Before the Minnesota Public Utilities Commission
State of Minnesota

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

Docket No. E002/GR-08-1065
Exhibit____

Benefits and Costs of MISO Participation

November 3, 2008
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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, a Minnesota corporation ("Xcel Energy" or the "Company").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?
A. My direct testimony provides background on the Midwest Independent Transmission System Operator, Inc. ("MISO") and recommends recovery of MISO costs. I provide testimony explaining that the benefits from MISO operations justify the recovery of Xcel Energy’s allocated share of 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 ("TEMT" or "Tariff") of the MISO, a rate schedule on file with the Federal Energy Regulatory Commission ("FERC"). I also

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1 The Xcel Energy Operating Companies include the Company, Northern States Power Company, a Wisconsin corporation ("NSPW"), Public Service Company of Colorado ("PSCo") and Southwestern Public Service Company ("SPS").

2 This includes Schedule 10-FERC and Schedule 24, which I discuss later in my testimony.
describe Company efforts to improve wind generation output forecasting and recommend recovery of costs related to those efforts. Lastly, I provide information on the recent evolution of regional standards for Resource Adequacy and our response to these developments.

I present my testimony in the following sections:

- Background
- Regulatory Review of MISO Participation and Costs
- Cost-Benefits of MISO Participation
- Wind Forecasting Improvements
- Wholesale Margins
- Purchased Capacity Costs/PPA Issues
- Summary and Conclusions

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS PROCEEDING.

A. Based on my analysis, I recommend that the Minnesota Public Utilities Commission ("MPUC" or the "Commission") allow the Company to recover all MISO administrative costs in the base rates established in this electric general rate case. I recommend that the Commission allow the recovery of deferred MISO administrative costs held since the last electric general rate case. I recommend the Commission allow the Company to recover certain costs associated with improved forecasting capability of wind energy resource output. I recommend treatment of wholesale margins to provide a credit from wholesale margins to our native customers in the Fuel Cost Adjustment ("FCA"). Finally, I recommend recovery of the test year purchased capacity costs.
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 Companies." The NSP Companies operate an integrated electric generation and transmission system (the "NSP System") and a single electric control area (now referred to as a balancing authority) certified by the North American Electric Reliability Corporation ("NERC"). Within its regional footprint, MISO is responsible for providing transmission services, acting as NERC regional reliability coordinator, and operating a regional energy market. The NSP Companies joined MISO in 1999 as a condition of federal approval of the merger of the former Northern States Power Company (Minnesota) ("NSP") with New Century Energies, Inc. ("NCE"), and transferred functional control of their transmission systems to MISO in February 2002, when MISO began operations.

Our relationship with MISO is that of a transmission-owning member of MISO under the MISO Transmission Owners Agreement, a rate schedule on file with FERC. We participate in the Vertically Integrated Transmission Owners ("VITO") organization, working with MISO and other market participants as MISO develops policies and operational standards. We are also an active advocate within MISO and various stakeholder groups for

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3 The full name of the Transmission Owner's 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.
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 110,000 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 in a “day-ahead” market and then settle any deviations from their day-ahead commitments in a “real-time” balancing market. The Company both incurs costs and receives revenues associated with both markets. The MISO market also uses Financial Transmission Rights (“FTRs”) to hedge a participant’s exposure to congestion costs in the day-ahead market.

Since implementation of the MISO regional energy market in April 2005, the grid operation has evolved to an optimization of energy supply and transmission usage. Because MISO has direct generation 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.

Q. PLEASE DESCRIBE THE MISO ENERGY MARKET SERVICES.
A. The MISO uses software, hardware and human resources to operate this regional energy market. Schedule 17 of the MISO TEMT recovers the MISO market operation costs for this hardware, software and staff.

The MISO 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, confer a hedge against the costs of flexible dispatch is through use of FTRs. Another term used for the flexible generation redispatch cost is congestion cost. The FTRs are a tool that rebate congestion costs to parties with long-term transmission service rights 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.

Q. PLEASE DESCRIBE MISO BASIC SERVICES.

A. MISO performs ongoing basic services that began even prior to the regional energy market. Examples of this ongoing service include a) transmission service administration; and b) Reliability Coordination, a role established in compliance with the reliability standards of the NERC. Schedule 10 and its related components recover the basic costs for MISO offices, general administration and coordination of MISO transmission service planning and tariff administration. Schedule 10 also recovers costs incurred for compliance with federal and state regulatory activity. Without the underlying 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. The Company is thus billed all three administrative charges by MISO.

Q. The Company’s last electric general rate case was filed in 2005. Was NSP a member of MISO at that time?

A. Yes. In that rate case I presented testimony on the industry and regulatory developments that led to the creation of MISO. I also described the conditions involving our decision to join MISO.

Q. What MISO developments have occurred since the last Xcel Energy Electric general rate case?

A. There have been many developments with regards to MISO and its operations. The developments are discussed in detail in the Company’s Annual Automatic Adjustment of Charges (“AAA”) reports filed in 2006, 2007 and 2008. Some of the more important ones since 2005 include:

First, since our last electric general rate case, MISO facilitated the consolidation of utility contingency reserve sharing within the regional market footprint. At the time of our last rate case, the Company participated in the Mid-Continent Area Power Pool (“MAPP”) Generation Reserve Sharing Pool (“GRSP”), which required the NSP System to maintain approximately 372 MW of contingency reserves (both spinning and supplemental reserves). In 2007, the Company began to participate in the Midwest Contingency Reserve Sharing Group (“Midwest CRSG”) administered by MISO, initially through the MAPP GRSP and later directly. This has reduced the allocation of contingency reserves required for utility participants and created a more efficient regional generation dispatch. For
the NSP System, this change reduced our contingency reserve requirement
by 140 MW. I describe in my testimony how this has resulted in dispatch
cost savings for Xcel Energy customers. These savings would not be
achievable without the MISO entity being available to administer the
regional Midwest CRSG.

Also, the MISO has established minimum reliability compliance criteria to
facilitate capacity resource adequacy in the region under Module E of the
MISO Tariff. MISO will ensure utility compliance with mandatory reliability
capacity reserve standards established by the regional entities of the NERC.
This Module E development has replaced a role previously performed for
the Company by the MAPP GRSP, which required the NSP System to
maintain a capacity reserve of at least 15 percent. Module E reduces the NSP
System capacity reserve obligation, helping to reduce total generation
capacity costs to our ratepayers.

Third, MISO has established a new process for managing Financial
Transmission Rights ("FTRs"). The new method allocates Auction Revenue
Rights ("ARRs") to holders of long-term transmission service rights rather
than a direct allocation of FTRs. Then all parties seeking to acquire FTRs
participate in a regional auction. The intent of this development is to
provide a clear valuation on hedging rights and to improve access to
congestion cost rebates to market participants. MISO established four new
settlement charge types in the spring of 2008 that are associated with this
process improvement.
Finally, MISO is developing a regional Ancillary Services Market ("ASM"). This market is designed to increase efficiency of regional operations by reducing the amount of regional generation kept on standby condition and selecting reserve resources that are co-optimized with the existing energy markets. The ASM will also increase regional reliability by allowing MISO functional access to all standby resources, such as spinning and supplemental reserves. The ASM is expected to begin functioning in January 2009. Several additional MISO settlement charge types related to the ASM will begin at that time, some as costs to the Company and some as revenues. The Company, along with other Minnesota utilities, jointly filed with the Commission on May 9, 2008 in Docket No. E001,015,002,017/M-08-528 to address the proposed method for recovering these new ASM settlement charge types as well as the FTR/ARR charge types mentioned above. The joint petition is awaiting Commission action.

Q. HAVE THERE BEEN OTHER DEVELOPMENTS OF INTEREST?
A. Yes. Since the last rate case, the Company has increased the amount of wind generation resources it uses to supply its native load requirements. We have gained experience integrating variable output resources like wind generators into our portfolio of conventional generating resources. It has become apparent that good wind forecast accuracy is important to managing operational efficiency with high amounts of wind penetration. My testimony will also review our proposal to recover costs associated with improved forecasting performance for wind resources.
A. MISO Basic Services and Schedule 10 and 24 Costs

Q. PLEASE REVIEW MISO'S BASIC FUNCTIONS WHERE COST RECOVERY IS HANDLED THROUGH SCHEDULE 10 AND ITS RELATED COMPONENTS.

A. MISO's basic functions include functional control of the transmission grid, reliability coordination, transmission tariff administration, transmission planning, administration of resource adequacy and the regulatory support aspects related to these roles.

Functional control includes responsibility for regional transmission operations and managing transmission congestion. Through its ability to oversee the regional transmission grid on a much larger scale, and order individual control areas (balancing authorities) to respond to conditions on the grid, MISO provides a higher level of service reliability than was previously available.

Reliability coordination is a functional role defined under FERC-mandatory reliability standards established by the NERC. Under federal law and regulatory order, the NERC has been designated by FERC as the Electric Reliability Organization ("ERO") for the United States and NERC has adopted several standards for the performance of the reliability coordinator role. MISO's cost of providing reliability coordination, including the cost of complying with mandatory NERC standards, is recovered in Schedule 10.

MISO also administers a region-wide transmission tariff. This tariff provides grid access through a single point of contact. The MISO regional tariff replaced transmission services previously provided under individual utility
open access transmission tariffs ("OATTs") and MAPP Schedule F in 2002. Utilities in the region now provide and procure transmission services under the MISO Tariff. The MISO Tariff provides regional network transmission service as well as point-to-point service options. As a Transmission Provider, MISO is subject to both FERC requirements and NERC mandatory standards related to that function. MISO’s costs of providing regional tariff administration, including FERC and NERC compliance costs, are recovered in Schedule 10.

In addition, MISO facilitates regional transmission planning as part of its basic functions. This includes annual production of a forward 15-year comprehensive regional plan called the MISO Transmission Expansion Plan, or MTEP. As I understand it, the MTEP is developed in coordination with the biennial transmission plan submitted to the Commission by Minnesota’s transmission owning utilities, including the Company. In my opinion, MISO is currently the pre-eminent regional transmission planning organization in the United States, given the scope of their undertaking and their role as a catalyst for integrated grid planning in the Eastern Interconnection in North America. Transmission projects accepted through the MISO regional planning process in some cases are eligible to recover their costs across the regional footprint.

Fourth, MISO’s regional tariff now includes a Module E, which establishes the process for designating resources to use network transmission service. As part of this process, MISO oversees each Load-Serving Entity’s ("LSE") compliance with reliability standards established to ensure resource adequacy. As a provider of retail electric service, the Company is an LSE.
The Company now satisfies its resource adequacy requirement through Module E, which replaced the MAPP GRSP capacity reserve sharing pool.

MISO recovers the costs associated with these basic functions through an allocation in the MISO Tariff settlement schedules. The basic function administration costs include Schedule 10, Schedule 10-FERC and Schedule 24. The NSP System is billed these charges through the monthly MISO TEMT settlement process.

Q. PLEASE DESCRIBE MISO SCHEDULE 24.
A. In our previous electric general rate case we addressed Schedules 10 and 10- FERC. In this rate case Schedule 24 is new from MISO. Schedule 24 covers the costs associated with the Company’s local balancing authority operations in the MISO energy market. As a balancing authority operator, the Company receives reimbursement from MISO and as an LSE the Company incurs Schedule 24 charges. The Company proposes Schedule 24 recovery net of associated revenues and costs in base rates.

In the remainder of my testimony I refer to the total of these MISO basic costs as “Schedule 10 and its related components”, which includes Schedule 24. I also include in the definition of Schedule 10 and its related components the relatively small costs of administration of the Midwest CRSG and I include the relatively small annual expense for Midwest CRSG administration by MISO in my definition of these related components.

Q. IS THE COMPANY SEEKING RECOVERY OF PREVIOUSLY DEFERRED MISO ADMINISTRATIVE COSTS IN THIS PROCEEDING?
A. Yes. In the last electric general rate case the Company was authorized to defer 50% of MISO Schedule 16 and Schedule 17 charges, pending additional demonstration of MISO benefits. In my testimony I show the range of MISO regional energy market benefits sufficient to justify recovery of these deferred costs. Ms. Anne Heuer's testimony provides the amount of the associated revenue adjustment and the appropriate amortization period for recovering the deferred cost.

B. MISO Energy Market and Schedule 16 and 17 Costs

Q. Please review MISO's regional energy market operations functions, and MISO's cost recovery through Schedules 16 and 17.

A. The regional market functions include a Day-Ahead Market, FTRs and related administration, and a Real-Time Market as well as the associated financial settlements for these functions. In addition, MISO is planning to deploy an ASM in January 2009, which will be co-optimized with the Day Ahead and Real Time energy markets. MISO recovers the underlying costs for these regional services through MISO Tariff Schedules 16 and 17, and the NSP System is billed through the MISO settlement process. In this electric general rate case the Company is proposing recovery in base rates for MISO Tariff Schedules 16 and 17.
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 has decided several cases. These decisions responded to the continuing development of MISO and its functions. The NSP Companies agreed to join MISO in September 1999. Recognizing that the transition to MISO operations was at an early stage, the Commission’s June 12, 2000 Order in Docket No. E002/PA-99-1031 (the NSP/NCE merger) approved a settlement agreement between Xcel Energy and the Department of Commerce ("Department" or "DOC") that required the Company to provide additional information regarding the transition to MISO operations, as a precondition of receiving cost recovery of MISO costs.

Two years later, the Commission considered and approved our application to transfer functional control of our high voltage (100 kV and above) transmission system to MISO in Docket No. E002/M-00-257. In the Transfer Order, the Commission approved a Settlement Agreement reached between the Minnesota investor-owned utilities, the Department and the Office of the Attorney General ("OAG"). By that time, MISO had recently commenced basic operations. In its Transfer Order approving the application and settlement, the Commission expressed concerns regarding

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4 In the Matter of the Petition for Approval to Transfer Functional Control of Certain Transmission Facilities to the Midwest ISO, ORDER AUTHORIZING TRANSFER WITH CONDITIONS, Docket No. E002/M-00-257 (May 9, 2002) ("Transfer Order").
the potential benefits and costs to Minnesota electric ratepayers of MISO membership. At the time the Company filed the transfer petition, MISO and its members were planning only for basic operations; FERC had not yet ordered MISO to implement the regional energy market, as FERC's RTO policies had not yet evolved. The Commission required the Company to seek recovery of the basic operations costs (primarily MISO Schedule 10 costs) through a separate rate filing, such as a general rate case proceeding; and required various informational filings including annual reports in the Company's Annual Automatic Adjustment of Charges ("AAA") report submitted each September 1st.

Subsequent FERC policy required Regional Transmission Organizations ("RTOs") such as MISO to develop and deploy effective congestion management mechanisms. This is provided by regional energy markets using economic dispatch. Stakeholders within MISO recommended the design of the regional market, which was then developed, reviewed and approved by FERC, and began operations in April 2005.

In late 2004 to early 2005 the Company, along with other Minnesota electric utilities, filed with the Commission for an order regarding the recovery of certain MISO regional market settlement costs and revenues in the Fuel Cost Adjustment ("FCA"). The Company also requested recovery of additional MISO administrative costs associated with the operation of the regional market (i.e. Schedule 16 and 17), above the basic MISO administrative costs recovered in Schedule 10 and its related components. In that proceeding, Docket No. E002/M-04-1970, the Commission determined that the
administrative costs should be recovered in base rates, but the regional market settlement charge types could be recovered through the FCA.

In the fall of 2005 the Company filed a general rate case, Docket No. E002/GR-05-1428. In that case, the Commission allowed full base rate recovery of MISO's forecasted administrative costs as incurred through MISO Schedule 10 and its related components. Because the regional energy market had been in operation only a short time at that point in time, the Commission accepted the Department's recommendation to allow recovery of 50 percent of the Schedule 16 and 17 costs, with deferral of the remaining 50 percent until further analysis of the costs and benefits of the regional market could be made in this rate case. I will address these costs and benefits in the next section of my testimony.

In the spring of 2008, a few new regional market settlement charge types were established under the MISO Tariff related to FTRs. In response to these and in anticipation of additional new charge types related to deployment by MISO of its ASM, the Company and other Minnesota utilities filed a joint petition in Docket No. E001,015,002,017/M-08-528. The petition sought recovery of the existing new FTR-related and future ASM-related charge types and revenues in the FCA. The Commission has not yet issued an order in that proceeding. In that petition, the Company requested deferred accounting for the increased administrative charges recovered through MISO Schedules 17 and 24, with those costs considered for base rate recovery in a future general rate proceeding. The Company will no longer need deferred accounting for these costs, since they have been included in this proceeding.
Q. Did the Commission establish any conditions on continued participation in MISO?

A. Yes. In Docket No. E002/M-04-1970, the Commission established restrictions on utilities engaging in virtual energy transactions. The Company does not normally engage in virtual energy transactions, and consequently those restrictions have not come into play.\(^5\) In addition, the Commission required each utility to adopt the following accounting practices:

- Recording each transaction to separate sub-accounts 447 and 555.
- Recording to account 555 on an aggregated basis any revenues and cost linked to Day 2 locational marginal price ("LMP"), including generation offers to the market and load purchases used to serve native load customers, marginal loss compensations, and marginal loss credits, if allowed through the FCA.
- Using net accounting for purchases and sales for owned generation facilities.
- Continuing to use accounts 151 and 501 to record the fuel costs related to generation plants serving native load, the same way they were accounted for prior to the order.
- Continuing to use account 447 to reflect the true costs of off-system wholesale sales, including related MISO costs.
- Tracking in a separate sub-account each MISO charge and revenue.

\(^5\) An exception to this was in the early days of the MISO energy market, when a temporary MISO modeling problem created a need for the Company to use a virtual transaction to account for a native load resource in the Minnesota Power control area. The modeling problem was resolved in 2005 and the Company is no longer required to use this technique for its native load.
I am not personally involved with the accounting entries for MISO Day 2 settlement charges. However, as I prepared my testimony I conferred with the energy accounting function for the Company and confirmed that Xcel Energy is complying with these accounting requirements.

The Commission also requires that each utility use its lowest cost generation or resources to serve its ratepayers. Xcel Energy is complying with that requirement. As outlined in our last general rate case, the Company uses proprietary methods to ensure the least-cost resources are offered to the MISO energy market in a manner that preserves least-cost supply for native load.

The Commission also requires that each utility challenge any FERC action that would require any of the utilities to purchase energy to serve native load at LMP market clearing prices without associated offsets, action that would prevent utilities from netting payments/credits for owned generation or contracted purchases against the LMP payments made by retail load, or any other action preventing any utility from using its lowest cost generation or resource to serve its native load payments. The FERC has taken no such actions.
IV. COSTS/BENEFITS OF MISO PARTICIPATION

Q. HOW HAVE YOU APPROACHED YOUR ANALYSIS OF THE COST AND BENEFITS OF MISO PARTICIPATION?
A. I separately evaluated the impacts of MISO basic functions and MISO regional energy market operations on the NSP Companies' integrated system. In both cases, I worked to identify the areas of benefits and costs, and to quantify them if possible. In my testimony and exhibits, I attempt to calculate costs and benefits for the 2009 test year.

Q. ARE THERE ANY QUALIFICATIONS YOU WISH TO MAKE REGARDING YOUR ANALYSIS?
A. Yes. I have attempted to assess the costs and benefits in a manner that reasonably identifies potential savings and avoided costs. I analyzed benefits and costs using 2009 forecast data where available. I also analyzed benefits and avoided costs of the regional market. In my analysis, I highlight and present information to provide useful context, helping to identify trends or likely outcomes based on the empirical information. Finally, I present my observations as an active participant in both the prior and current electricity markets, providing additional context for the Commission to consider when evaluating the costs and benefits of the Company's participation in MISO.

Q. YOU MENTIONED THAT THE NSP COMPANIES OPERATE AN INTEGRATED SYSTEM AND ARE BOTH MISO MEMBERS. HOW ARE MISO COSTS CHARGED TO AND PAID BY THE NSP COMPANIES?
A. All MISO settlement charges and revenues are billed to the Company, which is responsible for managing both the transmission system equipment and
wholesale energy purchase and sales functions for the integrated NSP System. A portion of the system costs and revenues (approximately 15 percent net) is then charged to NSPW through our Interchange Agreement discussed by Ms. Heuer. For my analysis, I generally provide costs and benefits for the combined NSP System, as the costs and savings are shared among the NSP Companies' and their respective jurisdictions (Minnesota, North Dakota, and South Dakota; and Wisconsin and Michigan). Where I present the information at the NSP System level, the conclusions drawn from this information would hold true for each jurisdiction, including Minnesota, as the costs and benefits would be shared in the same proportions through the Interchange Agreement and jurisdictional allocation process.

A. The Benefits of MISO’s Basic Functions

Q. CAN YOU PLEASE SUMMARIZE THE BENEFITS OF THE BASIC MISO FUNCTIONS?

A. Yes. For this discussion, I consider the basic functions to include Reliability Coordination, transmission tariff administration, administration of a consolidated contingency reserve sharing group, regional planning and administration of regional resource adequacy. The NSP Companies participation in MISO basic functions during the 2009 test year results in:

- License Plate Rate benefits of approximately $6 million through avoided point-to-point transmission service purchases, both long-term firm and spot products;
- Avoided MAPP payments of approximately $0.3 million;
- Retail customer energy cost savings of approximately $50 million due to more efficient allocation of regional standby generation through the Midwest CRSG regional contingency reserve consolidation initiative;
- Improved transmission services; and
- Improved allocation of local Balancing Area costs to third party utilities with Schedule 24 revenues of approximately $1.8 million.

Q. CAN YOU SUMMARIZE THE COSTS?
A. Yes. For the 2009 budget, the NSP Companies' participation in MISO basic functions has costs for the Minnesota jurisdiction of:
- Schedule 10 costs of approximately $6.3 million;
- Regulatory assessments from FERC of approximately $2.5 million;
- Contingency Reserve Sharing Group administrative fees of $55,000; and
- Schedule 24 expenses of approximately $1.2 million.

Q. PLEASE SUMMARIZE THE CONCLUSIONS OF YOUR COST/BENEFIT ANALYSIS.
A. Considering both the benefits and the costs, I conclude that MISO basic functions benefited the Company's customers. Later I also describe additional benefits from the regional energy market made possible because of the basic functions. As such, the Commission should continue to allow recovery of the Minnesota jurisdictional share of MISO Schedule 10 and related component costs in the base rates established in this proceeding.

Q. PLEASE DISCUSS EACH OF THE BENEFITS, COSTS AND HOW YOU QUANTIFIED THE BENEFITS OF MISO BASIC SERVICES TO PROVIDE A BETTER UNDERSTANDING OF YOUR ANALYSIS.
A. As a result of MISO's regional tariff, the Company achieved savings on the cost of transmission services to deliver and serve our native load customers, compared with the pre-regional alternative tariff structures. This benefit stems primarily from the broad region covered by the MISO tariff using license-plate rates compared with the alternative of point-to-point transmission service under MAPP Schedule F or individual transmission provider OATTs, which resulted in sometimes paying several transmission providers to deliver an off-system resource (referred to as pan-caked rates). I estimate that transmission service for native load cost at least approximately $6 million less during the forecasted 2009 budget as a result of this change. Depending on the assumptions used in evaluating our cost of purchasing point to point transmission service if we were not a MISO participant, the avoided purchased service cost could run as high as $37 million in 2009. This estimate of savings is calculated based on actual network resource purchases in effect through the forecasted year, evaluating the costs under the non-MISO alternatives available for the applicable resource, such as individual utility OATT service or MISO point to point export service if the Company was importing a network resource from an area otherwise included within the MISO footprint. Exhibit (SJB-1), Schedule 2 summarizes the savings achieved on these transmission services to serve native load attributable to obtaining transmission service under the MISO Tariff.

Another increased transmission cost the Company would experience if it were not a MISO participant is captured by modeling the impact of the MISO "Regional Through-and-out Rate" or "RTOR". This rate surcharge would have applied to spot energy purchase transactions from MISO.
members if the NSP System were not a MISO participant. Although FERC ordered elimination of the RTOR between MISO and the PJM Interconnection RTO, there is still a RTOR in effect for transactions between MISO and entities outside MISO and PJM, including the historic MAPP footprint. Because these costs would be applied to the energy purchases delivered over the transmission system, I included those avoided costs in the evaluation of energy purchase benefits later in my analysis.

Q. PLEASE DESCRIBE THE SAVINGS RELATED TO AVOIDED MAPP PAYMENTS.
A. The establishment in the MISO Tariff of Module E terms for resource adequacy enabled our withdrawal from the MAPP GRSP capacity reserve sharing function on June 1, 2008. The NSP Companies incurred a net GRSP withdrawal fee of approximately $680,000 in 2008. We are not seeking to recover this withdrawal fee in the rate case. Due to the withdrawal, the NSP Companies saved enough in avoided capacity purchases for the summer of 2008 to offset this expense. The avoided MAPP GRSP fees for the 2009 budget forecast is $264,000 for the NSP Companies. The filed 2009 budget was prepared while the NSP Companies were still participants in MAPP and originally included this amount, but Ms. Heuer has adjusted the 2009 budget to reflect these savings.

Q. WHAT BENEFITS DID MISO PROVIDE WITH REGARD TO CONTINGENCY RESERVES CONSOLIDATION?
A. Under NERC reliability standards, utilities like the Company must maintain certain contingency reserves in order to preserve reliability. Specifically, a utility must have certain generation operating but not providing electricity (spinning reserves) and other generation available for start-up within 10
minutes (supplemental reserves) to respond to an unplanned unit outage. (Contingency reserves are a reliability requirement separate from capacity reserves.) The NERC standards also allow utilities to participate in reserve sharing groups rather than maintain the required reserves on their individual systems.

Prior to the regional energy market, the utilities in the MISO region participated in three geographically distinct generation reserve sharing groups. They were: the MAPP GRSP, the Mid-American Interconnected Network ("MAIN") and the East Central Area Reliability Council ("ECAR"). But for the existence of the MISO, 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, the Midwest Contingency Reserve Sharing Group, began operation on January 1, 2007.

Similar to the concept of an insurance pool, the increased number of participants in the Midwest CRSG 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 reserve generation held in standby mode. For the NSP system, the contingency reserve obligation was reduced by 140 MW in January 2007. This translates directly to energy production cost savings by increasing the
resources available for energy dispatch, because that 140 MW no longer had
to be held in reserve (e.g. spinning but not producing energy).

The Company has performed an analysis of the impact of this reserve
consolidation on the budgeted energy production costs for our retail
customers for 2007 and 2008. For this analysis we assumed that absent
MISO's role in consolidation we would have maintained the level of standby
generation in these years that existed pre-consolidation. Then we compared
an annual production cost model of this scenario with the actual budgeted
production costs for these years using the consolidated reserve sharing
allocation. The analysis results in an estimate of the NSP System native load
production cost savings in 2007 of approximately $63 million and an
estimate for 2008 of approximately $50 million. Exhibit____(SJB-1) Schedule
3 provides an overview of the analysis and results. The Company expects
similar savings for 2009.

Q. PLEASE DESCRIBE THE IMPROVEMENT IN TRANSMISSION SERVICES THAT HAS
OCCURRED AS A RESULT OF THE COMPANY'S PARTICIPATION IN MISO?

A. 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, since one transmission provider granting a request
(e.g. the Company) would affect neighboring systems (e.g. Minnesota
Power). 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 individual transmission provider (such as the Company) 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 therefore was a first-come-first served method with limited options. Absent the flexible dispatch available from a regional transmission provider and energy market, this very conservative access policy was consistent with preserving service reliability. If an overload condition occurred after the fact, for example because of an unplanned transmission line outage due to a storm, the approved transmission services were then curtailed (interrupted) through application of the NERC Transmission Loading Relief ("TLR") procedures.

In contrast, the present MISO market-based network service method permits full access to the regional grid within reliability-based limits. Moreover, when an unplanned outage occurs, MISO adjusts the dispatch to preserve transactions rather than curtailing them using TLR. This regional economic dispatch provides flexibility in transmission services and increased and more reliable access to the grid. Further, it provides a method to allocate properly the costs of flexible generation dispatch to the incremental users of the system.

Q. DO MISO BASIC OPERATIONS ALSO RESULT IN COSTS FOR THE COMPANY?
A. Yes. As noted, in my testimony I refer to the aggregate of the costs described below as "Schedule 10 and related components" for MISO’s basic services.
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. The NSP System Schedule 10 forecast for 2009 is $6.3 million and the Minnesota jurisdictional share is $4.6 million.

FERC also requires all transmission providers, including MISO and the Company, to pay an annual assessment to FERC. The assessment is billed to transmission providers based on transmission services provided. FERC ruled the assessment must apply to all loads served under an ISO or RTO regional transmission tariff, such as the MISO Tariff. FERC also ruled that MISO could recover the FERC assessment fee as a separate charge (it is recovered through Schedule 10-FERC) under the MISO Tariff. The total annual FERC assessment cost for the NSP System has increased compared to the pre-Day 1 era as a result of these FERC rulings. However, the FERC assessment cost billed to the Company via MISO is partially offset by a reduction in the Company's direct FERC assessment costs. The forecasted Schedule 10-FERC charge for 2009 is budgeted at $2.5 million. The Minnesota jurisdictional share is $1.8 million.

As discussed, MISO is also the administrator of the Midwest CRSG. This role is independent of the market operations role provided by MISO. The NSP Companies budgeted expense for our 2009 participation in the Midwest CRSG is $55,000. The Minnesota jurisdictional share is $40,172. In my testimony I consider the expense for MISO's administration of the Midwest CRSG Agreement to be included in the MISO basic costs.
Lastly, there is MISO Schedule 24. As discussed previously, Schedule 24 is a new charge type from MISO since our last retail rate case. It is used to recover the costs of providing Balancing Area ("BA" – formerly termed control area) services. This cost is distinct from the FERC pro forma tariff costs recovered under Schedule 1 of the MISO Tariff for Scheduling and Dispatch Control. The settlement of MISO Schedule 24 includes revenues to the Company that MISO collects from tariff customers as well as expense for the Company loads taking service under the MISO Tariff. Since the NSP Companies have load in other utility balancing authority areas and since other LSEs have loads in the NSP System balancing authority area, the net of the revenues and costs is a credit of $600,000 and the Minnesota jurisdictional share is $438,000 as reflected in the testimony of Ms. Heuer.

Q. ARE THERE ANY OTHER MISO TARIFF CHANGES FOR THIS 2009 BUDGET YEAR?

A. Yes. With the advent of the MISO ASM, the region will consolidate its Balancing Authority ("BA") operations into a single MISO regional BA. This change will increase the regional dispatch efficiency due to a load diversity effect that assists in meeting NERC standards for balancing generation and load. The region will retain Local Balancing Areas ("LBAs") such as the current NSP System balancing authority footprint, to serve as a reliability backup and to retain some key local control functions.

As a result of this BA consolidation, some transmission tariff ancillary services previously provided by the NSP System and invoiced by the Company under its OATT will transition to service under the MISO TEMT.
In particular NSP will no longer invoice wholesale transmission tariff customers such as municipal utilities or cooperatives with load in its historic BA footprint for OATT Schedules 3 – Regulation, Schedule 5 Contingency Reserve Spinning and Schedule 6 – Contingency Reserve Supplemental. Instead, MISO will begin settlement for these services. The new regional method will recover these costs through the net of the ASM settlement charge types. The 2009 test year budget assumes elimination of the revenues previously collected under NSP OATT Schedules 3, 5 and 6. The budget assumption anticipates Commission action in the joint utility petition filed in Docket No. E001,015,002,017/M-08-528. In that petition, the Company has proposed to pass through all net revenues from the sales of ASM services through the FCA. Thus, while revenues from OATT Schedules 3, 5 and 6 have been eliminated, based on the Company’s proposal in Docket No. E001,015,002,017/M-08-528, ratepayers will continue to receive these benefits through the FCA.

Q. YOU STATE THE MISO TARIFF REDUCED TRANSMISSION SERVICE EXPENSES FOR THE COMPANY. HOW DOES THE MISO TEMT RATE DESIGN AFFECT TRANSMISSION SERVICE REVENUES COLLECTED BY THE COMPANY?

A. When MISO began operations, the Company initially experienced reduced third party transmission service tariff revenues due to the adoption of the MISO regional tariff. The Company could now contract for network transmission service under license plate rates to deliver power to our system. However, other MISO members could transmit power across our transmission system without paying the Company directly for this use. By 2004, our transmission service revenues had risen back to approximately pre-MISO levels due to a combination of increased transmission rates, increasing
regional transactions and increasing revenue distributions from MISO. Starting in 2006, as old “grandfathered” transmission contracts expired and the Company renegotiated its agreements to be consistent with new regional practices, transmission revenues increased. At this point in the regional evolution the Company has recovered from the initial drop in revenues associated with the transition to license plate rates.

Q. BASED ON YOUR ANALYSIS, WHAT DO YOU CONCLUDE REGARDING THE VALUE OF MISO BASIC SERVICES TO COMPANY RATEPAYERS?

A. My analysis indicates the directly quantifiable and avoided cost benefits of MISO’s basic services are significant and far exceed the cost of Schedule 10 and its related components. The Commission should allow recovery of MISO’s Schedule 10 and its related components in base rates. To summarize the costs and benefits for the NSP Companies, I have prepared the table below, with dollars in millions:

<table>
<thead>
<tr>
<th>2009 MISO Basic Services</th>
<th>Costs</th>
<th>Revenue or Avoided Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Schedule 10</td>
<td>$6.3 million</td>
<td></td>
</tr>
<tr>
<td>Schedule 10-FERC</td>
<td>$2.5 million</td>
<td></td>
</tr>
<tr>
<td>Midwest CRSG</td>
<td>$55,000</td>
<td>$50 million</td>
</tr>
<tr>
<td>Schedule 24</td>
<td>$1.2 million</td>
<td>$1.8 million</td>
</tr>
<tr>
<td>Point-To-Point Avoided</td>
<td></td>
<td>$6 million</td>
</tr>
<tr>
<td>MAPP Fees Avoided</td>
<td></td>
<td>$0.3 million</td>
</tr>
</tbody>
</table>

The net 2009 test year benefits of MISO Basic Services thus exceed the costs by $48 million.
B. Benefits of MISO's regional energy market

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

A. Ratepayers derive benefits from the following aspects of the MISO regional market design for the 2009 budget year:

- Reduced energy costs to ratepayers in a range between $24 million and $162 million from a broad and efficient centrally dispatched market;
- More efficient use of limited transmission resources;
- Avoided redispatch costs and improved reliability, due to MISO's ability to observe regional grid conditions and selectively redispatch generators in response to reliability concerns, approximately $23 million for 2009;
- More efficient integration of variable output renewable energy resources such as wind generators, avoiding an estimated $10.1 million of ratepayer costs for 2009;
- 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
- Rebate of a portion of congestion costs from Financial Transmission Rights ("FTR") hedges estimated at approximately $10 million in 2009.

Q. HAS THE MISO REGIONAL MARKET DELIVERED THESE BENEFITS?

A. Yes. Our experience shows direct benefits from participation in the MISO regional energy market. Based on our experience, I believe there are solid indicators that the MISO regional market delivers benefits. These benefits
and the savings for our customers should increase as MISO implements plans for its ASM design (scheduled for startup in early 2009).

1) Reduced Energy Costs

Q. Please explain each of the expected benefits. What is your assessment of MISO’s ability to deliver lower energy costs due to the centrally dispatched system?

A. To illustrate this benefit, let me provide an example that occurred during 2007. The Company was in the process of refurbishing the Allen S. King generating plant. During the period of this outage we experienced unplanned outages at several other base load generating stations on the NSP System. Without MISO’s regional reliability coordination and regional market dispatch, the NSP System would likely have experienced service disruptions (i.e. possible interruption of firm retail load) due to these extreme operating conditions. However, no significant disruptions occurred; instead MISO was able to deliver needed resources to regional loads during this very challenging set of operating conditions. There have been numerous other operating conditions ranging from an outage of the 500 kV line from Canada to ice storms to tornados to other plant outage patterns over the years the regional market has been in operation. The experience from these conditions demonstrates clearly the reliability benefits from MISO’s system-wide look and effective regional generation dispatch tools.
Q. CAN YOU ATTEMPT TO QUANTIFY THE SAVINGS ACHIEVED THROUGH ACCESS TO REGIONAL MARKET PURCHASES?

A. Yes. We performed an analysis of our MISO forecasted regional market activity for our test year of 2009. This analysis indicates approximately $162 million of system savings due to purchases via the MISO market versus sole reliance upon our native resource portfolio. Exhibit (SJB-1), Schedule 4 summarizes the comparison of our 2009 budgeted production costs versus a scenario where the Company did not have access to MISO purchases or sales of market-based energy. The analysis includes the impact of lost opportunity for sales in the savings number shown above. The analysis also showed there would be hours where absent a market there would be a possibility of energy not served (i.e. the Company could not meet all native load demand in that hour). For this analysis we make the conservative estimate that the “value” of such unserved energy is $150/MWh. I would note that to make these scenarios comparable, neither the forecasted 2009 production budget number, nor the alternative scenario, includes allocation of estimated MISO administrative costs to native load, including Schedule 10, 10-F, Schedule 24, Schedule 16 and Schedule 17 costs.

Finally, if the NSP Companies were not in the MISO energy market, the company would still need to make significant energy purchases from market participants in MISO, as the available resources outside of the MISO footprint that the Company could expect to access would fall far short of our resource needs. In this scenario the NSP System would be subject to a market export surcharge, the “Regional Through and Out Rate” (“RTOR”) under the MISO Tariff. The RTOR is currently $7.56/MWh during on-peak and $3.59/MWh during off-peak. Using a mid-range rate of $5.5/MWh, the
NSP System will avoid over $24 million in RTOR fees as a result of MISO participation. If all else were equal, this amount establishes an approximate floor of the MISO market benefits for the NSP System.

We cannot predict the production budget with 100 percent certainty, nor is the scenario where we would rely solely upon the NSP System portfolio of generating resources entirely likely. However, my Schedule 4 shows that the purchases from the MISO regional energy market make energy available to us at a lower price than the cost of dispatching our own resources. The regional transaction benefit compared with use of native portfolio establishes an expected dispatch savings total of approximately $162 million for the year. Further, I use the RTOR from MISO applied to a stand-alone import volume to establish an approximate floor savings estimate for the coordinated dispatch savings due to MISO. There is no exact science in determining these “what-ifs” but by establishing these bookend estimates this comparison demonstrates that savings to Company ratepayers due to energy purchases from the MISO regional market is substantial.

2) More efficient use of limited transmission resources

Q. Please discuss the second category of benefit from the MISO regional market, the more efficient use of limited transmission resources.

A. This benefit is due to MISO having dispatch control over such a large footprint, allowing grid access that would not have been possible under the more conservative access policies and lack of redispatch control that existed pre-market. MISO evaluates the grid’s ability to accommodate the dispatch
of all network resources, which opens access to potential resources that were not considered “deliverable” prior to the market because of the conservative operational assumptions I discussed previously. The Company has made, and continues to make, substantial investments in transmission to provide delivery capacity for wind generation. If the Company were in a non-MISO region, however, I believe it would already have had to invest in or construct substantial additional new transmission facilities due to the less efficient utilization of transmission resources found in non-market areas. The old “rules” prevented the most efficient use of transmission and would have resulted in our customers incurring upgrade and expansion costs sooner. While many new transmission projects will be needed as generation resources are sited and as load grows, this deferred investment is a benefit to our customers, although it is difficult to quantify.

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 non-market, inefficient, “share-the-pain” TLR process. My Exhibit___(SJB-1), Schedule 5 compares the process for transmission transaction curtailments under TLR with those under the MISO regional energy market approach. Under the non-market TLR process, the transmission provider might need to order curtailment (and thus redispacth) 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, as I will describe shortly. Further, TLR curtailment directives 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.

To estimate the economic benefits of redispatch, in my Exhibit (SJB-1), Schedule 5, I provided with a hypothetical case where redispatch is more than 8 times more "efficient" than TLR on a MW basis and 3.4 times more efficient financially. By using an estimate of the efficiency difference and considering actual congestion costs incurred, I can estimate a dollar benefit associated with the more efficient redispatch methods used by the regional market. Even assuming that redispatch is only 2 times more financially efficient than TLR (a conservative estimate), the benefits of redispatch are substantial; the NSP System actual historical redispatch costs from 2007 and 2008 were $28,191,000 and $9,889,000 (through August), respectively. Assuming approximately $38,080,000 more for congestion management costs under the old pre-MISO methods over this 20-month period and my conservative estimate for gains from efficient MISO redispatch, this implies an estimated average annual benefit of $23 million.
4) **More efficient integration of variable output renewable energy resources such as wind generators**

Q. **How does the MISO regional energy market provide benefits for integration of variable output renewable energy resources such as wind generators?**

A. Prior to the MISO regional market a utility balancing authority area 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. Prior to the advent of significant wind generation, the largest variable (other than an unplanned unit outage) was changes in load, since most generation is controllable. When a variable renewable generation resource is located within a balancing authority, however, the BA needed to simultaneously respond to both variations in load and variations in the output of the variable generation. As the level of variable generation within a BA increases, the complexity of managing the variations increases.

The balancing of generation to load remains a requirement of utility balancing areas within MISO today, but with a major change made possible due to the regional energy market. The 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. The short term balancing component, termed “regulation,” is a reliability obligation that remains with each balancing area. But the regional dispatch now manages the longer-term variability of the wind farms due to the five-minute dispatch recalibration. The benefit of this arrangement is that the regional market dispatch is based
on economic offers from participating generators, so there is no additional cost allocation requirement involved in the intermittent dispatch variability because it has been broadened over the entire MISO market region. The proposed MISO ASM will provide further benefits with regards to wind integration.

In 2004, the NSP Companies completed participation in a groundbreaking analysis 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 Companies determined that the cost of wind resource integration at this relative level of penetration as a stand-alone utility was approximately $4.60 per MWh of wind output.

Subsequent to the MISO regional energy market startup, the NSP 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. The analysis considered various levels of wind generator penetration in the region. All levels of wind penetration in this more recent analysis were higher than the NSP 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.

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In the regional integration study, the lower range of wind penetration analyzed was 3400 MW. The study established that the consolidation of dispatch within MISO resulted in wind integration costs of roughly $2.55 per MWh of wind output. At the high range, with about 5000 MW of wind generation installed, the wind integration costs were projected at roughly $4.41 per MWh of wind output.

For most of 2008, the NSP Companies’ system operated with approximately 1150 MW of wind generation capacity owned or output purchased under purchased power agreements (“PPAs”). The Company-procured wind resources produced approximately 2,115,000 MWh in 2007 and in 2008 approximately 2,052,000 MWh through September. Using this 1150 MW installed resource level as a representative level of resource penetration in the dispatch stack, I estimate the difference in costs between the pre-MISO market method of wind integration and regional integration method and costs for the MISO market.

The pre-market study at this level of penetration indicated a cost of approximately $4.60/MWh of wind. The regional market study at this level indicated a cost of approximately $2.55/MWh of wind. The difference multiplied by the 2007 and 2008 (through September) actual total wind energy production of 4,167,000 MWh for the NSP System indicates roughly $10,626,000 in savings through more efficient regional operations over the 21 month period.
For the year 2009 we anticipate operating with approximately 1324 MW of installed wind generation capacity. For our budgeted 2009 wind production volume of 3,985,300 MWh, this results in 2009 avoided costs for our native load of approximately $10,162,500. This demonstrates a substantial benefit from the MISO regional dispatch and load-following capability.

The analysis above is conservative in that it does not identify an additional potential cost if the NSP Companies were not a MISO participant. Namely as a stand-alone balancing authority not able to access regional redispatch and balancing from MISO, we estimate that there would be numerous hours in 2009 where wind output would need to be curtailed in order to maintain system balance, thereby causing the Company to incur curtailment payments to wind generators under the PPAs. The costs of the stand-alone wind curtailment payments as wind penetration increases are not included in the estimated savings number shown above.

5) **Long-term Regional Grid and Generator Planning Benefits**

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

A. Drivers such as demand growth and specific generator additions remain the fundamental elements of the Company's resource and transmission planning efforts. But MISO's regional market permits additional information to be incorporated into the 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, which are flows on one provider's system due to grid interaction with external generators and loads. 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 has established inter-regional pricing methods with neighboring market regions. MISO is also involved in ongoing negotiations with external non-market utilities to establish equitable loop-flow coordination and cost allocation procedures.

Q. HAVE YOU ATTEMPTED TO ANALYZE LONGER-TERM BENEFITS THAT YOU ANTICIPATE WILL BE CREATED BY THE REGIONAL MARKET?

A. Only in a general sense. The Company, in cooperation with other regional utilities, is jointly proposing transmission system upgrades as part of the CapX 2020 project, as discussed by Mr. Walter T. Grivna. These upgrades will help ensure reliable grid service for Minnesota. This is especially important given the increase in wind generation. Due to the lack of dispatchable control for wind generators, strong grid support is essential to preserve reliability. Because CapX 2020 projects support regional reliability, they are eligible for MISO regional cost allocation and recovery. This means that other utilities, outside of Minnesota, who experience the reliability-related benefits of these upgrades will also participate in paying the costs of the new infrastructure. (The converse is also true, in that the NSP System is allocated a portion of costs from some upgrades in other states as well.) Although the debate over the best method for equitable allocation of these costs can seem endless, I strongly believe that regional transmission planning
and associated equitable cost allocation is a vital benefit and a key long-term benefit established under the MISO Tariff.

6) Financial Transmission Rights (FTRs)

Q. You mentioned that MISO issued FTRs as part of its regional energy market implementation. Please discuss the purpose and benefits of FTRs.

A. The FTR is a financial instrument that provides a form of “insurance” against the cost of congestion in the MISO energy 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 a shift in dispatch costs. MISO administers a process that allocates FTRs to help protect a market participant’s historical rights to use the grid. This approach helps balance interests and keeps costs lower for all market participants.

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.

Beginning with 2008, MISO made 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. 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. 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 MISO-facilitated auctions. When this ARR method was established in the MISO Tariff, the change created four additional related TEMT market settlement charge types. In this rate case we propose to continue the treatment of the new charge types for FTRs similar to the prior method established in Docket No. E002/M-04-1970 and include the net of debits and credits in the FCA.

In the full year of 2007 the NSP System received approximately $30,962,000 in rebates from FTRs. In 2008, through August, the NSP System received approximately $5,705,000 in rebates. We anticipate similar levels of rebates in 2009 to those expected to be received in 2008, or approximately $10 million in the test year. These rebates are a benefit for our customers as they hedge, or offset, the congestion costs associated with delivery of energy to our loads. The Minnesota jurisdiction portion of the rebated revenues from FTRs is credited to native load in the FCA.

Q. **DO FTRs PROVIDE ANY OTHER BENEFITS?**

A. Yes. I believe FTRs provide significant financial protection for our customers if a catastrophic event disabled numerous transmission facilities. This is because 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 from full exposure to congestion costs during abnormal grid operations.

For example on June 24-25, 1998, 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. NSP had to rely on local generation to help manage reliability on the congested grid and the increased costs of using local peaking resources were passed through to customers in the FCA. If a similar event happened today, the congestion cost of the transmission outage would be shared over a broad region rather than borne mostly by our customers, through a shared funding shortfall in FTR payments to all market participants. The value of this congestion cost “insurance” is difficult to quantify in advance but could be substantial.

In addition, 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. The Company credits the FCA with this rebate, pursuant to Commission decision in Docket No. E002/M-04-1970.

C. Cost of MISO Regional Market Operations

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 in base rates, please describe the purpose of MISO Schedule 16 and Schedule 17.

A. MISO Schedule 16 is used to recover the costs of administration of FTRs and associated ARR’s pursuant to the MISO TEMT. Schedule 16 is levied as a charge against the sum of the MW portfolio of FTRs held by market participants times the rate of 0.0120 per FTR-MW. 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 * $0.0120 per MWh = $105.12.

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 0.0840 per MWh. So, for example, if a market participant had 1 MW of generation that served 1 MW of load in all hours of the year, the charge would be (1 MW + 1 MW) * 8760 Hours * $0.0840 per MWh = $1,471.68.

From time to time MISO adjusts the rates for Schedule 16 and 17 to recover changes to their regional market operations costs. With the advent of the ASM and slightly increased expense associated with those systems, MISO increased its Schedule 17 rate on October 1, 2008. The rate changed to $0.0840/MWh from the prior month rate of $0.0704/MWh.

Q. What are the 2009 forecasted expenses for Schedules 16 and 17 for the company?
A. The 2009 NSP System MISO administrative costs for market operation and FTR administration (Schedules 16 and 17) is $8.1 million. The Minnesota jurisdiction portion is $5.9 million. The budget estimate for Schedule 17 assumes operation of the MISO ASM in 2009. The current schedule contemplates ASM startup as scheduled on January 6, 2009.

D. Cost-Benefit Comparison

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

A. Based on our experience in the MISO regional market environment, I believe the benefits of market participation outweigh the costs for the Company and its native ratepayers. As a result the Commission should authorize ongoing recovery of MISO Schedule 16 and 17 administrative costs for the regional market in base rates and continue (and expand for the new FTR charge types and the pending ASM charge types) the practice of reflecting the costs and revenues from non-administrative charge types in the FCA. Further, I believe the net benefits from MISO regional market will grow as MISO develops into its anticipated ASM design. The benefits from ASM are not currently included in my cost-benefit analysis, as this market has not begun operation.

The following table summarizes the NSP Companies costs and benefits as outlined in my testimony:
<table>
<thead>
<tr>
<th>2009 MISO Regional Market ($ millions)</th>
<th>Costs</th>
<th>Benefits or Avoided Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reduced Energy Costs</td>
<td></td>
<td>$24 to 162 million</td>
</tr>
<tr>
<td>More Efficient Transmission</td>
<td></td>
<td>---</td>
</tr>
<tr>
<td>Redispatch Avoided Costs</td>
<td></td>
<td>$23 million</td>
</tr>
<tr>
<td>Wind Integration avoided cost</td>
<td></td>
<td>$10 million</td>
</tr>
<tr>
<td>Long-term Planning benefit</td>
<td></td>
<td>---</td>
</tr>
<tr>
<td>FTR Rebates</td>
<td></td>
<td>$10 million</td>
</tr>
<tr>
<td>Schedule 16</td>
<td></td>
<td>$0.7 million</td>
</tr>
<tr>
<td>Schedule 17</td>
<td></td>
<td>$7.4 million</td>
</tr>
</tbody>
</table>

Q. **Does this analysis justify the company proposal to recover amounts related to deferral of Schedule 16 and Schedule 17 costs from the prior electric retail rate case?**

A. Yes. While the initial startup months of the MISO energy market involved some learning curve issues for MISO and the market participants, the benefits from MISO operations are now substantial. The benefits of the MISO regional market exceed the costs and the Commission should authorize recovery of the deferred amounts in retail rates, as indicated in the revenue analysis prepared by Ms. Heuer.
Q. HOW DO YOU THINK THE COMMISSION SHOULD WEIGH THIS INFORMATION IN THIS RATE CASE PROCEEDING?

A. I believe that the Company has acted reasonably with respect to federal initiatives leading to the development of RTOs such as MISO and has actively worked to respond to those initiatives in a manner that provides reliable service to customers at reasonable cost. The MISO market has provided substantial benefits through more efficient use of transmission resources, improved reliability of grid operations, better integration of wind energy resources into the regional dispatch, consolidation of regional generation reserve-sharing and improved regional planning. The Company has been deferring its Schedule 16 and 17 charges since April 2005. Much of my analysis has focused on the costs and benefits in the 2009 test year. But the same types of benefits have existed since the regional market started in 2005. While the value of the regional market has increased over time as MISO and its Members have made necessary adjustments, without those startup efforts we would not be able to obtain the benefits I have identified for 2009. Therefore, I recommend that the Commission also allow the Company to recover its deferred Schedule 16 and 17 costs over the amortization period proposed by Ms. Heuer.

V. WIND FORECASTING IMPROVEMENTS

Q. HOW DO YOU SEE THE INCREASING PENETRATION OF WIND GENERATION IMPACTING THE FORECASTING AND WHAT SHOULD THE COMPANY DO ABOUT IT?

A. Wind generation volatility creates forecasting uncertainties that cause planning and dispatch operation uncertainty. This uncertainty leads to
increased costs because other supporting generating units are started or stopped less efficiently. In 2008 the NSP System experienced maximum hour-to-hour wind output change of +517 MW and −488 MW. We have been averaging a day-ahead forecast difference of 21% and a real-time difference of 18.1% related to wind volatility. That volatility causes large swings in generation output for other units.

Currently we have approximately 1300 MW of wind on the NSP System, which is a substantial increase in the last 18 months. The most recent resource plan established an expectation to increase that amount to 3,969 MW by the year 2020. Clearly the impacts of wind forecast differences needs to be addressed to effectively plan and dispatch the system. To do so, Xcel Energy began a project to improve our wind generation forecasting.

Because of the volatility and increased growth of wind generation, we expect the cost risk due to inaccurate forecasting at our wind following plants to increase. Improving forecasting tools helps the Company control costs and avoids unnecessary wear and tear on generators. Avoiding unneeded startups and improving overall dispatch efficiency will help avoid costs for our customers. This avoided cost forms the basis for justification of recovery of our costs associated with the forecasting project.

Q. WHAT IS THE SCOPE OF THE FORECASTING PROJECT?
A. The project is an effort to improve our wind forecast and our ability to predict wind generation. The project is being undertaken through an arrangement with the National Center for Atmospheric Research (“NCAR”). We will add telecommunications equipment and weather monitoring
equipment at wind farm sites in order to provide site-specific weather data to NCAR. In return we will receive improved wind forecasting. The project also includes Wind Predictor software.

Q. CAN YOU DESCRIBE THE EXPECTED BENEFITS OF THE PROJECT?
A. By reducing the NSP System's forecast uncertainty we expect to reduce the difference between the amounts of wind generation scheduled in the financially binding day-ahead market in MISO and the actual real-time output. The benefits that will result from this improved prediction ability in the day-ahead market, which generally lowers our purchased power cost, and the benefits of this reduced expense are passed to customers through the FCA.

There is an additional benefit to the day-ahead accuracy improvement since FTR funding is based on the day-ahead market. With the increased accuracy, the FTR rebate will more be a better offset to the realized congestion cost. The FTR rebates are also credited to native load in the FCA.

Q. WHEN WILL THE PROJECT BE IMPLEMENTED?
A. The project will begin in the fall of 2008 and is expected to be complete prior to summer of 2009.

Q. WHAT IS THE COMPANY SEEKING IN THIS CASE REGARDING THIS INITIATIVE?
A. The Company is seeking recovery of the allocated jurisdictional share of the project costs in rates. As noted, the Minnesota jurisdictional share of this
project is $652,000. Ms. Heuer discusses the specifics of cost recovery in her testimony.

VI. WHOLESALE MARGINS

Q. PLEASE SUMMARIZE THE CURRENT REGULATORY TREATMENT OF WHOLESALE MARGINS.

A. Pursuant to a settlement in the Company’s last general rate case, the Company currently returns 100 percent of asset-based margins resulting from sales of unused NSP System resources (generation or purchases) to customers. The Company returns 25 percent of non asset-based margins (from wholesale trading operations) to customers, with the additional assurance that ratepayers bear no risk of negative non asset-based margins on an annual basis. Finally, the settlement provides for the return to ratepayers of 80 percent of asset-based margins resulting from sales of ancillary services. In the past, a limited amount of sales due to our spinning reserve requirements have qualified for this category. With the implementation of MISO’s ASM on the horizon, the Company has proposed in Docket No. E001,015,002,017/M-08-528 that 100 percent of margins related to ancillary services also be returned to customers. Thus, based on the Company’s proposal in that proceeding, our customers will now receive 100 percent of all asset-based margins as a credit to the FCA on a monthly basis.

Q. WHAT MECHANISM DO YOU RECOMMEND FOR TREATMENT OF WHOLESALE MARGINS IN THIS PROCEEDING?
A. I recommend continuation of the existing mechanisms: return of 100% of all asset-based margins to ratepayers and 75/25 percent shareholder/ratepayer sharing for non asset-based margins.

Q. WHY DO YOU RECOMMEND CONTINUATION OF THE EXISTING MECHANISM FOR ASSET-BASED MARGINS?

A. I believe the existing mechanism for asset-based margins has ensured that ratepayers receive the full benefit of wholesale sales originating from the Company’s portfolio of generating resources.

Q. PRIOR TO YOUR LAST RATE CASE, THE COMPANY PROVIDED A FIXED CREDIT TO RATES IN LIEU OF THE DOLLAR-FOR-DOLLAR FCA CREDIT THAT IS NOW IN PLACE. WOULD IT BE POSSIBLE TO APPLY A FIXED CREDIT IN THIS PROCEEDING RATHER THAN CONTINUE WITH THE EXISTING MECHANISM?

A. It would be possible, but I do not believe it would be advisable at this time. First, the current mechanism is a more accurate method of ensuring that ratepayers receive the full benefit of energy sales from unused generation into the wholesale market. Given today’s high cost of fuel and purchased power, I believe that the Company should ensure sales are used to offset some of these costs. A fixed credit to base rates simply cannot provide the same assurance. Since 2005, wholesale margins have averaged approximately $52 million per year (total NSP System). However, there has been wide variation in the actual margins, ranging from $31 million in 2007 to $74 million in 2005. This type of volatility makes it nearly impossible to ensure that ratepayers receive an appropriate level of the benefits if a fixed credit mechanism were used.
Second, a fixed credit mechanism could impact the accuracy of cost assignment methods for retail and wholesale allocations. If a fixed credit mechanism were adopted, additional work would be required to ensure accurate and transparent cost assignment policies. A detailed design of revisions to cost assignment methods would be necessary to ensure an equitable and accurate outcome. At this time I believe it would be counterproductive to switch back to a fixed credit mechanism. Any significant cost assignment changes will, by definition, alter the potential credit that would likely be applied to base rates. Therefore I believe that reestablishment of a fixed credit to rates is premature for this proceeding.

Finally, as discussed above, the Company is currently in the process of adding significant wind generation resources onto the system. Due to current and historical cost assignment methods, large swings in wind resource productions create significant fluctuations in the Company's asset-based sales. As day-ahead commitments are made on behalf of our native customers, increased real-time wind production exceeding expectations will drive real-time energy sales, since all day-ahead purchase commitments are directly assigned to native load. Given the Company's proposal to continue to return all asset-based margins to ratepayers through the fuel clause, these increasing swings in wind generation output will not cause ratepayers to bear increased purchased power costs at the expense of wholesale sales. Rather, wind power fluctuations will drive additional real-time sales, but these sales will offset any native cost impacts as the margins are returned to ratepayers through the existing mechanism. However, this further highlights the value in continuing to return all asset-based sales to ratepayers through the FCA rather than through a fixed credit to base rates. Asset-based margins will
exhibit increased fluctuation as the Company adds wind resources and a fixed credit based on these increasingly volatile margins would be ill-advised at this time.

In summary, I recommend continuation of our existing practice of returning 100 percent of actual asset-based margins to customers in the FCA. This ensures that ratepayers receive the benefits of the native generation assets and is a superior to a fixed credit mechanism until other cost assignment methods are developed. Lastly, the FCA credit addresses the significant uncertainty in wind energy production as additional wind resources are added to our system.

Q. The margin sharing settlement agreement in the Company's last rate case stated that a retail incentive mechanism may be appropriate to further the efficiency of the Company's fuel and energy purchasing practices. Is the Company proposing an incentive mechanism in this proceeding?

A. No. The Company continues to believe an incentive mechanism could be beneficial to both ratepayers and the Company, based on the experience of our Public Service Company of Colorado affiliate in Colorado. The Company has discussed incentive mechanism concepts with stakeholders in Minnesota in the ongoing informal discussions related to costs and revenues under the MISO Day 2 energy market. Those discussions could be included as part of the resolution of the issues related to the ratemaking treatment of the costs and revenues under the MISO ASM, if stakeholders are interested. However, the Company is not proposing a comprehensive retail incentive mechanism for fuel and energy purchasing practices in this proceeding.
VII. PURCHASED CAPACITY COSTS/PPA ISSUES

Q. Please discuss the Company's proposed purchased capacity cost budget for 2009.

A. The Company's purchased capacity cost budget includes all of the Company's short and long-term purchased capacity costs for the test year. These costs include all of the demand charges embedded in our long-term purchased power agreements as well as our expected short-term capacity purchases. For the test-year, purchased capacity costs are $152.5 million, an increase of approximately $16 million since our last case (Minnesota jurisdiction).

Q. Why have these costs increased?

A. The primary driver for this increase is the addition of a long-term purchase agreement with Invenergy Cannon Falls, LLC. Inclusion of the demand costs associated with this agreement increased capacity costs by approximately $15 million in the test-year (Minnesota jurisdiction). Trade Secret Exhibit (SJB-1), Schedule 6 summarizes the test year purchased capacity cost of the new agreement.

Q. The Commission order in Docket No. E002/M-04-451 approving the Company's PPA with the Mankato Energy Center stated that recovery of capacity costs would be addressed in the Company's next electric rate case, and ratepayer financial responsibility would be limited as described in article 11.2(b) of the PPA. Do you have any comments?
A. The Company's PPA with the Mankato Energy Center ("MEC"), a subsidiary of Calpine Corp., was considered in the Company's 2005 rate case (Docket No. E002/GR-05-1428). The Commission allowed the Company to include the Minnesota Jurisdiction allocation of the test year cost of the capacity payments to MEC in the final rates established in that proceeding. The MEC facility is now part of the Company's portfolio of generation resources needed to serve our retail customers in Minnesota, and there is no reason for the Commission to reconsider the findings in the prior rate case related to base rate recovery of capacity payments to MEC.

The Commission order notes that PPA includes a subordinated mortgage provision and security fund to allow the Company to manage the financial risks associated with the PPA. The Company is not aware that the section 11.2(B) provisions of the PPA would be triggered either in the remainder of 2008 or during the 2009 test year.

Q. THE COMMISSION ORDER IN DOCKET NO. E002/M-04-1426 APPROVING THE COMPANY'S PPA WITH INVENERGY CANNON FALLS, LLC NOTED POTENTIAL ISSUES REGARDING TO THE DELIVERABILITY OF THE PLANT OUTPUT, BASED ON THE MISO SYSTEM IMPACT STUDY RELATED TO INTERCONNECTION OF THE NEW PLANT. CAN YOU PROVIDE AN UPDATE?

A. Yes. I conferred with the Company personnel responsible for acquiring transmission service to deliver new generation resources (either purchased power or Company-owned facilities) to our load centers. In order to accredit the peak capacity levels for the Invenergy facility, the Company pursued firm Network Integrated Transmission Service ("NITS") under the MISO TEMT. MISO granted the Company's request in November 2006 for
a total of 357 MW, the winter capacity of the plant. Firm NITS is the highest, most reliable level of transmission service for generation to load deliveries. The firm NITS transmission service enables the Invenergy plant to be a Designated Network Resource ("DNR") for the NSP System under the MISO TEMT. The direct testimony of Mr. Grivna discusses the extensive transmission facility upgrades installed by the Company's transmission function to provide deliverability of the Invenergy facility. The Company has experienced no electric transmission deliverability issues related to the Invenergy plant since it was placed in service earlier in 2008.

Q. THE COMMISSION ORDER IN DOCKET NO. E002/M-95-174 APPROVING THE COMPANY'S PROPOSAL TO ALLOW PARTICIPATION OF COMPANY GENERATION IN THE COMPETITIVE BIDDING PROCESS REQUIRED THE COMPANY TO TRACK CAPACITY RELATED NON-PERFORMANCE PENALTIES ON COMPANY GENERATION FOR RETURN TO RATEPAYERS IN A FUTURE RATE CASE. DO YOU HAVE ANY COMMENTS?

A. That Commission order related to an initiative at the time to allow the Company to participate in the competitive bidding process for new generation resources identified in the Resource Plan process. Since the order, much has changed. The Company no longer has any non-regulated generation affiliates, and individual Company generation upgrade projects (such as the upgrades to the King, High Bridge and Riverside plants) have been considered by the Commission in dockets separate from the bidding process. Moreover, the Company did not incur any MAPP GRSP capacity reserve penalties as a result of non-performance by Company generation facilities since the Company's last rate case. Thus there were no non-performance penalties to track or return to ratepayers during this period. As
I discussed previously, MISO Module E is replacing the MAPP GRSP, and Module E does not use the penalty structure previously used by the MAPP GRSP. The Company does not anticipate any non-performance penalties in the 2009 test year.

Legislative and Commission policies, the Company's methods for acquiring or self-building incremental generation capacity, and wholesale capacity penalty structures have changed dramatically in the twelve years since the 1996 Commission order in Docket No. E002/M-95-174. The Commission recognized these changes in its November 17, 2005 order in the Company's 2004 Resource Plan (Docket No. E002/RP-04-1752). The Company thus respectfully requests that the compliance requirement from Docket No. E002/M-95-174 be terminated effective with the final order in this rate case.

VIII. SUMMARY AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATION FOR THIS PROCEEDING.

A. The Company has presented this analysis to support continued recovery of MISO basic and market administrative costs in base rates as well as continuation and expansion of the practice of passing MISO energy market charges and revenues through the FCA. While the MISO benefits have been offset to some extent by various costs, the overall benefits exceed costs, especially when various intangible or reliability-related benefits are considered. Therefore, the Commission should allow full recovery of MISO costs.
With respect to MISO administrative costs such approval would allow recovery of the Minnesota jurisdiction share of the $8.8 million in 2009 MISO Schedule 10 costs (and related components including $2.5 million for the FERC assessment) through the base rates established in this electric general rate case. The Minnesota jurisdictional share for the test year is $6.4 million. In addition I recommend the Commission allow recovery of Schedule 16 and Schedule 17 administrative costs in base rates. The Minnesota jurisdictional share of those costs for 2009 is budgeted at $5.9 million. I also recommend that the Commission authorize recovery of previously deferred portions of Schedule 16/17 costs in the base rates established in this rate case. The deferred costs to be recovered over the coming three-year period are $3.3 million per year. While the joint utility petition regarding treatment of MISO ASM costs requested a deferred treatment, we are including all test year Schedule 17 costs (including the increase related to ASM implementation) in base rates and no longer request that treatment.

Further the Commission should allow recovery of the Minnesota jurisdictional share of the Wind Forecasting Project costs and the capacity costs associated with the new PPA with Invenergy Cannon Falls, LLC. Finally, I recommend continuation of the existing margin sharing mechanisms for wholesale activity.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?
A. Yes, it does.
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 interface on wholesale market design issues and regulatory support for retail and wholesale rate cases; reliability standards development; policy leadership in the areas of energy trading and ancillary services; energy supply contract analysis; and activity in open access transmission tariff rights management for the business unit, including financial transmission rights. I provide operations leadership and support for wind integration issues.


Past Positions Include:
Senior Operations Consultant, Xcel Energy Markets (July, 1999 – August 2001)
Transmission Services Project Manager, 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: Board of Directors, Utility Wind Integration Group (UWIG); North American Electric Reliability Council (NERC) Standards Committee; WECC Seams Coordination Vice-Chair. Prior activities: Chairman, Midwest ISO Operating Reserves Task Force; Chairman, Midwest ISO Readiness Metrics Task Force; NERC Engineering Committee, MAPP Pool Committee, others.
Point-to-Point Transmission Services Required in a Scenario under which NSP is not part of MISO

Assumptions

- NSP would not need exporting Point-to-Point transmission service to supply NSP's native loads in other control areas (ALTW, DPC, GRE, MP, OTP, & WAUE).
  Section 31.3 of Xcel's OATT allows NSP's native loads external to NSP's transmission system to utilize Network Integrated Transmission Service.
  
- Deliveries listed below are either currently in effect, or expected to be in effect by 2009.

- MISO's Point-to-Point transmission service rate is: $2,620.75/MW-month; or $31,449.03/MW-year.

- NSP's Point-to-Point transmission service rate is: $2,909/MW-month; or $34,904/MW-year.

Avoided Point-to-Point Transmission Service

NSP presently is required to use Point-to-Point transmission service under MISO's OATT to supply NSP's native loads outside MISO's footprint (in DPC & WAUE). If NSP was a stand-alone Transmission Provider, NSP could instead use network service under Xcel's own OATT (Section 31.3 of Xcel's OATT).

<table>
<thead>
<tr>
<th>Avoided MISO PTP Service</th>
<th>Amount</th>
<th>Annual Avoided Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>PTP service from NSP's fleet of resources to the NSP-DPC interface.</td>
<td>136 MW</td>
<td>$4,277,068</td>
</tr>
<tr>
<td>PTP service from NSP's fleet of resources to the NSP-WAUE interface.</td>
<td>2 MW</td>
<td>$62,898</td>
</tr>
</tbody>
</table>

Total Annual Avoided Cost = $4,339,966

Certain Incremental Point-to-Point Transmission Service

NSP presently imports part of its power supply from resources outside its transmission system using MISO network service. If NSP was a stand-alone Transmission Provider, NSP would instead be required to use Point-to-Point transmission service under MISO's OATT to deliver these resources to NSP's transmission system.

<table>
<thead>
<tr>
<th>Incremental MISO PTP Service</th>
<th>Amount</th>
<th>Annual Avoided Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Purchase from Dynegy</td>
<td>108 MW</td>
<td>$3,396,495</td>
</tr>
<tr>
<td>Central Minnesota Ethanol Cooperative on MP's system</td>
<td>1 MW</td>
<td>$31,449</td>
</tr>
<tr>
<td>Cyprus Silver Bay on MP's system</td>
<td>40 MW</td>
<td>$1,257,961</td>
</tr>
<tr>
<td>Fibrominn on OTP's system</td>
<td>50 MW</td>
<td>$1,572,452</td>
</tr>
<tr>
<td>Laurentian Energy Authority (Hibbing) on MP's system</td>
<td>20 MW</td>
<td>$628,961</td>
</tr>
<tr>
<td>Laurentian Energy Authority (Virginia) on MP's system</td>
<td>15 MW</td>
<td>$471,735</td>
</tr>
<tr>
<td>Jeffers Wind project on ALTW's system</td>
<td>51 MW</td>
<td>$1,603,901</td>
</tr>
<tr>
<td>Metro Wind project on GRE's system</td>
<td>1 MW</td>
<td>$31,449</td>
</tr>
<tr>
<td>Agassiz Wind project on OTP's system</td>
<td>2 MW</td>
<td>$62,898</td>
</tr>
<tr>
<td>Velva Wind project on GRE's system</td>
<td>13 MW</td>
<td>$408,837</td>
</tr>
<tr>
<td>Ewington Energy wind project on ALTW's system</td>
<td>20 MW</td>
<td>$628,961</td>
</tr>
<tr>
<td>Averill Wind project on OTP's system</td>
<td>5 MW</td>
<td>$157,245</td>
</tr>
</tbody>
</table>

Total Certain Annual Incremental Cost = $10,252,384
Additional Potential Incremental Point-to-Point Transmission Service

NSP presently has some long-term delivery arrangements through MISO that could possibly have continued without cost under grandfathered treatment if NSP was a stand-alone Transmission Provider. However, there was the potential for additional costs to the extent these deliveries might have had to use Point-to-Point transmission service.

### Incremental MISO PTP Service

<table>
<thead>
<tr>
<th>Service Description</th>
<th>Amount</th>
<th>Annual Avoided Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>GRE Diversity Exchange (50 MW export on Xcel's OATT during winter)</td>
<td>50 MW</td>
<td>$872,700</td>
</tr>
<tr>
<td>MHEB Diversity Exchange (200 MW export on Xcel's OATT during winter)</td>
<td>200 MW</td>
<td>$3,490,800</td>
</tr>
<tr>
<td>MHEB Diversity Exchange (150 MW export on Xcel's OATT during winter)</td>
<td>150 MW</td>
<td>$2,618,100</td>
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<tr>
<td>Summer purchase from MPC's Coyote #1 using MISO's OATT</td>
<td>100 MW</td>
<td>$1,572,450</td>
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<tr>
<td>MHEB Adverse Water Path from NSP to the US-Canada boundary on Xcel's OATT</td>
<td>500 MW</td>
<td>$17,452,000</td>
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<tr>
<td>Stanton Displacement reciprocal delivery from NSP to GRE on Xcel's OATT</td>
<td>188 MW</td>
<td>$6,561,952</td>
</tr>
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</table>

Total Additional Potential Annual Incremental Cost = $32,568,002
Contingency Reserve Consolidation  
Avoided Cost  

<table>
<thead>
<tr>
<th></th>
<th>2007 Budget 9-08-06</th>
<th>2008 Budget 4-30-07</th>
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<tbody>
<tr>
<td>93 Spin/139 Supplemental</td>
<td>1,258,085</td>
<td>1,149,310</td>
</tr>
<tr>
<td>226 Spin/150 Supplemental</td>
<td>1,320,949</td>
<td>1,198,970</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
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<tr>
<td></td>
<td>62,864</td>
<td>49,660</td>
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Dollars shown in ($000s)  

This is the actual production cost budget based on the reduced reserve allocation due to MISO.  
This is the production cost budget calculated if we had not had the benefit of the reduced allocation.
### Dispatch Cost Savings
Due to Regional Market Purchases

<table>
<thead>
<tr>
<th>Dollars in ($000)</th>
<th>2009 Revised Budget 8-11-08</th>
<th>No Market (35.8GWhs of ENS)</th>
</tr>
</thead>
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<tr>
<td></td>
<td>1,324,196 GWhs $/MWh ($000s)</td>
<td>1,486,721 GWhs 35.8 $150 5,370</td>
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<td></td>
<td>162,525</td>
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The $162,000,000 represents increased production costs for native load if no regional market energy purchases are used to supplement the economic dispatch. For hours where native resources are insufficient, the analysis assumes a cost of emergency energy purchases at $150/MWH, likely a conservative value.
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%.
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

Decrement Unit -2

Source +100

Sink

Increment Unit +2

Station M

Station N

Assume 50% PTDF from Incremental Unit to Decremental Unit.
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.
### Purchaser:
Northern States Power

### Seller:

### Expected Start Date:
May 1, 2008

### Expected Termination Date:
April 30, 2028

### Contracted Capacity (Net Capability):
367,000 kW

(Two gas turbine generators)

### Fixed Charge Prices:

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<tr>
<td>Total</td>
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*Price change occurs on May 1st of each year and is valid through April 30th of the following year.

### Fixed Charges:

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<tbody>
<tr>
<td>Capacity Dispatchability Gas Interconnection Cost Adjustment</td>
<td>BEGIN TRADE SECRET</td>
<td>END TRADE SECRET</td>
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### Annual Fixed Charges:

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