WITH FEDERAL STANDARDS?

A. Yes. The MERP projects have prepared us well for compliance with Federal rules and regulations that have since been implemented. Since the Company's MERP proposal was proposed and approved, the following new environmental regulations have been adopted:

- Clean Air Interstate Rule (CAIR) – Federal rule (May 2005),
- Clean Air Mercury Rule (CAMR) – Federal rule (May 2005) [vacated in February 2008],
- BART Determinations under the Regional Haze Rule – Federal rule (July 2005),
- Minnesota Mercury Emission Reduction Act of 2006 – Minnesota Law (May 2006).

Of these rules, CAMR and MMERA regulate mercury emissions in an effort to reduce the human health impacts from these emissions. As discussed above, the soon-to-be-implemented Federal rules addressing mercury emissions will exceed the vacated CAMR requirements. The CAIR and Regional Haze rules regulate emissions of SO_2 and NOx in an effort to reduce health impacts from formation

of ground-level ozone from NOx emissions and fine particulate matter ($PM_{2.5}$) from SO_2 and NOx emissions.

As a result of the MERP projects, Xcel Energy is now well positioned to comply with these rules. For example, when completed, the MERP projects will reduce NOx emissions by over 20,000 tons per year and SO_2 emissions by over 30,000 tons per year. Absent MERP, Xcel Energy would have needed to propose additional NOx and SO_2 emission reduction projects of at least those amounts to comply with these Federal rules.

The Company also would have needed to implement mercury emission reductions at the MERP facilities had the MERP retrofits and replacements not taken place. Of the three MERP facilities, only the King Plant will require installation of mercury controls under state and Federal rules. By converting the High Bridge and Riverside Plants to natural gas plants, we have removed these units from being subject to the state and Federal mercury rules, thus avoiding the cost of complying with mercury requirements at the High Bridge and Riverside Plants. As I discuss below, it has been our experience that the cost of acquiring the necessary technology is significantly higher if it is implemented after the standards take effect.

Q. MS. ENGELKING'S REBUTTAL TESTIMONY DISCUSSES THE DIFFULTIES OF PERMITTING THE COAL-BASED REPOWERING ALTERNATIVE FOR THE HIGH BRIDGE PLANT. CAN YOU PROVIDE ADDITIONAL DETAIL ON THIS?

A. Yes. As discussed by Ms. Elizabeth Engelking, we considered a coal-based option when evaluating our MERP proposal. Continued use of coal at this

facility would have entailed higher levels of almost all emissions, including mercury, SO_2, NOx, particulates, and fugitive dust associated with coal and ash handling. Although a coal option was considered, it was not a practical long-term option for this location. The High Bridge facility is located in the center of a densely populated urban environment. In general, communities throughout the country are no longer comfortable with these types of facilities located within their urban cores. This general resistance was reflected by the MPCA in its evaluation of the coal option at this site. As discussed in Ms. Elizabeth Engelking's Rebuttal Testimony, initially, the MPCA rejected our coal alternative plan for High Bridge as not satisfying the EPA BACT requirements. While the MPCA modified its position on whether the coal alternative would satisfy the relevant EPA and MPCA pollution requirements, it concluded that keeping the plant on coal was not the most cost effective way to proceed. This contrasts with our experience at the King facility, where the issues associated with coal-fired generation in a densely populated urban environment were not present.

Q. IN WHAT WAYS WERE THE COMPANY'S MERP PROGRAM CONSIDERED COST-EFFECTIVE COMPLIANCE WITH ENVIRONMENTAL REGULATIONS?

A. The Company's MERP program resulted in significant emission reductions from the MERP facilities. The MPCA addressed the question of cost-effectiveness from an environmental perspective in their review of the proposal. First, they applied the test of cost-effectiveness in the manner prescribed for completing a BACT analysis. The MPCA concluded that the midpoint of the range of cost per ton of pollutant removed from the primary MERP proposal was $688 per ton, while that for the Alternative Project was $830 per ton. At the time the project was reviewed, the MPCA stated that "Generally, pollution controls are

found to be cost-effective, unless their cost exceeds $6,000-$10,000 per ton of pollutant removed, depending on the pollutant be evaluated."[1] Second, the MPCA concluded in their review of the MERP projects that the quantified benefits of the project are equal to or likely to exceed the project cost.[2] This determination was made by looking at a combination of externality values and health effects information. From this information alone, the case can be made that the projects were cost-effective.

As indicated earlier in my testimony, the MERP projects have positioned us for compliance with Federal rules and regulations that were not proposed at the time the MERP project was being developed, specifically CAIR. The CAIR allocations of NOx for the King, High Bridge and Riverside plants total 5,881 tons per year. To achieve this level of emissions, these three plants combined would have needed to reduce their annual NOx emissions by over 20,000 tons per year or to obtain enough NOx allowances on the open market to cover this 20,000-allowance shortfall. Using allowance cost data from trade publications, this shortfall equates to $52 million to $96 million per year in allowance purchase costs, assuming prices of $2600 to $4800 per allowances for 2009 and 2010 vintage NOx allowances. In comparison, the King NOx control device cost on the order of $60 million, roughly equivalent to a single year of allowance purchases. From this perspective, the emissions reductions for NOx compliance alone are very cost-effective.

[1] Minnesota Pollution Control Agency Supplemental Comments at the October 2, 2003 Information Meeting on the Xcel Energy Metropolitan Reduction Project, at page 3, filed October 23, 2003 in MPUC Docket No. E002/M-02-633. Available at http://www.pca.state.mn.us/publications/reports/xcel-metroreductionproject.pdf

[2] *Id.*

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE COMPANY'S MERP PROGRAM.

A. It is clear that the Company's MERP program did not result in over-compliance compared to Federal emission standards. Rather, the emission compliance activity implemented through MERP resulted in cost-effective compliance with Federal emission requirements. The benefits of this progressive strategy will be discussed in detail below. Further, the Company's strategies at King, High Bridge and Riverside were designed to meet the specific needs of each location, resulting in gas-fired generation in a densely populated location and coal generation in a location more removed from an urban center.

IV. BENEFITS OF XCEL ENERGY'S ENVIRONMENTAL STRATEGY

Q. WHAT IS THE COMPANY'S ENVIRONMENTAL STRATEGY?

A. Xcel Energy's strategy is to anticipate changing environmental requirements and implement effective technologies that will allow us to reduce emissions and risk in a prudent and planned manner.

Q. WHY HAS THE COMPANY FOUND IT COST-EFFECTIVE TO ANTICIPATE ENVIRONMENTAL REQUIREMENTS?

A. We find that by anticipating environmental requirements, we improve our ability to plan and budget, rather than to simply react to each regulatory requirement. For instance, the former NSP carefully investigated the benefits of switching from Illinois bituminous coal to low sulfur western coal in the 1970's and 1980's, and, as a result, made that switch. By adopting this technology shift early on, we were much better positioned for the Clean Air Act Amendments of 1990. These

types of approaches enable us to better plan and budget for upcoming regulatory programs.

Another example of anticipating environmental requirements is the addition of NOx controls prior to Phase II of the Acid Rain Program. By installing low NOx burner ("LNB") technology on Unit 2 at the Sherburne County Generating Plant and overfire air ("OFA") technology at the King Plant prior to the regulatory due dates, the Company was able to comply with these provisions with minimal expenditures across the rest of the coal plant fleet. This use of a system NOx averaging approach provided a substantial economic benefit to our customers when compared to installing NOx controls on each coal-fired unit in our system.

Finally, and most relevant to this proceeding, the Company proactively implemented emission improvements through MERP that, as described above, resulted in cost-effective compliance with Federal emission requirements.

Q. WHY WAS EARLY IMPLEMENTATION OF EMISSION REDUCTIONS THROUGH MERP SUPERIOR TO A WAIT-AND-REACT APPROACH TO EMISSION COMPLIANCE?

A. I believe that a wait-and-react approach would have significantly raised compliance costs. Several major problems would have been encountered had we waited, including:

- Scheduling all of the required outages in a short period of time,
- Arranging engineering services for all of these projects while the rest of the utility industry is engaged in the same activities,

- Allocating capital for pollution control equipment over this short period of time without getting any additional generation capacity with these projects, and
- Payment of higher prices for the materials and services because of higher demand and shortened planning windows.

In short, absent MERP, the emission reductions that ultimately would have been implemented would have required significant expenditures with none of the benefits discussed by Ms. Engelking in her Rebuttal Testimony. This is the clearest example of the benefits of foresighted compliance with emission standards.

Q. WILL THE COMPANY CONTINUE TO IMPLEMENT A STRATEGY OF PROACTIVE COMPLIANCE WITH REGARD TO EMISSION COMPLIANCE?

A. While it is not the Company's intent, nor is it possible to anticipate every new environmental compliance requirement, we do believe that a continued proactive approach is merited. Thus far, our strategy has provided significant financial, operational and environmental benefits to our customers. An example of these significant benefits to our customers is the NOx reduction strategy for compliance with the CAIR allowance program. As I explained earlier, our installation of NOx controls at the King Plant, together with the conversion to natural gas at High Bridge and Riverside, provides savings of between $52 million to $96 million per year in avoided allowance purchase costs. Our customers will continue to benefit each year from these avoided compliance costs and the reduced emissions to our environment. We will continue to

carefully monitor environmental regulatory activity and initiatives, so that we can make prudent emission compliance decisions on behalf of our customers.

V. SUMMARY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. Xcel Energy's environmental strategy is to anticipate changing environmental requirements and implement effective technologies in a prudent and planned manner. Our customers have and will continue to benefit from this approach. Furthermore, while anticipating changing environmental requirements, we have not over-complied with air- quality standards. The appearance of over-controlling mercury emissions in Minnesota is a temporary issue that will be resolved with final mercury standards. Finally, the MERP program has proven to be consistent with our efforts to anticipate and cost-effectively respond to changing environmental regulations.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

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

AFFIDAVIT OF
Richard A. Rosvold

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.

Richard A. Rosvold

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

Notary Public

JUDITH FROEMMING
NOTARY PUBLIC – MINNESOTA
MY COMMISSION EXPIRES 1-31-2010