EXHIBIT
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Direct Testimony and Schedules
Stephen J. Beuning

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-____
Exhibit 12

Recovery of Costs Associated with the
Midwest Independent System Operator

December 7, 2007

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION

A. My name is Stephen J. Beuning. I am employed as the Director of Market Operations for Xcel Energy Services Inc., the service company for Xcel Energy Inc. In this position, I am responsible for the relationship between the wholesale electric trading organization for the Xcel Energy utility operating companies and the various regional transmission providers and market operators. My resume is included as Exhibit __ (SJB-1), Schedule 1.

Q. FOR WHOM ARE YOU PROVIDING TESTIMONY?

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

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My Direct Testimony provides background on the Midwest Independent System Operator ("MISO") and makes recommendation for the recovery of MISO costs. I provide testimony explaining that the benefits from MISO operations justify the recovery of certain MISO administrative costs. These costs are described as MISO Schedule 10 (and its related components), and Schedules 16 and 17, under the Transmission and Energy Markets Tariff of the MISO, a rate schedule on file with the Federal Energy Regulatory Commission ("FERC"). Further, I support the recovery of those charges in base rates on a prospective basis, and explain why the present method of recovering MISO Schedules 16 and 17 costs in the fuel cost adjustment should not be subject to refund.

II. BACKGROUND

Q. PLEASE SUMMARIZE XCEL ENERGY'S RELATIONSHIP WITH MISO.

A. Of the Xcel Energy utility operating companies, the Company and Northern States Power Company, a Wisconsin corporation ("NSPW") are members of MISO. I will refer to them collectively as the "NSP Operating Companies." The NSP Operating Companies operate an integrated electric generation and transmission system and a single electric control area certified by the North American Electric Reliability Council ("NERC"). Within its regional footprint, MISO is responsible for providing transmission services, acting as NERC regional reliability coordinator and operating a regional energy market. FERC conditioned approval of the merger of the former Northern States Power Company with New Century Energies, Inc. ("NCE") on the NSP Operating Companies joining MISO.

Our relationship with MISO is that of a transmission-owning member of MISO under the MISO Owners Agreement, a rate schedule on file with FERC.[1] We participate in MISO's stakeholder processes individually and as part of the Transmission Owner sector, collaborating primarily with other vertically-integrated Transmission Owners ("VITOs"), to work with MISO and other market participants in development of policies and operational standards. We are a market participant and network integration transmission service customer within the MISO regional energy market. We are also an

[1] The full name of the owners Agreement is the "Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc., a Delaware Non-Stock Corporation," contained in the MISO FERC Electric Tariff, First Revised Rate Schedule No. 1.

active advocate within MISO and various stakeholders groups for policies that will benefit our portion of the Midwest region and our customers.

Q. PLEASE DESCRIBE THE MISO REGIONAL ENERGY MARKET.

A. The MISO regional energy market performs a reliability-based economic dispatch from a portfolio of approximately 130,000 MW of generation to serve a peak demand of approximately 113,000 MW of end use load. The selection of generators is based on a least-cost security-constrained dispatch. The regional market uses a "two-settlement" system where participants make binding day-ahead financial commitments and then settle any deviations from their day-ahead commitments in a real-time balancing market. The MISO market also uses Financial Transmission Rights to hedge participants' exposure to congestion costs in the day-ahead market.

Prior to the start of the MISO regional energy market, each utility or control area performed localized economic dispatch of its own resources to meet its loads. During a given period (*e.g.* an hour, day, month or season) a utility might find itself with more resources than demand. In such periods, the utility would generally attempt to sell the unused resource through a bilateral transaction with another utility or a wholesale marketer. However, there was no organized market to facilitate these transactions overall, so market efficiency was not optimal.

Also prior to start of the MISO regional energy market, transmission system delivery rights were granted such that all prior requests for similar service priority levels could be accommodated. To preserve the ability to honor prior service requests the transmission providers used conservative methods to evaluate grid impacts. In particular, transmission providers used inflexible dispatch assumptions in their models. Unfortunately, prior to the MISO market, when a new transmission service request could have been accommodated by flexible generation dispatch the transmission provider had no method to coordinate the dispatch changes, no method to account for the fuel expense and energy credits and no method to bill the transmission customer for any flexible dispatch response. Pre-market access to the power lines was a first-come-first served method with limited options.

Since implementation of the MISO regional market in April 2005, the grid operation has evolved to an optimization of energy supply and transmission usage. Because MISO has direct dispatch control and selects supply offers from each generator on a least-cost basis, it is able to perform an overall regional energy supply optimization. In turn, the use of the power lines is enhanced through MISO's ability to perform economic dispatch to manage congestion up to the reliability limits of the wires. This permits economic dispatch optimization of the regional generators.

The pre-regional market transmission service request evaluation methods retained historical physical rights for each utility and frequently denied incremental access to new entrants. In contrast, the present MISO market-based network service method permits full access to the wires within reliability-based limits. This regional economic dispatch provides flexibility in transmission services and increased access to the grid. Further, it provides a method to properly allocate the costs of flexible generation dispatch to the incremental users of the system.

This feature of flexible access was not available prior to the MISO market and many requests for increased transmission service were simply denied. The MISO uses software, hardware and human resources to operate this regional market. Schedule 17 of the MISO Transmission and Energy Market Tariff ("TEMT") recoups the MISO market operation costs for this hardware, software and staff.

The market-based network service method also permits hedges against the cost of flexible generation dispatch in the regional market. The method by which modern regional markets, including MISO, confers a hedge against the costs of flexible dispatch is through use of Financial Transmission Rights ("FTRs"). Another term used for the flexible generation cost component is congestion cost. The FTRs are a tool that rebates congestion costs to parties with long-term rights for grid use or who have procured the FTR rights in a regional auction. The MISO uses software, hardware and human resources to manage the allocation and auction of FTRs in the regional market. Schedule 16 of the MISO TEMT recoups the MISO FTR administration costs for this hardware, software and staff.

Lastly, I would like to address the MISO tariff Schedule 10. MISO performs ongoing basic services that began even prior to the regional LMP market. An example of this ongoing service includes Reliability Coordination, a role established in compliance with the reliability standards of the North American Electric Reliability Council ("NERC"). Further the basic costs for MISO offices, general administration and coordination of MISO transmission service planning and tariff administration are recovered through Schedule 10 and its related components. It would be fair to say that without the infrastructure and services supported by Schedule 10 there could not be the regional energy market, which, in turn, is provided through the additional infrastructure and services supported by Schedules 16 and 17.

A. Regional Market Benefits

Q. WHAT BENEFITS DOES THE MISO REGIONAL MARKET PROVIDE TO RATEPAYERS?

A. Ratepayers derive benefits from the following aspects of the MISO regional market design:

1. Reduced energy costs to ratepayers from a broad and efficient centrally dispatched market;
2. More efficient use of limited transmission resources;
3. Reduced redispatch costs and improved reliability, due to MISO's ability to observe regional grid conditions and selectively redispatch generators in response to reliability concerns;
4. MISO's role in consolidation of contingency reserves, resulting in increased efficiency;
5. Enhanced generation dispatch integration of intermittent renewable resources such as wind generators;
6. Long-term regional grid and generator planning benefits, meaning an improved ability to locate potential transmission and generation additions that can provide the greatest benefits to customers; and
7. Improved reliability coordination and other regional services from MISO compared with predecessor organizations.

Q. HAS THE MISO REGIONAL MARKET DELIVERED THESE BENEFITS?

A. Yes. Our experience to date shows direct benefits from participation in the MISO regional market. There were implementation issues during the start-up period for MISO, the Company, and other market participants that resulted in additional costs or provided some unexpected results. However, based on our experience to date, I believe there are solid indicators that the MISO regional market delivers these benefits. Also the benefits of the regional market - and thus the savings for our customers - should increase as MISO implements plans for its Ancillary Service Market design (scheduled for startup in 2008).

1. Reduced Energy Costs

Q. LET'S WALK THROUGH EACH OF THE BENEFITS. WHAT IS YOUR ASSESSMENT OF MISO'S ABILITY TO DELIVER LOWER ENERGY COSTS DUE TO THE CENTRALLY DISPATCHED SYSTEM?

A. As both the regional grid operator and regional market operator, MISO uses its knowledge of grid conditions combined with the energy supply offers of all market participant generators to achieve a cost-optimized dispatch solution that respects the reliability constraints of the grid. Prior to the regional market this level of insight and coordination was unattainable despite decades of effort in that direction through organizations such as the Mid-Continent Area Power Pool ("MAPP").

To illustrate this benefit, let me provide an example that occurred during the first six weeks of regional market operations. The regional market began during spring conditions when many utilities schedule their generator outages to perform maintenance. At the start of MISO's market operations, approximately 29,000 MW of regional generation was out of service for maintenance or due to forced-outage conditions (out of a total of approximately 130,000 MW in the MISO region). Based on my experience with transmission operations, I believe that - without the regional market - these outage levels would have resulted in significant non-firm and even firm Transmission Loading Relief ("TLR") curtailments under the pre-market operating procedures. Both would have required the Company to engage in out-of-merit order purchases or generation redispatch at higher energy costs. However, no significant disruptions occurred; instead, MISO was able to deliver needed resources to regional loads during this very challenging set of operating conditions.

Similarly, during December 2005, the Red River Valley experienced major transmission outages due to ice storms. The MISO regional market redispatch ensured continued energy supply to NSP Operating Companies customer loads while managing the grid reliability.

In general, the NSP Operating Companies benefits from the expanded market purchase opportunities offered by MISO's day-ahead and real-time markets. To summarize the benefits of the regional market, Exhibit_ (SJB-1), Schedule 2 provides an excerpt from an analysis performed by ICF Consulting on behalf of MISO indicating their progress towards capturing the maximum theoretical benefits available to the region. This analysis indicates that for the period from April 2006 through August 2006, MISO achieved actual economic dispatch benefits at an annual rate of $139 million per year for the period out of an estimated achievable annual benefit rate of $206 million for the current market structure.

2. More Efficient Use of Limited Transmission Resources

Q. PLEASE DISCUSS THE SECOND BENEFIT YOU ANTICIPATED PRIOR TO THE START OF THE DAY 2 MARKET, THE MORE EFFICIENT USE OF LIMITED TRANSMISSION RESOURCES.

A. The Company has been able to make more cost-effective purchases of both capacity and energy due to the regional market because MISO is making better use of available transmission resources than existed during pre-market operations. This is due to MISO having dispatch control over such a large footprint, allowing transactions to occur that would not have been possible under the more conservative access policies and lack of redispatch control that existed pre-market. First off, for capacity purchases, MISO evaluates the grid's ability to accommodate the dispatch of all network resources, which opens access to potential capacity resources that were not considered "deliverable" prior to the market. This has resulted in improved access to purchased capacity resource options for the NSP Operating Companies. Secondly, regional dispatch has provided increased energy spot market transmission access, resulting in an improved ability for the Company to make cost-effective energy purchases. Both aspects demonstrate increased grid access obtainable due to the regional market.

3. Reduced Redispatch Costs and Improved Reliability

Q. LET'S TURN TO THE THIRD AREA OF BENEFITS FROM THE REGIONAL MARKET. HAVE YOU SEEN LOWER REDISPATCH COSTS IN THE NEW MARKET ENVIRONMENT?

A. Yes. First, the regional market offers a significant economic improvement over the pre-market, inefficient, "share-the-pain" TLR process. My Exhibit __ (SJB-1), Schedule 3 compares the process for transmission transaction curtailments under TLR with those under the regional market approach. Under the pre-market TLR process, MISO might need to order curtailment (and thus redispatch) of hundreds of MW of transmission service transactions to reduce the loadings on a specific element on the regional grid by a few MW.

Under the regional market, MISO can direct specific changes in the generation pattern to protect the specific element, thus reducing our need to redispatch. The economic benefits of "rifle shot" regional market redispatch versus the pre-market "shotgun" TLR processes are substantial, in my opinion. Further, TLR curtailment directives would typically take from 30 to 60 minutes to implement, whereas the MISO economic dispatch systems can order a response in the next five minute MISO dispatch cycle, so reliability is also enhanced.

Second, the regional market provides reliability benefits in terms of serving load within the Company's control area because of loss of generation. To illustrate this point, let me state how redispatch occurred under pre-market operations. If we were to suffer a major resource loss in our control area on a peak day, we typically had only local redispatch alternatives to meet the Company's reliability obligations under NERC procedures, as there were limited transmission paths available to import replacement energy and limited ability to evaluate redispatch effects using non-local resources. For example, if Sherco 3 suddenly tripped off-line because of a forced outage, the Company would need to rapidly ramp up other generators to meet load in the control area. That redispatch could be expensive to implement, and the additional fuel costs would flow through the Fuel Cost Adjustment ("FCA") account. In addition, if the emergency dispatch caused an overload condition on a transmission element on a neighboring transmission system, MISO in the pre-market environment (and previously MAPP) would initiate a TLR curtailment, which could require us to initiate further changes to the dispatch regime to reduce the impact on the constrained element and further increase the cost to our customers. By comparison, the regional market can clear the most efficient resources to replace the output of a unit experiencing the forced outage, allowing us to quickly replace energy from the lost unit at the lowest available cost.

Q. DO YOU SEE EVIDENCE OF IMPROVED RELIABILITY UNDER THE REGIONAL MARKET?

A. Yes. As I discussed earlier, the early months of regional market operations presented very challenging dispatch conditions, given the large number of generating units that were out of service for maintenance or forced outage. Based on my experience, such a situation would likely have resulted in firm service curtailments in a pre-market operating environment. Moreover, while MISO cannot entirely eliminate all risks of load-shedding events or blackout, it has the tools and methods needed to reduce the risk of these situations occurring due to energy shortfall conditions. By controlling dispatch over such a large footprint, MISO offers greater reliability than the prior MAPP or MISO pre-market environment.

4. MISO's Role in Consolidation of Contingency Reserves

Q. WHAT BENEFITS DID MISO PROVIDE WITH REGARD TO CONTINGENCY RESERVES RELATED TO THE REGIONAL MARKET?

A. Prior to the regional market, the utilities in the MISO region participated in three geographically distinct generation reserve sharing groups. They were: the MAPP, the Mid-American Interconnected Network ("MAIN") and the East Central Area Reliability Council ("ECAR"). But for the existence of the MISO regional market, these generation reserve sharing groups would have continued their past practices of allocating contingency reserves based on their own criteria as sub-regions in the MISO footprint. However with the situational awareness available to MISO based on its regional grid oversight tools, MISO facilitated the consolidation of these groups into a single entity for generation contingency reserve-sharing. The new group, called the Midwest Contingency Reserve Committee ("MCRC"), began operations on January 1, 2007.

Similar to the concept of an insurance pool, the increased number of participants in the MCRC has allowed a reduction in the "insurance premiums" of the participants. In the case of generation reserve sharing, this means that each utility participant has been able to reduce the amount of ready-reserve generation held in standby mode. This translates directly to energy production cost savings by increasing the resources available for basic energy dispatch.

MISO has been tracking the regional production cost savings due to the MCRC since its inception. In their December 2007 monthly operations update materials, MISO documents year-to-date savings of $85.7 million for the region in energy production costs due to implementation of the MCRC. (Source: Midwest ISO Market Operations Report, November 2007, available from the Midwest ISO web site at www.midwestmarket.org.)

5. Enhanced Generation Dispatch Integration of Intermittent Renewable Resources Such as Wind Generators

Q. HOW DOES THE MISO REGIONAL MARKET PROVIDE BENEFITS FOR INTEGRATION OF RENEWABLE RESOURCES SUCH AS WIND GENERATORS?

A. Prior to the MISO regional market when a renewable generation resource (for example, a wind energy farm) located within a local utility balancing area, that utility was required to keep generation resources set aside to assure it could continue to balance generation and load – a fundamental requirement of utility grid operations. This remains a requirement of utility balancing areas within MISO today, but with a major change made possible due to the regional market. Recall that MISO performs a generation dispatch each five-minute interval. This results in "recalibration" of the regional generation dispatch to assure balance within the limits of very short-term variability of the wind farm output. Therefore the short term balancing component, termed "regulation," remains with each balancing area. But the regional dispatch now manages the longer-term variability of the wind farms. The beauty of this arrangement is that the regional market dispatch is based on economic offers from participating generators, so there is no "foul" or additional cost allocation requirement involved in the intermittent dispatch variability having been broadened over the entire MISO market region.

In 2004, the NSP Operating Companies completed participation in a groundbreaking analysis[2] of the operational impacts to its utility balancing area in a pre-market scenario of accommodating 1500 MW of wind resource in its footprint. In that study, the NSP Operating Companies determined that the cost as a stand-alone utility was approximately $4.60 per MWh of wind output.

Subsequent to the MISO regional market startup, the NSP Operating Companies and the other jurisdictional utilities in Minnesota performed an analysis of the impacts of accommodating 5000 MW of wind resources within Minnesota, but with the added regional dispatch feature as described above, where the intermittent dispatch variability is broadened over the entire MISO market region[3]. The analysis considered various levels of wind generator penetration in the region. All levels of generation penetration in this analysis were higher than the NSP Operating Companies' stand-alone analysis from 2004. Despite the increase in wind generation capacity, the study showed a reduction in the cost per MWh of wind output. This demonstrates a substantial benefit from the MISO regional dispatch and load-following capability.

At the lower range of wind penetration analyzed in the study, the consolidation of dispatch resulted in wind integration costs of roughly $2.55 per MWh of wind output. At the high range, with about 5000 MW of wind

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[2] Source: Xcel Energy and the Minnesota Department of Commerce – Wind Integration Study Final Report, at 134 (September 28, 2004). Report is available from the MN Department of Commerce or at the Utility Wind Integration Group (UWIG) web site at www.uwig.org.

[3] Source: Final Report – 2006 Minnesota Wind Integration Study Volume 1 (November 30, 2006). This report is available at the web site of the Minnesota Public Utilities Commission at www.puc.state.mn.us.

generation installed, the wind integration costs were projected at roughly $4.41 per MWh of wind output.

By the end of 2007, the NSP Operating Companies system is forecasted to have approximately 1150 MW of wind generation capacity owned or output purchased under contract. These resources will have produced approximately 2,000,000 MWh in 2007. Using this 1150 MW installed resource level, I estimate the difference in costs for the "go-it-alone" method of wind integration evaluated by the NSP Operating Companies in the pre-market study compared with the regional integration method and costs evaluated in the post-market study. The pre-market study at this level of penetration indicated approximately $4.60/MWh of wind. The regional market study at this level indicated approximately $2.55/MWh of wind. The difference multiplied by the 2007 estimated total wind energy production for the NSP Operating Companies indicates roughly $4,100,000 dollars saved through more efficient regional operations.

6. Long-term Regional Grid and Generator Planning Benefits

Q. PLEASE ELABORATE ON LONG-TERM PLANNING BENEFITS OF THE REGIONAL MARKET.

A. In one sense the regional market planning process is similar to pre-market methods, since fundamentals such as demand growth and specific generator additions are the fundamental drivers. But MISO's regional market permits additional information to be brought to bear on the decision analysis. In particular, areas with generation or load bottlenecks yield price signals that inform planners as to the relative merits among construction and site alternatives.

In addition, some areas of the grid have always been susceptible to loop-flow impacts due to grid interaction with external generators and loads. However, with the market price signal data, MISO can establish an objective basis for transmission cost allocation between areas. These attributes were not possible prior to the regional market. MISO is presently negotiating with external utilities to establish an equitable loop-flow coordination cost allocation process.

7. Improved Reliability Coordination From MISO Compared with Predecessor Organizations.

Q. PLEASE DISCUSS IMPROVEMENTS TO RELIABILITY COORDINATION SINCE MISO BEGAN ITS OPERATIONS.

A. Prior to MISO startup, there were three Reliability Coordinator ("RC") entities in the footprint now covered by the market. (They were the MAPP, MAIN and ECAR.) The main features that distinguish MISO from predecessor RCs are its scope and tools that augment its situational awareness. The scope of the MISO RC function covers nearly all of the three predecessor regions. The tools to maintain situational awareness include a nexus of real-time operational data from all participants that permits MISO to evaluate threats to grid reliability and to select the most economic and reliable "course correction" to avert developing problems. The chief tool used by MISO is described as a state-estimator with a security analysis application used to evaluate the flow impacts on the grid for loss of remaining transmission grid elements. Prior to MISO, none of the predecessor areas had this level of sophistication coupled with generator cost information used to evaluate the best-cost methods to manage reliability.

As a side note, MISO performs some of the non-dispatch based RC functions for utilities that are not full MISO members but which subscribe to MISO for RC services. Those utilities pay their share of the MISO Schedule 10 costs associated with their receipt of RC services.

B. Financial Transmission Rights (FTRs)

Q. YOU MENTIONED THAT MISO ISSUED FTRS AS PART OF ITS REGIONAL MARKET IMPLEMENTATION. PLEASE DISCUSS THE PURPOSE AND BENEFITS OF FTRS.

A. MISO administers a process that allocates FTRs to help protect a market participant's historical rights to use the grid from the financial impact of the new regional market congestion cost method. This approach helps balance interests and keeps costs lower for all market participants. MISO allocates FTRs to the market participant based on their historical rights to grid use.

For example, the Company was allocated FTRs associated with deliveries from the Sherco station near Becker, Minnesota to our load centers in the Twin Cities Metropolitan Area and Fargo, North Dakota area. Similarly, where the Company had contracted for long-term transmission service to deliver purchased power, we were allocated FTRs. The FTR is a financial instrument that provides a form of "insurance" against the cost of congestion in the market footprint. MISO creates value by dispatching resources on the system over a large footprint, and FTRs attempt to keep historic users of the system financially indifferent if that dispatch results in higher congestion costs.

Beginning with 2008, MISO will make some modifications to the annual process they use for allocating FTRs. The new method employs Auction Revenue Rights ("ARRs") as a means for rights holders to obtain their FTRs. The end result for a utility that previously had been directly allocated FTRs may be identical, but the new allocation technique will assist in the proper financial valuation of new FTRs purchased by interested parties in annual auctions. This new ARR-based method for allocating FTRs enhances the existing allocation process. It places all participants on an equal footing for participation in the regional FTR procurement process.

Q. IS THIS THE ONLY BENEFIT OF FTRS?

A. No. I believe FTRs provide significant financial protection for our customers if a catastrophic event disabled numerous transmission facilities. Under the FTR process, FTR holders share the financial impact of a shortfall in revenues to fund FTRs, rather than having the entire congestion cost shouldered by the local system impacted by the catastrophe. The pro rata reduction in FTR funding payments during extreme conditions can act as a financial buffer during abnormal grid operations.

For example, if our system were to experience another storm similar to the one on June 24-25, 1998, when several major transmission lines in our control area were damaged by a series of tornadoes and severe storms and were out of service for several days or weeks, the congestion cost of the transmission outage would be shared over a broad region rather than borne mostly by our customers. The value of this congestion cost "insurance" is difficult to quantify in advance.

If the grid operates without unusual or extreme abnormal conditions during the year, some funds collected due to congestion costs on the grid may be in excess of the payments due to holders of FTR rights. In this circumstance, MISO rebates the "overcollection" of congestion revenues to the market participants.

C. Cost of MISO Operations

Q. YOU DISCUSSED THE BENEFITS OF THE MISO REGIONAL MARKET. LET'S TURN TO THE COSTS ASSOCIATED WITH IMPLEMENTATION OF THE MISO REGIONAL MARKET.

A. To operate the day-ahead and real-time markets and to administer the allocation and settlement of FTRs, MISO has incurred developmental and administrative costs that must be recovered from market participants. These administrative costs are collected through two MISO tariff schedules: Schedules 16 and 17. In addition, the costs of basic MISO services that would be incurred even without a regional market, such as reliability oversight, transmission tariff administration and planning are recovered through MISO tariff Schedule 10 and its related components.

Q. ARE THERE OTHER COSTS ASSOCIATED WITH THE REGIONAL MARKET?

A. Yes. We have incurred costs to operate in a regional market environment. For example, we added staff and implemented new information systems that allow us to communicate with the MISO market systems. We also implemented a system to "shadow" MISO's settlement statements and invoices to verify they are correct. These additional capital and operating costs are reflected in our budget.

Also, the Company, MISO and other market participants have encountered initial implementation issues that have affected costs during the start-up period. These include both operational actions by MISO and actions taken by the Company based on an imperfect understanding of regional market processes or requirements. As time progressed, we learned how to limit exposure to certain costs, and Xcel Energy has been an active participant in stakeholder forums to resolve implementation issues. For example, as a result (in part) of Xcel Energy's efforts, MISO announced on October 13, 2005, that it would modify its Revenue Sufficiency Guarantee ("RSG") calculation methodology to improve the accuracy of the RSG uplift charges. These actions will enhance the future benefits of the regional market to our customers.

D. Cost-Benefit Comparison

Q. WHAT CONCLUSIONS CAN YOU DRAW REGARDING THE RELATIVE COSTS AND BENEFITS TO THE COMPANY OF MISO'S REGIONAL MARKET?

A. Based on our experience with MISO, I believe the benefits of market participation outweigh the costs for the Company. Our analysis of benefits is corroborated by the cited ICF Study of MISO benefits for its entire regional footprint (my Schedule 2). Further, I believe the net benefits from MISO regional market will grow as MISO completes its anticipated Ancillary Service Market design.

Q. YOU HAVE DESCRIBED THE BENEFITS OF THE REGIONAL MARKET AND ITS RELATED FTRS AS WELL AS MISO'S BASIC TARIFF ADMINISTRATIVE AND RELIABILITY FUNCTIONS. SINCE XCEL ENERGY IS SEEKING RECOVERY OF MISO SCHEDULES 16 AND 17 AND SCHEDULE 10 IN BASE RATES, PLEASE DESCRIBE THE PURPOSE OF MISO SCHEDULE 16, SCHEDULE 17 AND SCHEDULE 10.

A. MISO Schedule 16 is used to recover the costs of administration of Financial Transmission Rights and associated Auction Revenue Rights pursuant to the MISO TEMT. Schedule 16 is levied as a charge against the sum of the MW portfolio of Financial Transmission Rights held by market participants times the rate of $0.0164 per MW-Hour. So for example if a market participant held 1 MW of financial transmission rights for an entire year, the charge would be 1 MW * 8760 Hours * $0.0164 per MWh = $143.66.

MISO Schedule 17 is used to recover the costs of administration of the day-ahead and real-time energy markets operated by the MISO. Schedule 17 is levied as a charge against the sum of MWh of injections from generators and withdrawals by loads that are settled by the market participant times the rate of $0.0749 per MWh. So, for example, if a market participant had 1MW of generation that served 1MW of load in all hours of the year, the charge would be (1MW + 1MW) * 8760 Hours * $0.0749 per MWh = $1,312.25.

MISO Schedule 10 is used generally to recover the costs of administration for MISO's transmission tariff, reliability coordinator functions, grid planning and standards development and market monitoring and compliance roles as well as non-market related overheads and expenses.

III. REGULATORY REVIEW OF THE COMPANY'S MISO PARTICIPATION AND COSTS

Q. HAS THE COMMISSION CONSIDERED AND DECIDED ANY CASES INVOLVING MISO AND RECOVERY OF MISO COSTS?

A. Yes. The Commission approved the transfer of the functional control of public utility transmission facilities to MISO in Case Nos. PU-400-00-91, PU-401-01-643 and PU-399-01-651 (January 31, 2002). Only Montana-Dakota Utilities ("MDU") has had a general rate case after the transfer – in Case No. PU-399-03-296 (December 18, 2003). Because the Commission approved a general rate increase for MDU approximately 11 months after the transfer of operating authority to MISO, I assume that the resulting Schedule 10 and related component charges are being recovered from MDU customers in base rates.

With respect to Schedule 16 and 17 charges, the only matter to come before the Commission has been whether Otter Tail Power ("OTP") should recover those charges through base rates or through the fuel cost charge. OTP was directed by the Commission, in its ORDER ADOPTING SETTLEMENT, Case No. PU-05-131 (August 8, 2007), to refund the Schedule 16 and 17 charges it had previously recovered through the fuel clause, but was allowed to defer those costs for possible recovery in base rates its next rate case, scheduled to be filed in November 2008.

Q. WHY DOES XCEL ENERGY PROPOSE TO RECOVER MISO SCHEDULES 16 AND 17 IN BASE RATES RATHER THAN CONTINUED RECOVERY IN THE COST OF PURCHASED POWER?

A. Initially the cost of the service was recovered though the fuel clause because it was considered as an adder to the cost of purchased power, since it is billed that way by MISO. However, we propose recovering our Schedule 16 and 17 charges, on a going forward basis, in our base rates based on: (1) the above described Commission action with respect to OTP, and (2) the fact that the volumes of load, generation and purchased power are fairly straightforward to forecast on an aggregated annual basis, making these costs amenable to base rate inclusion rather than as a variable expense associated with purchased power.

Q. WHAT ABOUT COSTS FOR SCHEDULE 16 AND 17 THE COMPANY HAS ALREADY RECOVERED THROUGH THE FCA; SHOULD THESE COSTS BE REFUNDED?

A. No. These are a prudent cost of doing business that the Company is entitled to recover. I note that OTP has been allowed to defer its Schedule 16 and 17 costs until its next rate case to be filed in November 2008. This rate case avoids the need for Xcel Energy to defer our Schedule 16 and 17 costs. To order the Company to refund prior billing of Schedule 16 and 17 with deferral for recovery in this current rate case would unnecessarily increase the amount of our rate increase, and would result in unnecessary mismatching of expenses to customer benefits.

Q. WHAT ARE THE 2008 FORECASTED EXPENSES FOR SCHEDULE 10 AND SCHEDULES 16 AND 17 FOR THE COMPANY?

A. The 2008-2009 forecasted expenses (North Dakota Jurisdictional Share) for Schedule 10 and its related components are $466,200. The forecasted expense for Schedules 16 and 17 is $522,300, as reflected in Ms. Anne Heuer's Direct Testimony.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. MISO has provided important and significant benefits to our customers by enhancing the operational efficiency and grid reliability of the MISO region. The costs incurred by the Company to support the regional market and its associated FTRs are prudent and reasonable and in the public interest. Therefore, the Commission should allow the Company to recover its full Schedule 10, 16 and 17 costs as established in this rate filing.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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-___

AFFIDAVIT OF
Stephen J. Beuning

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

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Stephen J. Beuning

Subscribed and sworn to before me, this 4 day of December, 2007.

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Notary Public

NANCY A. HALEY
NOTARY PUBLIC • MINNESOTA
MY COMMISSION EXPIRES
JANUARY 31, 2010

<u>Stephen J. Beuning</u>

Resume

Present Position: Director, Market Operations, Xcel Energy Services Inc.
(since April 2004)
In this position I provide leadership for energy supply and wholesale trading activity with staff engaged on behalf of the four Xcel Energy utility operating companies: Northern States Power Company, Northern States Power Company - Wisconsin, Public Service Colorado and Southwestern Public Service. Areas of responsibility include regional energy market design, regulatory and policy leadership in the areas of energy trading and ancillary services; energy supply contract analysis; and activity in transmission rights management for the business unit, including financial transmission rights. I provide operations leadership and support for wind integration issues.

I provide corporate representation for industry technical standards for Energy Market Design, Ancillary Services and Grid Congestion Management. I manage seams coordination and operational issues with Regional Transmission Organizations such as the Midwest Independent Transmission System Operator, Inc., the Mid-Continent Area Power Pool, the Southwest Power Pool, WestConnect, California ISO, the Independent Electric System Operator of Ontario and the Pennsylvania-New Jersey-Maryland (PJM) market.

Past Positions Include:
Manager, Transmission Operations, Xcel Energy Markets *(August 2001 – April 2004)*
Senior Operations Consultant, Xcel Energy Markets *(July, 1999 – August 2001)*
Transmission Services Project Manager, Northern States Power (NSP) (*March 1998 – July 1999)*
Director, Power Marketing, Cenerprise, Inc., a subsidiary of NSP (*March 1995 – March 1998)*
Wholesale Account Manager, NSP (*February 1993 - March 1995)*
Supervisor, Operation Coordination, NSP (*December 1991 - February 1993)*
Transmission System Operations Engineer, NSP (*June 1984 - December 1991)*

Education: Mini-Masters of Software Design and Development, an overview lecture series
St. Thomas University, Minneapolis, Minnesota, April 1999
Bachelor of Science in Electrical Engineering
University of Minnesota, June 1984

Professional Activity:

Chairman, Midwest ISO Operating Reserves Task Force; Chairman, Midwest ISO Readiness Metrics Task Force; North American Electric Reliability Council (NERC) Engineering Committee and NERC Standards Committee; Mid-Continent Area Power Pool (MAPP) Administrative Committee Vice-Chairman; MAPP Alternate Dispute Resolution Committee; Rocky Mountain Reserve Sharing Group participant; WestConnect project participant.

ICF Consulting Analysis of Actual Economic Dispatch Benefits Achieved By MISO for the Period From April 2006 Through August 2006

Exhibit 4-9(A)
Summary of Midwest ISO Benefits – April 2006 to August 2006

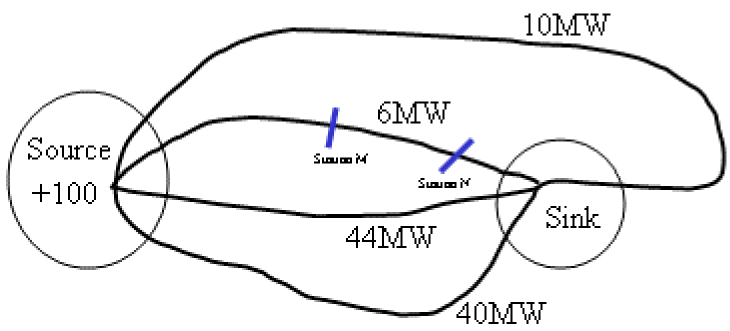
Category	Benefits ($million)	Annualized Benefits ($million)
Theoretical Maximum Potential Benefits	165	397
Estimated Achievable Benefits Given Current Market Structure	86	206
Actual Benefits Achieved	58	139

Source: ICF

Source: Addendum to the Independent Assessment of Midwest ISO Operational Benefits, May 1 2007 by ICF International. Posted on the Midwest ISO internet web site at www.midwestmarket.org.

Comparison of the Process for Transmission Transaction Curtailments Under TLR With Those Under the Regional Market Approach

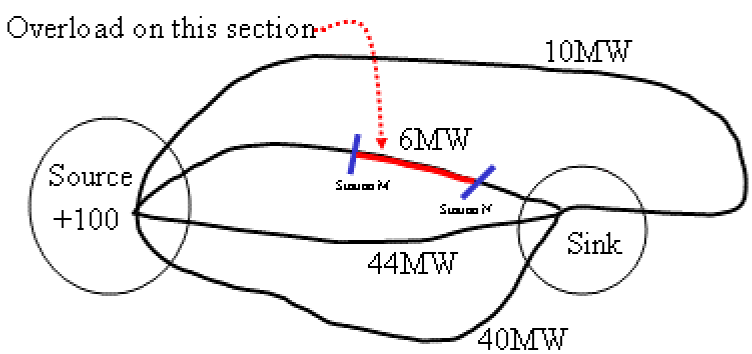
Power Delivery Across the Grid



Example: The 100 MW delivery from Source to Sink has a 6 MW of flow on line section from M-N. Power Transfer Distribution Factor (PTDF) = 6%.

i.e. Source-Sink PTDF line segment M-N = 6%

Delivery Contributes to Overload

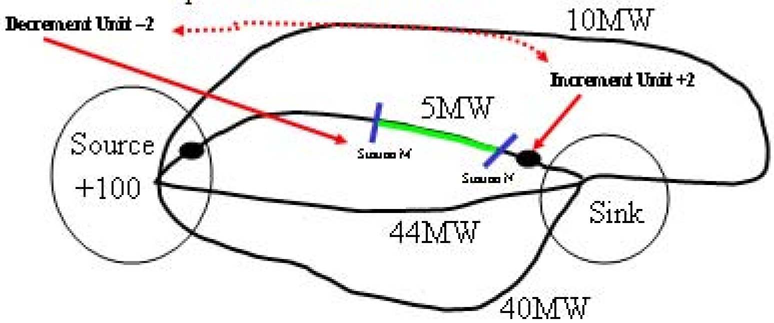


Assume overload requires 1 MW of relief on the Line M-N segment.

The NERC TLR procedure would require a transaction cut of the following: 1 MW relief / 0.06 PTDF = 17 MW cut to transaction.

What about Redispatch?

Redispatch alternative



<u>*Assume 50% PTDF from Incremental Unit to Decremental Unit.*</u>

Incremental unit +2 MW, Decremental unit -2 MW.

This provides 1 MW flow relief on Segment M-N and meets the curtailment obligation. **Inc-Dec GSF of -0.5 * 2 MW = -1 MW relief on M-N**

Economic Impact of TLR vs. Redispatch

- **Assume an economy energy hurdle rate of $2/MWH**
  - Then the example TLR transaction curtailment resulted in an economic impact of $34 per hour.
    - $34 loss = 17 MW curtailed * $2 margin
- **Assume an Incremental Unit cost of $50/MWH and a Decremental Unit savings of $45/MWH**
  - Then the redispatch alternative resulted in an economic impact of $10 per hour.
    - $10 cost = 2 MW * ($50 new cost - $45 savings)
- **The redispatch method is more efficient.**