Direct Testimony and Schedules
Thomas A. Imbler

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
d/b/a Xcel Energy
For Authority to Increase Rates for Electric Utility Service in Minnesota

Docket No. E002/GR-05-1428
Exhibit 19

Wholesale Margins

November 2, 2005
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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.
A. My name is Thomas A. Imbler. My business address is 30 Denver Place, 1099 18th Street, Denver, Colorado 80201.

Q. FOR WHOM ARE YOU TESTIFYING IN THIS PROCEEDING?
A. I am testifying on behalf of Northern States Power Company d/b/a Xcel Energy ("Xcel Energy" or "the Company").

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?
A. I am the Vice President of Commercial Operations for Xcel Energy Services Inc., the service company for Xcel Energy Inc. My resume is included as Exhibit__ (TAI-1), Schedule-1. I provide the present organization chart for my areas of responsibility in Exhibit__ (TAI-1), Schedule-2.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.
A. I have worked in the energy business for my entire career and in energy marketing and trading since 1992. Much of my career has been spent at Xcel Energy and one of its predecessors, New Century Energies, Inc.

In my current position, I am responsible for the economic dispatch of the Xcel Energy utility operating companies' owned and purchased resources to ensure that our customers receive low-cost, reliable energy. As such, my organization provides the interface for Xcel Energy's interactions with the Midwest Independent Transmission System Operator, Inc. ("MISO"), securing purchases required to meet our customers' needs both in MISO's
Day 2 Market and through bilateral arrangements and offering our generation for sale into that market. I am also responsible for the procurement of fuel for our fossil-based generation facilities. Finally, I am responsible for short-term wholesale sales activities, which now primarily occur within MISO's Day 2 Market.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?
A. I sponsor the Company's proposed treatment of wholesale margins in this general rate case proceeding for the Minnesota Public Utilities Commission ("MPUC" or "Commission") to consider. Because of changes in energy markets, I do not believe an appropriate level of test-year wholesale margins can be determined with complete certainty. To minimize risks to both the customers and the Company -- and to better align ratepayer and shareholder interests -- I propose to implement a margin-sharing plan through the Fuel Clause Adjustment ("FCA"). I discuss the reasons why wholesale margins should be recognized in the FCA (rather than base rates) and based on actual performance (rather than a forecasted credit).

Q. HOW HAVE YOU ORGANIZED YOUR TESTIMONY?
A. First, I provide a brief overview of various market changes that influence our procurement of resources to meet our customers' need. This information provides context for my proposals for treating wholesale margins in this general electric rate case. I then discuss the potential for a retail incentive mechanism and suggest an approach for pursuing the development of such a mechanism. Finally, in response to questions from the Commission, I provide additional detail regarding the Company's fuel and short-term power procurement. This information should be useful in understanding our
practices for meeting customer needs and creating additional benefits through wholesale activities.

II. MARKET OVERVIEW

Q. PLEASE DESCRIBE BRIEFLY THE CURRENT STATE OF THE WHOLESALE ENERGY MARKETS IN WHICH XCEL ENERGY OPERATES.

A. Until approximately a decade ago, wholesale electric energy markets in the Upper Midwest market consisted primarily of vertically integrated utilities making wholesale capacity or energy sales or purchases at "cost-based" rates regulated by the Federal Energy Regulatory Commission ("FERC"). Except for long-term bilateral transactions, such as the Company's diversity exchange and capacity purchase transactions with the Manitoba Hydro Electric Board ("Manitoba Hydro"), or capacity sales to utilities in eastern Wisconsin, most energy transactions were short-term "economy energy" transactions by regulated utilities under cost-based rates.

Today, as a result of the federal and FERC restructuring initiatives discussed in the Direct Testimony of Mr. Stephen J. Beuning, wholesale energy markets have evolved to be very complex, competitive and volatile. Some of the most prominent changes include:

- **Market Participants.** There are numerous entities now authorized to make wholesale sales at "market-based" rates, and "open access" transmission service is available to deliver the capacity and/or energy. Many of these participants do not serve any retail electric customers.

- **Generation Mix.** More electric generation is fueled by natural gas, and wholesale natural gas fuel prices have been both rising and volatile.
• Tightening Markets. Because of increasing electricity demand and limited generation supplies and transmission capacity, underlying prices for energy commodities -- both fuel and electricity -- are showing dramatic and unprecedented increases.

• New Tools. Many of the energy products and financial hedging tools now available to Xcel Energy were not available a decade ago. This increased complexity and volatility in the energy markets appears to be part of a permanent change, and will dictate how we develop resource strategies to obtain least-cost resources for our customers.

Finally, as perhaps the most significant change, FERC in 2003 ordered MISO to implement its Day 2 wholesale market. After extensive efforts by both MISO and market participants (including Xcel Energy) and several contested regulatory proceedings at FERC, the Day 2 market went “live” on April 1, 2005. Mr. Beuning discusses issues related to the effect of implementation of MISO Day 2 on the Company's costs and revenues in more detail. My testimony will discuss MISO Day 2 in the context of its impact on wholesale trading activities.

Q. How has the MISO Day 2 market affected the Company's trading operations?

A. It has greatly increased the complexity of meeting our customers’ power supply needs. As discussed by Mr. Beuning, as part of the overall Day 2 market design, MISO created a central power exchange for all day-ahead and real-time energy purchases and sales. My organization is responsible for the day-to-day interaction with the MISO market and the execution of our trading strategies.
Q. Can you discuss how your organization participates in the Day 2 market and secures needed resources for customers?
A. Yes. Exhibit _ (TAI-1) Schedule-3 provides information regarding Xcel Energy's participation in the Day 2 Market. In it, I provide summary information regarding the tools and approaches we employ in our daily interaction with MISO and our planning to meet seasonal customer needs. I provide this information in response to Commissioners' questions regarding our participation in the Day 2 Market and its impact on customers' costs. I intend for this information to complement the Direct Testimony of both Mr. Beuning and Mr. Camille A. Abboud, who discusses the drivers behind recent increases in fuel and purchased power costs.

Q. What else does this Schedule show?
A. It provides information regarding our acquisition of fuel for our generating plants, which is performed by my organization. Securing competitively priced fuel is important to obtaining low costs for our customers.

III. WHOLESALE MARGINS

Q. What are wholesale margins?
A. Wholesale margins are the dollars above the cost of fuel and purchased power associated with wholesale energy and capacity transactions. Xcel Energy earns wholesale margins whenever we make profitable sales into the wholesale market. Opportunities for such sales typically arise when resources dedicated to serving our retail customers exceed customer needs during a given time period (e.g., hour, day, month or season). Consequently, if we have unused
resources after meeting the needs of our retail customers, we will attempt to sell energy produced by these supply resources into the wholesale market to make a profit. The Company has engaged in these “asset-based” wholesale sales for many years.

There is another type of wholesale activity that can also create wholesale margins. This trading does not rely on generation resources typically used to meet retail load; instead, it stems from purchases and sales that we execute solely for the purpose of generating wholesale margins. This type of non-asset-based, or “proprietary commodity,” trading is relatively new, and was not present at the time of our last electric general rate case.

In this section of my testimony, I first discuss the Company’s proposal for traditional, asset-based wholesale margins, then our proposal for the treatment of this non-asset-based trading.

A. Asset-Based Trading

Q. HOW HAVE WHOLESALE MARGINS BEEN CONSIDERED IN PRIOR GENERAL RATE CASE PROCEEDINGS?

A. The Commission has reflected a credit to the retail cost of service in the amount of the anticipated test-year level of wholesale margins. The Company is then at risk for any over- or under-recoveries of this amount between rate cases. In our most recent electric general rate case (Docket No. E002/GR-92-1185), the Commission credited the Minnesota jurisdictional share of the $34.2 million total Company budget for wholesale margins to the retail cost of service.
Q. HAVE THERE BEEN ANY DEVELOPMENTS THAT WOULD AFFECT THE TREATMENT OF WHOLESALE MARGINS IN THIS PENDING GENERAL RATE CASE?

A. Yes. First, the nature of the margins themselves has changed substantially since the time of our last rate case. Second, there have been changes in the overall electricity marketplace that affect both the anticipated level of future wholesale margins and their predictability.


A. In the Company’s last general rate case, approximately $10 million of the $34 million in total Company margins were projected from short-term (one- to two-year) capacity sales to other investor-owned utilities. An additional $20 million was projected from firm energy sales primarily associated with those capacity sales, plus certain mid-term seasonal energy sales. Of the total $34 million in total Company wholesale margins in the 1993 test year, only about $3 - $4 million were attributed to projected sales into the spot energy market.

Q. PLEASE COMPARE AND CONTRAST THE WHOLESALE MARGINS IN THE 1993 TEST YEAR TO THOSE THE COMPANY EXPECTS TO EARN IN 2006.

A. As discussed by Mr. Abboud, as the electric supply needs of our customers have increased since 1993, the Company’s unused base-load resources have largely been absorbed in many load hours and the Company has increasingly relied on purchases from third parties. Since the Company is now a significant net purchaser of capacity and energy, our available resources to make wholesale sales differs significantly from 1993. As a result, the types of wholesale transactions we make have changed. For example, the 2006 test-year wholesale sales margin budget consists solely of daily and hourly short-term sales, a stark contrast to the one- to two-year transactions that
contributed to the $34 million total Company credit in the 1992 rate case. Hourly and daily sales are inherently opportunistic -- therefore less predictable - than longer-term capacity and energy sales, making it difficult to establish a forecast for a fixed credit to the cost of service that is sufficiently robust for ratemaking purposes. In addition, the MISO Day 2 Market also affects the type of short-term wholesale sales we can make. As such, I believe a fixed credit to base rates is no longer the most effective regulatory approach to the treatment of wholesale margins.

Q. WHY DO YOU BELIEVE THAT A FIXED CREDIT MAY NOT BE THE MOST EFFECTIVE REGULATORY APPROACH?

A. Because of the uncertainty surrounding a forecast of annual wholesale margins, a fixed credit would create substantial risk for both the Company and our customers. Our previous ability to derive an accurate forecast that could establish a reasonable fixed credit was primarily linked to long-term wholesale capacity sales. As such, it was relatively easy to develop a credit based on known and predictable revenue streams. Now that our wholesale sales margins are generated from very short-term sales (e.g., daily and hourly sales), sales margin forecasts are less certain. As an added complexity, our sales margin forecast is highly dependent on the prices that MISO assigns to various commercial pricing nodes. We do not have sufficient experience with MISO's dispatching of generators in different seasons and under different market conditions. After all, at the time this testimony is filed, the MISO Day 2 market will only be in its eighth month of operation.

As such, the fixed credit approach would place undue risk on both the Company and our customers: the Company would bear the risk that the credit
is set too high to achieve in the test year and beyond; ratepayers would bear the risk that the credit is set too low. Additionally, a fixed credit does not align the interests of the Company and our customers. A different approach is warranted.

Q. HOW DOES THE COMPANY FORECAST SHORT-TERM WHOLESALE MARGINS?
A. The Company relies on the same forecasting tools that we have used for the past several years, namely a production cost simulation of the operation of our system that incorporates forecasted loads, generation availability, and market prices. This simulation is performed with our PROSYM software model of the system.

Q. WHAT IS THE COMPANY'S FORECAST FOR WHOLESALE MARGINS FOR THE TEST-YEAR 2006?
A. Using PROSYM, we have forecasted wholesale margins of approximately $21.9 million, net of transmission costs, for NSP Minnesota—the Total Company in the 2006 test year, or $16.2 for the Minnesota jurisdiction. The Company's 2006 operating budget includes this margin estimate. Like any predictive production cost model, the PROSYM model relies on a large number of forecasted values, and changes in the price of power and fuel can change the model's final results. With that said, I believe the PROSYM margin forecast is the most accurate available.

A. In early September 2005, we ran an update of our PROSYM margin forecast. The purpose of this update was to test whether our forecast of $21.9 million continued to be appropriate, given that it was created in Spring 2005 and we had seen dramatic changes in energy prices. Although many model inputs had
changed from the initial margin forecast, the updated forecast confirmed the reasonableness of our test-year budgeted wholesale margins. The updated forecast of wholesale margins is approximately $1.4 million lower than the original $21.9 million total Company budget. However, given that these two model results are relatively close, I believe it is appropriate to continue to rely on the original budget estimate and the $21.9 million total Company, test-year estimate remains reasonable.

Q. HOW DOES THIS FORECAST COMPARE WITH MOST RECENT WHOLESALE MARGIN ACTIVITY?

A. It is lower. In 2003 and 2004, the Company achieved margins well above 1993 test year levels. These results stemmed in large part to historic drought conditions that allowed the Company to sell significant amounts of power to Manitoba Hydro. In addition, Summer 2004 was, on average, the third coolest on record, based on average temperature (Reference: National Oceanic and Atmospheric Administration), making higher levels of surplus generation available for us to sell to Manitoba Hydro and other counterparties. The drought in Manitoba ended in 2005, and Manitoba Hydro resumed its historic role as a large net power exporter into the United States. Therefore, I do not believe that 2003 and 2004 margin levels are in any way representative of our ability to make wholesale margins in 2006 and beyond.

A. Our 2005 budget for wholesale margins is approximately $44 million. But there are several key factors that drive our expectation for significantly lower margins during 2006, including:

- Our Emissions Reduction Project and its effect on available generating capacity for wholesale sales.
- MISO Day 2’s effect on our ability to sell spinning reserves.
- Our anticipated customer load growth. As our native load requirements increase, the amount of unused generation or long-term purchases available for short-term wholesale sales is diminished.

Q. PLEASE DISCUSS THIS FIRST KEY FACTOR.

A. Under the Emissions Reduction Project, the Company will be converting two coal-fired power plants to natural gas (High Bridge and Riverside), and a third key coal-fired plant (AS King) will be upgraded with new pollution control equipment and major boiler rehabilitation. During the implementation of this Project during 2005 - 2009, King and Riverside will be taken out of service for significant periods, making less coal-fired generation available. Our ability to make wholesale margins will be reduced by this reduction in availability, as there will be fewer hours when some of our lowest-cost generation will be available to make wholesale sales. In fact, there will be less generation available in total to make such sales. Thus, it is certain that this Project conversion will reduce our ability to make short-term wholesale sales, reducing wholesale margins in both 2006 and beyond.

Q. PLEASE EXPLAIN THE SPINNING RESERVE ISSUE AND ITS NEGATIVE IMPACT ON WHOLESALE MARGINS.
A. The Company has experienced reduced margins due to a reduction in our ability to sell "spinning reserves," reserves that must be maintained and online to respond to the reliability needs of the Company’s system. Under Mid-Continent Area Power Pool (“MAPP”) and MISO Day 1 operating rules, the Company was able to make short-term energy sales from generation designated as spinning reserves, with immediate recall rights if the Company needed to use the spinning reserves on our system. In recent years, this type of sales made up a significant portion of our total wholesale margins in any given year.

MISO’s Day 2 Market has reduced the attractiveness of this product to wholesale customers. This decline appears to stem primarily from the fact that our customers external to MISO are now subject to additional and unknown charges associated with power exports from the MISO footprint. Utilities that were consistent purchasers of spinning reserves in the past are not willing to take this new price risk, and have stopped purchasing spinning reserves from us.

Q. PLEASE DISCUSS THE FINAL FACTOR, THE EFFECT OF LOAD GROWTH.
A. Our total system load grew over the past 10 years, resulting in an average annual increase in needed generation of 75 to 125 MWs. As our load grows, fewer unused generating resources will be available for wholesale sales during many hours of the day. This trend is expected to continue, reducing our ability to make wholesale sales, at least until additional base load generation resources are added to the Company's system. Under our 2004 Resource Plan, these base load resources are not anticipated until sometime after 2012 or later.
Q. HAS THE COMPANY GENERATED WHOLESALE SALES MARGINS IN EXCESS OF THE $34 MILLION TOTAL COMPANY BUDGET SINCE THE RETAIL CREDIT WAS ESTABLISHED IN THE 1992 RATE CASE?

A. Exhibit __ (TAI-1), Schedule-4 provides a history of wholesale sales margin activity at the total Company level since 1994, the first year following the 1993 test year. In some years between 1993 and the filing of this rate case, the Company under-recovered the $34.2 million amount, and in other years it collected more. In the last few years, the Company has collected more than $34.2 million. Since 1994, the Company has averaged approximately $37 million annually in wholesale margins.

Q. IT WOULD APPEAR THE FIXED CREDIT TO BASE RATES HAS BEEN MORE BENEFICIAL TO THE COMPANY THAN TO ITS CUSTOMERS.

A. These actual wholesale margins should be considered in the proper perspective. Comparing the Company's margin activity to the fixed credit on a present value basis (1993 dollars), margin activity has fallen short of the fixed credit by approximately $14 million in real terms.

Q. GIVEN THE UNCERTAINTY YOU CITE, IS THE COMPANY PREPARED TO PROPOSE AN ALTERNATIVE TO THE FIXED CREDIT FOR WHOLESALE MARGINS?

A. Yes. Rather than rely on a wholesale margin forecast to derive an unchanging fixed credit to base rates, the Company proposes a mechanism that shares the benefits of actual wholesale sales margins through the FCA mechanism. This method reduces the uncertainty and risk to customers and Company alike, as benefits are shared as they are created.
Q. **How does the sharing of a portion of wholesale sales margins through the FCA benefit customers?**

A. I discussed earlier the increased complexity of operating in the MISO Day 2 market. It is in the customer's interest to ensure that the Company has a strong and compelling interest in managing and assuming the increased complexity and potential added risk associated with increased wholesale sales. Incentive mechanisms are designed to align the interests of the customer and the Company, encouraging behavior that is beneficial to both. They are typically designed to increase the likelihood of larger total benefits being created compared to a regulatory treatment that does not reward efficient behavior.

Q. **Do you have a specific proposal for the Commission to consider?**

A. Yes. In light of the uncertainty surrounding a test year forecast of wholesale margins, I recommend that the Commission provide no fixed credit to base rates in the cost of service. Instead, I recommend the Commission approve a sharing mechanism in the FCA that is based on actual wholesale margins as they are achieved. Specifically, I propose that ratepayers receive 100 percent of actual, asset-based margins achieved up to the $16.2 million Minnesota jurisdictional allocation of the test-year, total Company forecast of asset-based wholesale margins ($21.9 million). Once that threshold level is achieved, ratepayers and the Company would share equally in the asset-based wholesale margins earned beyond that threshold.

For example, if the Company were to earn $25 million from asset-based transactions in a single year, ratepayers would receive $20.6 million as a credit in the FCA, and shareholders would retain $4.4 million as earnings.
Alternatively, if earnings were $10 million in a single year, ratepayers would receive the entire $10 million as a credit to rates, and shareholders would retain no earnings from this activity. This sharing mechanism would operate on a calendar-year basis, with the ratepayer credits up to the threshold amount beginning in January of each year. The sharing would begin whenever the $16.2 million threshold is achieved, and would continue through year-end. While actual margins would be shared as they are achieved—on a two-month lagged basis as other fuel costs are trued-up in the FCA—the operation of the overall mechanism would occur on a calendar-year basis.

Q. WHY DO YOU PROPOSE THAT RATEPAYERS RECEIVE 100 PERCENT OF ANY WHOLESALE MARGINS UP TO $16.2 MILLION?
A. As discussed earlier in my testimony, we forecast approximately $16.2 million in asset-based wholesale margins for the test year. I believe it is appropriate for ratepayers to receive all the benefits of our wholesale activity up to that benchmark. Our rate case request includes recovery of expenses associated with the opportunity to achieve this amount. I believe it is thus appropriate for ratepayers to receive the full benefit of these expenses.

Q. WHY DO YOU BELIEVE THAT 50 - 50 SHARING ABOVE THE $16.2 BENCHMARK IS THE APPROPRIATE SHARING PERCENTAGE?
A. As I have discussed, a number of factors have combined that greatly lower our expected short-term wholesale sales margin forecasts. I would expect our sales margins to further continue to decline in the coming years. Consequently, I do not believe the margins that would be shared under this mechanism would be large. With this incentive, however, we would be encouraged to make additional investments in energy trading infrastructure or
incurred additional operation and maintenance costs at our plant sites as needed to maximize these sales. These additional costs are not reflected in our proposed test year revenue requirements. When evaluating whether to work aggressively to achieve wholesale sales margins, the Company needs to weigh the required additional costs -- which will not be immediately recovered in rates -- against the potential benefits from margin sharing. If the sharing percentage were set too low, it would discourage the Company from incurring additional costs that will be needed to maximize wholesale margins, potentially beyond the $16.2 million threshold.

Q. ARE THERE ANY OTHER REGULATORY CONSIDERATIONS WITH RESPECT TO YOUR WHOLESALE MARGINS PROPOSALS?
A. Yes, there are two. First, a variance to the Commission’s FCA rules would be required to implement our proposal. The FCA rules (Minn. Rule 7825.2390 through 7825.2600) itemize the costs allowed for recovery; under our proposed approach, the FCA would be credited with achieved wholesale margins as an offset to allowable fuel and purchased power costs. To allow for the pass-through of wholesale margin revenues, we believe a variance to the FCA rules is needed. Second, the results of the sharing mechanism need to be reflected if any refund of interim rates is issued.

Q. DOES YOUR PROPOSAL MEET THE TEST FOR A VARIANCE, AS PROVIDED BY MINN. RULE 7829.3200?
A. Yes, it does. This rule provides a three-part test for granting variances to Commission rules. My proposal meets this test:
• Enforcement of the rule would impose an excessive burden on both customers and the Company, as either party would bear excessive risk of error in the setting of a stand-alone, base rate credit.

• Granting the variance would not adversely affect the public interest; indeed, it would enhance it by ensuring that ratepayers receive an appropriate benefit from wholesale margins and the Company is encouraged to achieve higher wholesale sales.

• Granting the variance does not conflict with standards of law.

Thus, it is appropriate for the Commission to grant the variance to allow wholesale margins to be returned to customers through the FCA. The FCA tariff sponsored by Mr. Phillip J. Zins in this proceeding includes language to allow for my proposed sharing mechanism.

Q. PLEASE DISCUSS THE SECOND REGULATORY CONSIDERATION REGARDING YOUR PROPOSAL.

A. Interim rates associated with this general rate case assume the test-year budget amount of wholesale margins as a credit to the cost of service in base rates, rather than our proposal to share wholesale margins with customers through the FCA. It is my understanding that this approach is consistent with requirements for interim rates, which are established based on cost categories and approaches used in the prior rate proceeding.

If the Commission adopts my proposal, the final rates and interim rate refund should be adjusted to reflect the new approach effective January 1, 2006. Thus, when determining the interim rate refund, we would track actual wholesale margin performance and adjust as necessary from the assumed test-year budget level to credit customers the amount the sharing mechanism
would have provided given the actual level of wholesale margins that occurred while this rate case was pending. This approach most fairly bridges the transition from the base-rate credit approach previously used for wholesale margins to the new approach.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED OF SUCH A SHARING MECHANISM FOR WHOLESALE MARGINS?
A. Not to my knowledge. The reduction in longer-term sales and changed market conditions that are the basis for my recommendation against a fixed credit are relatively recent, and the Commission has not, to my knowledge, previously addressed the issue within this context.

Q. IN THE EVENT THE COMMISSION DOES NOT APPROVE YOUR PROPOSAL TO SHARE A PORTION OF WHOLESALE MARGINS, WHAT DO YOU RECOMMEND?
A. As I have discussed, it is inappropriate to assign a fixed credit to base rates in light of the uncertainty surrounding any forecast of wholesale margins. Consequently, I recommend that any treatment of wholesale margins in this proceeding be based on our actual performance in achieving wholesale margins over time and be handled in the FCA. Further, I recommend that any alternative to my proposal continue to include a margin-sharing mechanism.

Q. WHY IS THAT?
A. It is important that the Commission consider and act in light of the substantial risk to both the Company and customers of a fixed credit to base rates. By using the FCA mechanism to return wholesale margins to customers, the risks associated with a fixed credit to base rates are eliminated.
Finally, given the complexity of the current wholesale environment, I believe it is critical for ratepayer and shareholder interests to be aligned through a margin-sharing mechanism.

B. Non-Asset Based Trading

Q. You mentioned a second type of trading that can create wholesale margins, non-asset-based trading. Please describe that activity.

A. Yes. Non-asset trading is the practice of purchasing energy in the wholesale market over and above our customers' needs and reselling it for a profit. In these transactions, the Company operates much like a competitive marketer of wholesale energy. Although the introduction of centralized power markets like MISO has increased the types of transactions included in non-asset trading activities, this basic description of this activity still applies. This activity has increased due to the issuance of the Energy Policy Act in 1992, in which FERC began the active promotion of competitive energy markets and moved to provide market participants with equal access to the transmission grid.

Q. Is this market-based activity regulated?

A. Yes. This activity is regulated by the FERC. Although the sale prices are not subjected to significant regulation, the treatment of margins is regulated. The Joint Operating Agreement ("JOA"), a FERC-approved rate schedule between the Xcel Energy utility operating companies, anticipated such trading, defined in that agreement as "Non System Marketing."

Q. Please describe the JOA and its purpose.
A. The JOA was established in 2000 with the completion of the Xcel Energy Inc. merger. Its purpose is to coordinate the trading and resource acquisition activities of the Xcel Energy utility operating companies. The JOA ensures that we coordinate these activities, including non-system marketing, to the joint benefit of all of the operating companies.

Q. WHAT GUIDANCE DOES THE JOA PROVIDE REGARDING REGULATORY TREATMENT OF MARGINS GENERATED FROM THESE ACTIVITIES?

A. The JOA requires that all margins from such activity -- regardless of which utility operating company executed a specific transaction -- be pooled and allocated among the companies based on the prior year's peak demand. Once this allocation is made, the margins are subject to the applicable retail regulatory treatment of the relevant state jurisdiction.

Q. WHAT IS THE CURRENT REGULATORY TREATMENT OF THESE TRANSACTIONS IN THE MINNESOTA JURISDICTION?

A. There is no specific guidance regarding such transactions, as they were not anticipated at the time of our 1992 electric rate case. The credit to the retail cost of service adopted in our most recent electric general rate case was based on anticipated asset-based wholesale transactions. Thus, ratepayers have been unaffected by any gains or losses due to non-asset-based trading activity since the merger.

Q. IS IT APPROPRIATE FOR REGULATED UTILITIES TO ENGAGE IN NON-ASSET TRADING ACTIVITIES?

A. Yes. As discussed in Mr. Beuning's direct testimony, FERC has for many years promoted competition in wholesale markets. At present, most utilities,
including the Company, have market-based sales tariffs that allow them to make wholesale sales at market-based rates. Utilities have always actively participated in these markets, and have increased such activities as the competitive markets have matured and deepened.

The Company also has a compelling interest in full participation in the electric energy trading markets, as failure to do so would cause our customers to suffer higher costs through less informed and more costly economic purchase and operational decisions. Electric utilities that do not engage in non-asset trading activities simply do not have the same "price discovery" information available to them when they are making purchase and sale decisions. Less information in a commodity market translates into the utility paying more for purchases and receiving less for its sales. Thus, this trading activity benefits our customers by generating substantial market price intelligence that is applied to a wide variety of system marketing and operational decisions.

Q. CAN YOU PLEASE DESCRIBE HOW MARKET INTELLIGENCE FROM NON-ASSET MARKETING ACTIVITY BENEFITS XCEL ENERGY CUSTOMERS?

A. Yes. Although one of the benefits of MISO has been the increased transparency of power prices, other regional markets outside the MISO footprint do not have transparent prices, and events in these regional markets can impact the power supply prices in Minnesota. Our proprietary trading activities create price discovery in other markets that can then be used to adjust our power prices upwards or downwards.

In addition, non-asset trading allows us to be active in multiple markets on a daily and even hourly basis. This activity provides a wealth of information
concerning the outage status of generation, utility load expectations, transmission constraints, and other market fundamentals that impact price. Absent this effort, we would not be talking to these market participants daily, and our phone calls to customers and suppliers would not be treated with the same priority. In addition, these trading activities often identify beneficial opportunities for our customers. These additional trading activities provide us substantially greater knowledge of our potential economic alternatives for asset-based purchases and sales to benefit our native load. Finally, other market participants are aware of our marketing activities in areas outside of Minnesota; such knowledge serves to keep the prices they offer us in line with true market prices.

Q. CAN NON-ASSET-BASED TRADING ACTIVITIES RESULT IN LOSSES AS WELL AS GAINS?
A. Yes. Unlike traditional wholesale margins created from short-term surplus generation sales, non-asset trading can result in both positive wholesale margins and losses. While the Company has never experienced losses from this activity on an aggregate annual basis, losses can and do occur on individual transactions or during shorter-term trading periods. Accordingly, the Company maintains strict risk management policies and procedures to limit and control the risk associated with these activities.

Q. WHAT REGULATORY TREATMENT OF THIS ACTIVITY DO YOU PROPOSE FOR THIS PROCEEDING?
A. I recommend a similar sharing mechanism for non-asset trading activity. Like asset-based wholesale margins, the margins created from this activity cannot be forecast using a production cost model or any other asset-based model,
making it difficult to develop a forecast of Non System Marketing margins for
the Minnesota jurisdiction. Further, the pooled nature of these margins under
the JOA makes it even more difficult to develop a forecast, since the amounts
would depend on the activities of all Xcel Energy operating companies. A
sharing mechanism would allow the benefit of the margins actually achieve to
flow through to customers, while retaining our incentive for active and
aggressive participation in this market.

Q. WHAT SPECIFICALLY DO YOU PROPOSE?
A. I propose that the margins created by non-asset-based trading be shared
equally between customers and the Company. We would credit the FCA in
an amount of 50 percent of actual, non-asset-based margins as they are
achieved and pooled pursuant to the JOA, similar to the approach I proposed
for the asset-based margins. Like that proposal, this simple approach aligns
the interests of our customers and the Company.

Q. WOULD CUSTOMERS BEAR ANY RISKS UNDER YOUR PROPOSAL?
A. Yes. As I noted above, there is some risk of loss in this type of trading,
although we have never experienced a net loss on an annual basis. Based on
our past performance, I believe customers would experience a net benefit
from my proposal, but there is certainly risk associated with this activity.

Q. WHAT WOULD BE THE ALTERNATIVE IF THE COMMISSION DETERMINES THAT
RATEPAYERS SHOULD NOT BE SUBJECT TO THIS RISK?
A. I see two approaches. First, the Commission could adopt a modified sharing
mechanism whereby ratepayers are shielded from the risk of a net annual loss
from this trading activity. Under this approach, the Company would assume
the risk for any losses associated with non-asset based trading, as measured on an aggregate annual basis. In exchange for the Company assuming the downside risk from this activity, I believe the net annual gains should be shared 25 percent to customers and 75 percent to the Company. This approach allows the customers to realize the benefits of the market intelligence produced by this activity, share in positive wholesale sale margins, and assume no risk of losses.

The other alternative would be to find that ratepayers should not bear any risks or receive any benefits from this activity. This approach would essentially treat non-asset-based trading as a non-regulated activity. Either approach would shield ratepayers from the risks of this type of trading.

Q. WOULD A VARIANCE TO THE COMMISSION'S FUEL CLAUSE RULES BE REQUIRED FOR YOUR MARGIN-SHARING PROPOSAL FOR NON-ASSET-BASED TRADING MARGINS?
A. Yes, it would. I believe the reasoning for proposed rule variance for asset-based wholesale margin sharing also applies to non-asset-based trading margins, and a variance should be granted by the Commission to allow the shared margins to flow through the FCA.

Q. WOULD A TARIFF CHANGE ALSO BE REQUIRED?
A. Yes. The FCA tariff sponsored by Mr. Zins provides for the treatment of these margins through the FCA.
IV. RETAIL INCENTIVE

Q. YOUR FINAL ISSUE RELATES TO A POSSIBLE RETAIL INCENTIVE FOR FUEL AND PURCHASED POWER COSTS. WHY DOES THE COMPANY BELIEVE THE COMMISSION SHOULD CONSIDER SUCH AN INCENTIVE?

A. As has been discussed throughout the Company's testimony in this proceeding, the wholesale electricity and electric fuel marketplace has changed dramatically from that of 1992, the time of our last electric general rate case. Just as it is necessary to revise ratemaking treatment of wholesale margins in light of these changes, it is appropriate to begin considering whether further changes are needed. While I believe our fuel and purchased power practices are sound, I also believe it is appropriate to consider whether an agreed-upon incentive mechanism could be implemented into our existing FCA processes to encourage greater efficiencies and lower costs for our customers.

Q. HOW WOULD A RETAIL INCENTIVE MECHANISM CREATE ADDITIONAL EFFICIENCIES AND LOWER COSTS?

A. As I mentioned in my discussion of wholesale margins, there are benefits to aligning the interests of customers and the Company. Incentive mechanisms reward the Company for actions that are successful in lowering customer costs. With respect to the FCA, while I believe our fuel and purchased power procurement practices are prudent and effective, I also believe that incentives may be appropriate and achieve even better results. Incentives encourage the utility to take reasonable risks or incur additional costs that the Company may not otherwise undertake, actions that may result in lower overall costs for customers. Given the significant costs recovered through the FCA and the dramatic changes in the market environment, it is more challenging to
develop an appropriate incentive for these types of costs. Nonetheless, I believe it is appropriate to consider whether an incentive mechanism could be developed that creates benefits for both customers and the Company.

Q. **DOES THE COMPANY HAVE ANY EXPERIENCE WITH AN INCENTIVE ON FUEL OR PURCHASED POWER COSTS?**

A. Yes. PSCo, another utility operating company subsidiary of Xcel Energy Inc., has operated for several years under an incentive mechanism called the Energy Cost Adjustment ("ECA"), approved by the Colorado Public Utilities Commission. This mechanism rewards PSCo when fuel and purchased power costs are lower than threshold levels and penalizes PSCo with costs are higher than thresholds. Under this mechanism, a variety of factors -- including increased power plant performance or changed fuel procurement practices -- can affect the ultimate cost to customers, and thus the potential for reward. The mechanism is rather complex and subject to a variety of caps and parameters, but is generally designed to align utility and customer interests and create incentives for lowering costs.

Q. **WOULD SUCH A MECHANISM BE APPROPRIATE IN MINNESOTA?**

A. Possibly; however, it is difficult to say without additional analysis. There are unique aspects of every utility system that makes replication of a specific incentive difficult. Issues such as the system's fuel mix and available resources need to be considered in the design of the mechanism to ensure it provides incentives in areas where there is the potential to create benefits and implement the actions the state wishes to encourage. In addition, a Minnesota mechanism would need to be designed considering the implications of the Day 2 Market, which is still evolving, and the Company's
extensive Conservation Improvement Programs ("CIP"). We would not want the retail fuel and purchased power incentive to somehow operate in a manner inconsistent with CIP programs or the Company's existing CIP incentive mechanism.

That said, as evidenced by the Commission's interest in additional information regarding fuel and purchased power procurement and the detailed review of our monthly fuel clause filings by the Department, there is clearly interest in ensuring that costs are prudently incurred and reasonable for recovery from customers. While such review is appropriate, an incentive mechanism is also useful as it aligns the interests of the utility and its customers, thus providing better assurance that all reasonable actions are being taken to lower costs. We raised this issue in comments filed in our pending application to recover MISO Day 2 costs through the FCA (Docket No. E002/M-04-1970), and continue to believe it is appropriate for exploration.

Q. DO YOU HAVE A SPECIFIC PROPOSAL TO ADVANCE?

A. Not at this time. However we have identified some options that warrant exploration with the Commission and parties, including: (1) an incentive for power plant performance that encourages reductions in forced outage rates, and (2) an incentive to incur additional risks through more aggressive economic purchase practices. Such exploration may best occur within the context of the Commission's pending inquiry into the continuation of the fuel clause (Docket No. E999/CI-03-803) or another separate process. Given the complexity of the issue, I believe this approach is preferable to attempting to develop such a mechanism within the instant proceeding. The Company's
experience in Colorado with incentive mechanisms was that it took
stakeholders a significant amount of time to develop and become comfortable
with the approved mechanism. In any event, the Company would be
interested in working with the agencies and other parties on this issue and
developing a proposal for the Commission's consideration.

Q. ARE THERE ANY OTHER ISSUES THE COMMISSION SHOULD CONSIDER WHEN
DECIDING WHETHER TO PURSUE A RETAIL INCENTIVE MECHANISM?
A. Yes. Regardless of whether a retail incentive mechanism is pursued, I believe
the changing market only increases the continued need for a fuel and
purchased power recovery mechanism. Our system continues to grow --
adding to costs -- and fuel prices have dramatically increased. Without a
mechanism for recovering such costs from customers, the Company would
clearly not recover our prudently incurred costs. While an incentive
mechanism around these costs would be appropriate to explore and perhaps
implement, it should not be viewed as a replacement for timely and fair
recovery of our fuel and purchased power costs.

V. SUMMARY AND CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS PROCEEDING.
A. I believe the Commission must take a new approach to the treatment of
wholesale margins in our rate case, given the considerable uncertainty
surrounding any forecast of test year margin levels and the evolving wholesale
electricity marketplace. This new approach should be based on our actual
performance in achieving wholesale margins and be based in the FCA rather
than base rates to allow for timely pass through to customers. I further
believe it is important that the approved mechanism align the interests of customers and the Company through sharing. Any approach adopted by the Commission should be consistent with these general principles.

Consistent with this context, I recommend the Commission approve my sharing proposals for wholesale margins. Specifically, the Commission should provide that ratepayers obtain 100 percent of the benefits of the achieved asset-based margins up to $16.2 million and 50 percent of any additional margins. The actual amounts realized would be shared in this manner through the FCA. With respect to non-asset-based trading, I recommend that the Commission approve a 50 - 50 sharing mechanism within the FCA for all realized margins, following application of the JOA. Finally, I recommend that the Company begin discussions with interested parties work to determine whether an appropriate retail incentive mechanism can be developed for submittal to the Commission.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?
A. Yes, it does.
Thomas A. Imbler  
Vice President, Commercial Operations  
Xcel Energy Services Inc.  
30 Denver Place  
1099 18th Street  
Denver, CO 80201

EDUCATION

Masters of Business Administration  
Washburn University, 1998

Bachelor of Science, Mechanical Engineering  
Wichita State University, 1986

PROFESSIONAL DEVELOPMENT

Currently serving as Xcel Energy’s board member alternate for the Center for Energy and Economic Development (CEED).

Served as a member of the Western Systems Power Pool’s Executive and Operating Committee.

Testified before the Texas and Colorado regulatory commissions on various topics over my career.

EXPERIENCE AND CURRENT RESPONSIBILITIES

February 2004, Vice President, Commercial Operations. In addition to my prior responsibilities, I became responsible for coal, natural gas, and oil procurement, origination, and Xcel Energy’s market development activities.

December 2002, Managing Director, Energy Trading. In this position, I was responsible for electric trading activities and the optimization of the Public Service of Colorado (PSCo), Southwestern Public Service Company, NSP (Minnesota), and Northern States Power Company (Wisconsin) generating assets and purchased power contracts.

September 2000, Director, Energy Trading, XES. Upon completion of the Xcel Energy merger, I became Director, Energy Trading, for XES and my responsibilities included energy trading and system operations for PSCo and Southwestern Public Service Company.

August 1998, Manager, Energy Trading, NCS. I began working for New Century Services, Inc. ("NCS"). NCS was the service company affiliate of PSCo when it was a wholly-owned subsidiary of New Century Energies, Inc. and was renamed Xcel Energy Services Inc. upon the completion in August of 2000 of the merger of New Century Energies, Inc. and Northern States Power Company.
Company ("NSP"), which resulted in the creation of Xcel Energy Inc. In this capacity, I had responsibility for managing the Public Service system.

1995, Manager, Wholesale Marketing. I was responsible for all wholesale marketing activities, including trading, origination, scheduling, and risk management.

1992, Manager, Wholesale Customer Sales, Western Resources Corp. Western Resources, now called Westar, acquired Kansas Gas and Electric, and I became Manager, Wholesale Customer Sales, responsible for marketing to Western Resources’ wholesale customers.

1986, Nuclear Licensing Engineer, Kansas Gas & Electric Co. I began my career with Kansas Gas and Electric in 1986 as a Nuclear Licensing Engineer. Later that same year, I moved to Marketing in 1986 as a Commercial/Industrial Consultant and became an Industrial Sales Engineer in 1989. In both of these positions I worked with commercial and industrial customers.
Summary Description of the Fuel and Purchased Power Procurement Activities of Xcel Energy Trading Unit

This Schedule provides information regarding the Company’s natural gas and coal procurement activities for use in our electric generating plants. The Direct Testimony of Mr. Camille A. Abboud presents information regarding the costs of various resources as recovered through the Fuel Clause Adjustment ("FCA"). In addition, the Direct Testimony of Mr. Stephen J. Beuning presents detail on the Midwest Independent Transmission System Operator, Inc. ("MISO") and the implementation of the MISO Day 2 Market. This Schedule presents information related to how Xcel Energy participates in that market through daily and seasonal planning and acquisitions strategies.

A. Fuel Acquisition

1. Natural Gas

The Gas Supply group performs the following functions:

- **Planning**  The Gas Supply group plans for the fuel requirements of our natural gas-fired generating units, including Black Dog, Blue Lake, Angus Anson and the NSPW Wheaton plants. The Gas Supply group evaluates each plant's forecasted fuel requirements on an annual, monthly and daily basis to determine the amount of gas required. These requirements are then compared to the contracted transportation and balancing services to determine the amount and type of gas and transportation to be purchased.

- **Acquisition**  This group purchases, schedules and balances all of the natural gas and fuel oil to operate the Company's generation fleet. This function involves purchasing gas at multiple receipt points, managing storage injections and withdrawals, making timely and intra-day nomination on multiple pipelines and having personnel available on-call 24 hours a day, seven days a week. Such round-the-clock coverage is needed to maintain compliance and avoid imbalance penalties set forth in upstream pipeline and local distribution company ("LDC") tariffs as the electric system's dispatch -- hence natural gas use and needs -- changes throughout the operating day.
Third-Party Negotiations. Our Gas Supply personnel identify new
counterparties for purchasing natural gas, look for opportunities (such as
capacity release) to fully use the firm transportation service that has been
contracted for deliveries to our generation fleet, and resolve
measurement and accounting discrepancies with counterparties and
pipeline, storage service and LDC providers.

Services to Gas Utility Operation. The Gas Supply group performs these
same functions for the Company's retail gas LDC function, but the LDC
function maintains separate gas supply, pipeline transportation and
storage contracts to ensure correct cost allocation to each function.

Nearly all of the gas purchased by the Gas Supply group for the Company's
generating plants is purchased with the pricing based upon third-party price
indices. We negotiate our balancing supplies, or "swing" gas needed to provide
our generating stations with operational flexibility, with multiple sellers to
ensure that we receive the lowest price.

There are three primary ways in which the Gas Supply group can lower the cost
of natural gas used in our generating stations:

Select from multiple suppliers surveyed to ensure a best-cost gas supply to meet plant
requirements. However, if the plant is called on after the start of the Gas
Day (9:00 a.m. CCT), there may be only one supplier that has gas
available; in that case, we negotiate the lowest price as compared to the
other generation opportunities that are available.

Manage our firm gas transportation service. Having firm transportation service
ensures that we maintain the rights to flow gas to our generating plants
at all times, providing the operational flexibility needed for those
facilities. However, this transportation service can also be resold (i.e.,
capacity release) to other market participants on a recallable basis. The
capacity release generates revenues to reduce the total cost of holding
the capacity, but the ability to recall the transportation capacity ensures
that the plants retain first call on the capacity to meet the energy supply
requirements of our electric customers. Any revenues from capacity
release are returned to ratepayers through the FCA in a manner similar
to the flow-through of capacity release revenues generated for the Company's LDC function in the Purchase Gas Adjustment (“PGA”).

- **Make use of unused firm transport to capture favorable price spreads between markets.** In this case, we make gas sales at points in which the market price of gas is high enough to cover our purchase costs and any incremental costs associated with the transportation of our gas to the higher priced market. Any gains from this resale activity are returned to the electric customers through the FCA in the form of lower natural gas fuel costs.

Looking forward, the Gas Supply group is making arrangements to supply natural gas to the Mankato Energy Center and the Invenergy projects. Our purchased power agreements (“PPAs”) with these projects are based on “tolling arrangements” where the Company will purchase the natural gas for the third party electric generation (so the Company can control the fuel costs) and then purchase the electrical output of the plants. The Commission approved these PPAs in Dockets No. E002/M-04-451 and E002/M-04-1426, respectively. We will be also beginning to arrange gas supply for the High Bridge and Riverside plants. Pursuant to the Settlement Agreement approved by the Commission in that proceeding, we will also be developing a plan for consideration to hedge and perhaps implement a Performance-Based Regulation approach to gas supply for these two Company-owned plants (Docket No. E002/M-02-633). We will be filing the options for such a plan in 2007.

2. Coal and Other Solid Fuels

The Coal Supply group performs the following functions:

- **Plan and acquire coal to ensure adequate supplies for our coal-fired generating facilities.** Because power plants are generally designed to burn a certain type and quality of coal, not all coals can be burned in our plants. The coal used at the Company plants is mined in Wyoming and Montana. We use the PROSYM production cost model to forecast the quantity of coal that will be required each year. This analysis is plant-specific, as some of our plants operate at higher capacity factors than others. We

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1. While the text refers to coal, the Coal Supply group acquires all solid fuels for the Company. Solid fuel can be coal, petroleum, coke, biomass or municipally sourced refuse derived fuel.
perform this analysis annually (and more frequently as needed) to
provide the basis for our coal acquisition and transportation strategy.

- **Arrange for the transportation of such fuels to our generating plants.** Once the
  acquisition strategy is completed, we develop a plan for transportation of
  the coal to the various generating plants. We generally purchase coal
directly at the mine and assume responsibility for arranging
  transportation to our generating stations. After considering current and
  anticipated railroad service cycles, we determine the required number of
  railcar train sets to transport the purchased coal. These railcar train sets
  may be owned by Xcel Energy, provided by the railroad, or leased from
  third parties. Our rail carriers, Burlington Northern Santa Fe and Union
  Pacific, direct the movement of rail cars. Our rail contracts ensure that
  sufficient coal can be delivered to our power plants. Although the rail
  carriers control the day-to-day movements of train sets, we actively
  monitor and request adjustments as needed to train schedules.

- **Market and dispose of combustion by-products.** Coal combustion produces
  several by-products, such as fly ash and scrubber materials. The Coal
  Supply group conducts a technical and commercial assessment of these
  by-products to determine whether they can be sold, or require disposal.
  This is an on-going process, as the types of by-products created depend
  the type and quality of coal being burned. Potential markets for such
  products are changing as well. While the primary customers for these
  products are cement manufacturers, we are working with a variety of
  manufacturers to determine if our materials can be used in their
  processes. Should we be able to sell these by-products, it eliminates
  disposal costs that would otherwise be incurred. If we are unable to sell
  these combustion by-products, we typically dispose of them in landfills.

The price of coal has been historically relatively stable, but coal is evolving into
a commodity that is traded similar to electricity and natural gas. Its price has
become more volatile as supply and demand has become more balanced,
leaving less spare capacity in coal production and rail transport capabilities.

Although there are some third-party price indices for coal, most coal is still
purchased under longer-term, fixed-priced contracts. We review third-party
price forecasts and published price indices to develop a comprehensive view of
forward coal prices. We secure our coal supplies through bidding and bilateral
negotiations. In some cases, the cheapest supply alternative for our customers is to purchase coal through the short-term over-the-counter ("OTC") market, in which coal brokers match up buyers and sellers anonymously.

B. MISO Participation

1. Overview

In the Day Ahead market, Xcel Energy must submit daily price "offers" to sell energy from generation facilities on a unit-by-unit basis for each hour of the upcoming day. These generation price offers include the operating parameters of the generating facilities, such as minimum loading levels, start-up costs, and other costs (e.g., fuel) associated with unit operation that become part of the generation offers. Xcel Energy must then submit similar price "bids" to purchase energy to meet our customer needs at each "node," or predefined delivery point.

MISO's computer systems then evaluate each bid and each offer over the entire MISO regional footprint to provide an optimized Day-Ahead commitment of generation units needed to meet load obligations. These Day-Ahead generation commitments are financially binding, and participants are penalized for even small deviations from these commitments. Load bids and generation offers must be both accurate and timely to ensure compliance with the MISO Transmission and Energy Markets Tariff ("TEMT") and posted "business practices" or market rules.

We employ a conservative bid/offer strategy that is consistent with the Department of Commerce ("Department") recommendations in the Company's pending MISO Day 2 Cost Recovery proceeding (Docket No. E002/M-04-1970). First, we consistently bid our forecasted load for each hour of the Day-Ahead market. This strategy minimizes the exposure to volatile real-time prices for the variation between predicted load and actual load. Second, we offer to the market all of our low-cost, base load generation at cost. This approach increases the probability that such generation will be dispatched by MISO and will be available to serve our native load customers. We also offer our gas-fired units at our cost if we expect they will be needed for our native customers. This overall strategy minimizes our customer's overall exposure to volatile hourly prices from MISO.
As discussed by Mr. Beuming, MISO, the Company, and other market participants have experienced some unanticipated effects of Day 2 operations, such as the greater-than-anticipated dispatch of relatively high-cost, gas-fired peaking plants. As MISO improves its Day 2 Market operations, and we gain additional experience with the actual operation of MISO's Day 2 Market, we expect to find opportunities to further reduce costs for our customers.

2. **Bi-lateral Agreements**

While most short-term purchases and sales of electricity now occur in the Day 2 Market, utilities may still arrange bi-lateral sales or purchase agreements to supply customers' needs. The Company continues to purchase under pre-existing long-term power supply agreements, such as the new agreement with Manitoba Hydro and our PPAs with renewable energy (wind, biomass) generators. We are also still able to acquire some short-term energy in this fashion, analogous to our historic "economy energy" purchases. However, the quantity of such energy obtained from the short-term bilateral market has been greatly reduced by the quantity of energy purchased directly from MISO. Generally, market participants are currently more willing to sell into the broad market than make bi-lateral arrangements, and the presence of the market provides clear price signals that market participants are likely to follow even in bi-lateral arrangements.

3. **Annual, Seasonal, and Daily Planning and Trading**

The Trading group surveys the energy markets to determine if there is power available at a cost less than our forecasted cost of generating the energy ourselves. If so, we purchase the energy in an effort to lower costs and minimize our customers' exposure to volatile daily and hourly prices. We perform this function on a seasonal, monthly, and even daily basis. We staff the Trading operation all day, every day because we dispatch plants continuously as loads change and as unit availability changes.

Our process begins with an energy load forecast for the relevant period. We then use the PROSYM probabilistic dispatch model to forecast the costs of serving this load. PROSYM is a production cost simulation model that can predict, based on a series of assumptions related to load and resource costs, the fuel and purchase power costs we will incur to meet our future native load requirements. PROSYM optimizes the dispatch of generation and purchase...
power to minimize the costs of serving native load. After serving native requirements, PROSYM will dispatch unused resources (our own generation or long-term purchased energy) for sales into the wholesale market, provided such sales provide economic benefit to the NSP system. Thus, for any given set of assumptions regarding load and resource cost and availability, PROSYM is capable of forecasting both the total and incremental cost of meeting our load requirements.

We use PROSYM’s estimate of “avoided costs” for different quantities and periods as a “price signal” to our trading group to evaluate potential economic power purchases. That is, whenever we can purchase forward energy at a price below the avoided cost signal (e.g., the cost of producing the energy ourselves), we can expect to lower the total costs of serving our customers. The Trading group works to make purchases that provide customers the lowest possible costs, while ensuring reliability and the flexibility to manage the system. We undertake this activity continuously, as we are typically looking to acquire energy supplies for up to a year in advance of consumption.

Due to the potential for extreme weather, there is greater load and price volatility in the summer season. We address this potential volatility by making strategic purchases to lock-in prices for our customers. It has become difficult to get counterparties to commit to fixed price contracts since the start of the MISO Day 2 markets. However, with additional time and experience, we expect to see an increased willingness by counterparties to offer fixed price contracts for the summer season.

4. Daily Planning and Trading

Our daily planning and trading activities make up a significant portion of the Trading group’s activity. Despite efforts to prepare well in advance for all contingencies (weather, unit outages, etc.), it is not possible to prepare for all possible load and resource outcomes prior to their occurrence. For example, if our long-term plan assumed the availability of supplies (say 300 MW) from a specific coal-fired power plant, but the plant experiences a forced outage and will be out for an unexpected repair for two weeks, we need to quickly arrange replacement power. MISO’s Day-Ahead and Real-Time Markets offer the opportunity to ensure that we have acquired sufficient resources for our customers and that such resources are the most economic that the market has
to offer. The Trading group performs several functions within these markets to meet this goal.

For the Day-Ahead Market, we begin with an hourly forecast of our loads for the next day. The Trading group has an on-site meteorologist who issues the initial load forecast by 5:00 AM. We update this forecast several times a day as new data becomes available. Analysts within the Trading group then use a unit-commitment/economic dispatch model to determine the optimal resource commitment (both owned generation and purchased power) to meet the forecasted customer load. We also use this model to calculate a day-ahead forecast of avoided cost. Similar to the monthly and seasonal avoided cost calculations discussed above, the day-ahead avoided cost calculation is an estimate of our cost of producing power ourselves. Trading personnel then work with counterparties to purchase energy at prices below these avoided cost calculations.

With respect to the Real-Time Market, the Trading group remains ultimately responsible for the real-time dispatch of all generation facilities and long-term purchase power agreements even though MISO coordinates dispatch orders across its regional footprint. Because MISO does not have direct operational control over our generation fleet, we retain important control area operational responsibilities that are separate and distinct from the functions performed by MISO. We must manage these functions on a real-time basis to ensure reliability and to reduce the cost of our customers.

MISO's hourly or Real-Time Markets are similar to the Day-Ahead Markets in that MISO has the ability and authority to “clear” the market by accessing resources across its entire regional footprint. Participants with generation resources can offer units into this market on an hourly basis. However, unlike the Day-Ahead Market, participants have less ability to hedge their decisions with financial tools such as Financial Transmission Rights (“FTRs”). As such, the risks of participating in real-time activity can be greater than participation in the day-ahead markets; hence, we employ a conservative bid/offer strategy to minimize our participation in the Real-Time Market to the extent possible.
### NSP Historical Wholesale Margins

#### Total Company

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Average (93-'04) $ 37,117

T = Test Year 1993 Budget data  
A = Actual Year data

Column (3), (4) & (7) from Sales Summary

1. Option Revenues, account E456 are included within the Energy and Demand Revenues, other minor differences are due to rounding and timing of journal entries.
2. Incremental costs were adjusted by $7,480 in 1999 to reflect MAPP refund in the appropriate year.
3. Includes Wholesale transmission demand costs and option expenses and joint use revenues.