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BEFORE THE
MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
100 Washington Square, Suite 1700
Minneapolis, Minnesota 55401-2138

FOR THE
MINNESOTA PUBLIC UTILITIES COMMISSION
127 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

In the Matter of the Petition of Excelsior Energy Inc. and Its Wholly-Owned Subsidiary MEP-I, LLC For Approval of Terms and Conditions For The Sale of Power From Its Innovative Energy Project Using Clean Energy Technology Under Minn. Stat. § 216B.1694 and a Determination That the Clean Energy Technology Is Or Is Likely To Be a Least-Cost Alternative Under Minn. Stat. § 216B.1693

PREPARED REBUTTAL TESTIMONY AND EXHIBITS OF EXCELSIOR ENERGY INC. AND MEP-I LLC

ANDREW D. WEISSMAN

OCTOBER 10, 2006

EXCELSIOR ENERGY, INC.

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

PREPARED REBUTTAL TESTIMONY OF

ANDREW D. WEISSMAN

I. QUALIFICATIONS

Q Please state your name, current employment position and business address.

A My name is Andrew D. Weissman. I am a Senior Managing Director for FTI Consulting Inc. ("FTI"). My business address is 1201 I Street NW, Washington D.C. 20005.

Q Have you previously submitted testimony in this proceeding?

A Yes, I have. On June 19, 2006 I submit testimony in this proceeding on behalf of Excelsior Energy Inc. ("Excelsior").

Q Please describe your background as it relates to this proceeding.

A Throughout my career I have been involved in the evaluation of environmental regulatory frameworks and utility power supply planning and I have extensively analyzed fossil fuel markets. I have also directed major reviews of the prudence of utility decision-making and also helped to pioneer the market for trading of emissions credits in the U.S. Finally, I also drafted one of the first state statutes in the Midwest providing a specific mechanism for state regulatory commission review and pre-approval of expenditures for clean coal technology. During the past two decades, and in particular following the implementation of the Clean Air Act of 1990, environmental regulation has had a marked impact on fuel markets. During the past decade I also have followed closely how greenhouse gas emissions control policy has been evolving worldwide.

Q How does your experience relate to this proceeding?

A Considerations of environmental policy, power supply planning, the response of fuel markets, and fuel price uncertainty are vital aspects of this proceeding. My expertise is precisely focused on these particular areas of inquiry.

II. SCOPE AND ORGANIZATION OF TESTIMONY AND SUMMARY OF FINDINGS

Q On whose behalf is your testimony submitted?

A My testimony is submitted on behalf of MEP-I LLC and Excelsior Energy Inc. (collectively "Excelsior"), the developers of the Mesaba Energy Project (the "Project").

Q How is your testimony organized?

A My testimony is divided into two sections:

- Section III discusses the flaws in the analysis presented by expert witness Elizabeth M. Engelking on behalf of Northern States Power Company ("NSP") d/b/a Xcel Energy ("Xcel"), who assesses the potential impact on system costs of the proposed Purchased Power Agreement ("PPA") for Mesaba. I go on to address certain additional factors that I believe must be considered in order to properly assess these costs and evaluate the potential costs and benefits of the Mesaba Project to energy users in Minnesota.
- Section IV discusses specific assumptions that should be evaluated regarding potential fuel price volatility, potential new environmental requirements and other factors that are relevant in evaluating system costs. This Section then describes the specific range of scenarios that I believe need to be modeled as part of any properly conducted assessment.

Q What have you done to prepare your testimony?

A I have studied Ms. Engelking's Direct Testimony and Schedules, as well as the Direct Testimony and Schedules of Xcel witness Mark. A. Hervey and any associated work papers provided with the testimony, including the output files from their efforts in Xcel's various integrated resource plans ("IRP"). I have also researched and studied various other NSP IRPs and annual filings submitted over the last few years. I have worked closely with ICF Consulting ("ICF") to define and evaluate various modeling scenarios that I discuss in my testimony.

Q Please summarize your findings.

A My testimony reaches three principal conclusions:

1. NSP's analysis of the impact of Mesaba on system costs is deeply flawed, and has no probative value for this proceeding;
2. A properly conducted analysis demonstrates that prompt completion of the Mesaba Project offers compelling benefits for NSP's customers in Minnesota;
3. NSP should proceed forward immediately, therefore, with both Mesaba units.

Q Do you believe there is an urgent need to proceed forward with the Mesaba Project, if possible on an accelerated basis?

A Yes, I do.

Q What creates this urgent need?

A Due in part to NSP's growing dependence upon gas-fired generation, NSP and its customers are far more exposed to severe price spikes, due to potential increases in natural gas prices, unexpected outages at the Company's nuclear or coal units, and other factors (such as continued hotter-than-normal summers or failure of DSM or renewable energy programs to achieve their goals) than NSP's witnesses in this proceeding appear to recognize. These price spikes could easily result in hundreds of millions of dollars in increased costs to NSP's customers in Minnesota in a single year, and could result in several billion dollars in increased costs over the course of the next decade. In addition, there is a significant potential for major changes in environmental requirements, which could add dramatically to NSP's costs of serving its customers, potentially beginning early in the next decade. Further, if NSP fails to prudently plan for these contingencies, it could be precluded from fully recovering its costs – which could have serious financial consequences for the Company.

From a resource planning standpoint, therefore, there is an urgent need for NSP to immediately develop a well conceived plan to reduce its customers' exposure to these risks. NSP's filings in this docket provide little indication that it is focusing on these issues – even though their importance is well known within the industry.

If NSP were attempting to develop a plan to address these issues, I believe it would quickly conclude that it should be taking all reasonable steps to move forward as rapidly as possible with both Mesaba units – rather than trying to create roadblocks to the creation of a project which is likely to greatly benefit the State, NSP's ratepayers and Xcel's shareholders.

III. XCEL'S FLAWED SYSTEM IMPACT ANALYSES

Q In your judgment, has NSP's properly assessed the impact of the Mesaba PPA on system costs?

A No. Although Ms. Engelking's testimony provides a system impact analysis of the Mesaba PPA, the analysis is based on inappropriate assumptions and cannot be relied upon. I find that the analysis is seriously flawed in at least two major respects:

First, Xcel appears to have made numerous technical errors in its analysis of the costs of pursuing different resource plans. The effect of these errors is to significantly overstate the likely cost to Xcel and its customers of a resource plan that includes the Mesaba PPA and to significantly understate the likely cost of Xcel's proposed alternative plan. These errors include: (i) using unreasonably low future natural gas prices; (ii) understating the likely cost of alternatives to building Mesaba; and (iii) including unnecessary resources in its proposed Mesaba expansion plan.

Second, the basic methodology Xcel uses to compare alternative resource plans leaves much to be desired. Among other short-comings, Xcel: (i) examines only one set of assumptions regarding load growth, natural gas prices and other key factors; (ii) fails to make any systematic effort to take into account natural gas price volatility or other major uncertainties that might affect its plan, even though these factors could expose its customers to hundreds of millions of dollars per year in increased costs; (iii) makes no attempt to identify major risk factors facing NSP or its customers or to evaluate the extent to which different resource planning decisions might reduce the exposure of NSP and its customers to these risks; and (iv) assumes that there will be no material changes in environmental requirements at any time during the period covered by its analysis.

Further, Xcel commits these errors even though: (i) the assumptions Xcel has used regarding natural gas prices in other dockets before the Commission in recent years (which generally are similar to those it appears to be using in this proceeding, although we cannot be sure given they are not available for review) repeatedly have proven to be far off the mark – resulting in resource commitments over the past several years that are likely to result in billions of dollars in potentially avoidable costs for NSP and its customers in future years; and (ii) Xcel's assumptions regarding natural gas prices appear to be inconsistent with the Company's own publicly-stated position regarding the likely relationship between the future price of natural gas and the price of oil.

The effect of these errors (some of which are discussed principally by other witnesses) is to paint a fundamentally misleading picture of the potential costs and benefits of the decision regarding whether to enter into the Mesaba PPA. Moreover, the combination of the errors and an insufficiently sensitized system impact analysis do not result in a prudent resource evaluation sufficient to draw any conclusions about the benefits of the Mesaba PPA to Xcel's ratepayers.

Q How serious are these flaws?

A In my judgment, the flaws in Xcel's analysis raise serious issues as to whether Xcel's resource planning process is consistent with the requirements for sound resource planning. Further, these deficiencies in Xcel's planning process are particularly troubling since: (i) Xcel already should be well aware that the natural gas price forecasts it has used in the past have proven to be unreliable; (ii) Xcel has acknowledged in previous filings before the Commission that it might be beneficial to add new baseload coal-fired resources to its NSP system as early as 2011; and (iii) during the period since reaching this conclusion, Xcel appears to have taken only limited steps, beyond looking at conceptual cost estimates, to add coal-fired capacity to NSP's system.

Q Could these actions result in significant harm to NSP's customers?

A Yes, they could. As a result of its failure to take action to protect its customers against readily-foreseeable increases in the price of natural gas, NSP is now locked into a resource plan which, at least near-term, dramatically increases its exposure to potential further increases in the price of natural gas. During the period between 2003 and 2015, use of natural gas to generate electricity for NSP's customers is expected to increase dramatically, even under a relatively favorable scenarios – and could increase further in years in which load growth is higher-than-expected, summers are hotter-than-normal, or one or more of NSP's existing nuclear or coal-fired units does not operate at expected levels.

As discussed further in Section IV of my testimony, in which I discuss potential future increases in natural gas prices, it is entirely possible – perhaps even likely – that, during the next decade, higher natural gas costs will increase costs to NSP's customers in Minnesota by as much as $250 to 500 million in a single year, over and above the levels that Xcel estimated at the time of its earlier filings with the Commission. In addition, during the course of the next decade, it would not be surprising if the increase that already is expected to occur in NSP's dependence upon gas-fired generation leads to billions of dollars in previously unanticipated costs. Any of these events could have a brutal impact on NSP's customers. And, if there is ever any question at any point regarding NSP's ability to flow through these costs to its customers, it could quickly affect the credit-rating of the company. I believe exposing NSP's customers to these risks is unacceptable, and as I describe below, a proper system impact analysis clearly shows these risks and that the Mesaba PPA provides a means to manage these risks.

Q Has Xcel acknowledged the importance of attempting to minimize NSP's dependence upon gas-fired capacity?

A Yes, it has, albeit in a very limited way. The proposed NSP resource plan presented in the Engelking Direct Testimony relies heavily on the addition of coal-fired capacity beginning in 2015 – the earliest date on which the Company apparently believes it can build a new coal-fired generating unit of its own. This reflects, at least implicitly, the Company's recognition of the potential importance of adding additional coal-fired capacity to its system and reducing dependence upon natural gas.

Q Is this a satisfactory solution?

A No, it is not. As a practical matter, Xcel's approach to resource planning for NSP is creating the worst of both worlds. By failing to anticipate possible future increases in prices for natural gas, and not acting in a timely manner to add needed baseload coal-fired capacity to its system in Minnesota, Xcel increasingly is being forced to consider the addition of gas-fired generation that would not otherwise be needed on NSP's system. This generation includes both combined cycle units and combustion turbines, either built directly by NSP or procured through purchase power agreements with third parties.

Including both purchased power commitments and the MERP project, Xcel already has asked NSP's customers to effectively fund close to $2 billion in new gas-fired capacity. If NSP fails to enter into the Mesaba PPA, however, there is a substantial likelihood that it will continue adding a large number of otherwise unneeded gas-fired units, dramatically increasing its customers' exposure to higher prices for natural gas.

Over time, this is likely to result in huge cost increases for NSP and its customers and could seriously impede economic growth in the State.

Q Please explain.

A As discussed more fully below, over the next five to ten years, if Mesaba is not built, NSP's customers are likely to be asked to help finance the construction of a continuing series of new gas-fired units – a significant portion of which might not be needed if a modest amount of coal-fired capacity is added to NSP's system in a timely manner, consistent with that expected in recent years' integrated resource plans. Construction of these gas-fired units could result in the needless expenditure of hundreds of millions or even billions of dollars, and lock NSP into burning increasing quantities of the highest-priced fuel used on its system.

Further, if NSP then succeeds in eventually adding at least some additional coal-fired capacity to its system, some of these gas-fired units may operate at relatively low capacity factors for extended time periods. When this occurs, NSP's customers could, in effect, be required to pay twice for the deficiencies in Xcel's planning process – i.e., first in the form of high cost energy for extended time periods, and then for the fixed costs for under-utilized gas-fired generation. The burden this could place on NSP's customers over the planning horizon that is relevant to Mesaba is potentially huge – i.e., potentially reaching several billion dollars.

Q Are there additional impacts?

A Yes. The potential adverse impacts of NSP's growing dependence upon natural gas as a fuel to generate electricity are not limited to NSP's electricity customers. In addition, NSP's increased use of natural gas as a fuel to generate electricity also could put significant increased pressure on the natural gas supplies available to serve other natural gas users in the State.

Q How do NSP's evolving IRPs impact Minnesota's reliance on natural gas?

A As shown in the testimony of Mr. Cavicchi, NSP's IRPs have been showing an unexplained increased reliance on natural gas during a time period where natural gas prices have risen and become more volatile. This increased reliance on natural gas causes NSP's estimated consumption of natural gas compared to statewide total estimated gas consumption to increase significantly during the next several years. For example, as the Minnesota Department of Commerce reported in Direct Testimony (Docket No. E002/CN-05-123, DOC Exhibit No.__(MFG-8), Page 3 of 12) filed on November 18, 2005 in relation to NSP's Certificate of Need filing for spent fuel storage at Monticello, we see NSP's gas consumption projected to grow quickly from 2-3% of the state wide total in recent years to over 10% of the statewide total by 2010, even in years in which weather matches long-term climatological norms and coal and nuclear generation has reasonably good availability. In years in which load growth is higher, summer weather is significantly hotter-than-normal and/or one or more coal or nuclear units is out of service for extended periods, NSP's share of statewide natural gas consumption could grow dramatically.

Thereafter, as the Exhibit shows (depending on assumed available electricity generation facilities) the consumption will continue to rise at a growth rate of 5-6% per annum reaching more than 20% of the statewide total in another decade. Moreover, as I describe below, to the extent NSP becomes unable to construct coal fire facilities in the future, natural gas consumption will increase even further – potentially quite rapidly.

Q Why does this create cause for concern?

A Because gas prices are significantly higher and more uncertain than competing fuels' prices, an increased reliance on natural gas will expose NSP customers to significantly greater price volatility. That is, to the extent NSP is consuming large amounts of expensive natural gas, the costs will be passed through directly to NSP's customers. If unexpected disruptions in natural gas supplies, lower-than-expected imports of Liquefied Natural Gas ("LNG"), reductions in natural gas imports from Canada, severe natural gas price spikes or changes in environmental regulatory policy increase use of natural gas to generate electricity nationwide occur, customers will be directly exposed to these costs as they are incurred. In addition, if NSP's increased consumption puts pressure on Minnesota's natural gas delivery infrastructure, further cost increases could occur.

Q **Does Xcel analyze the potential impacts of natural gas price volatility on the State?**

A No, remarkably, even though natural gas price volatility already has had a significant impact on energy users in NSP's service territory, and is one of the factors Xcel cites to support construction of its proposed coal gasification project in Colorado, Xcel ignores this issue entirely in its filing in this docket.

Notably, Xcel never addresses in any way the potential secondary impacts of its increased use of natural gas on residential and commercial users of natural gas and on other power generators in the State.

Further, Xcel obscures the potential cost burden on NSP's customers by presenting the Commission only with an evaluation of the cost of its proposed resource plan under one gas plan. While I was not allowed to view the gas forecasts by NSP, I was informed by Excelsior who did view the data that NSP used a market based forecast for a short period of time, and then reverted to forecasted gas prices from PIRA. They communicated to us that this analysis ignored the clear potential for significant price spikes in future years. The Commission should not allow this to occur. Instead, Xcel should be required to evaluate the potential consequences of its resource planning decisions (both past and prospective) under a range of different scenarios regarding possible future natural gas prices, as discussed further below.

Q **What else is troublesome about the Engelking analysis of system costs?**

A Xcel's analysis does not reflect any apparent recognition by the Company of the urgent need to minimize its utilization of natural gas during the next decade. It is precisely during this period, however, when NSP's exposure to natural gas price spikes is potentially the most severe. Rather than attempting to develop a well-thought out plan to minimize dependence upon natural gas, however, Xcel simply assumes, as part of a paper planning exercise, that NSP can construct a coal fired plant by 2015 – without specifically committing the Company to build such a plant or even initiating a serious, good faith effort to develop such a plant.

This failure to develop an effective plan for minimizing utilization of natural gas, especially during the period between 2011 and 2020, could have a major adverse impact on economic growth in the State, and potentially on NSP's financial health. And in addition, realistically it may be many years before NSP is able to add conventional pulverized coal-fired capacity to its system – if such capacity is ever added.

Q What do you mean when you question the addition of a coal plant in 2015?

A In the Engelking Direct Testimony, Xcel proposes adding new baseload coal-fired capacity to the NSP system in 2015 – i.e., just over eight years from now. There is no evidence in the record, however, to suggest that NSP has initiated any serious efforts to put itself in a position to build such a plant. While there is discussion in Xcel's testimony, for example, of possibly building an additional unit at the Sherco site, with other utilities potentially participating in the project, there is no evidence that a detailed site evaluation study has been performed or that has made any progress in attracting partners for such a project. Nor does it appear that any of the required permit applications have been filed, that preparation of permit applications has begun or that detailed cost estimates have been developed, either generically or for construction of a specific plant at a particular site.

Instead, the super-critical pulverized coal-fired plants compared to Mesaba in Xcel's analysis appear to be purely hypothetical paper units that may or may not ever be built. Further, even if NSP ultimately builds its own pulverized coal generation as a substitute for Mesaba, it also is exceedingly unlikely that the first of these units would come on line in 2015.

Q What is your basis for concluding that Xcel's assumed 2015 in-service date for new coal-fired capacity is unrealistic?

A Even under the best of circumstances, eight years would be an ambitious schedule to select a site for a new coal-fired generating unit, negotiate a joint ownership agreement and design, permit and construct a new unit – especially for a project of this size and complexity potentially involving multiple partners, many of whom are likely to be required to obtain regulatory approvals before the project can be financed. Here, however, the clock doesn't even appear to have started to run – i.e., NSP hasn't even started serious efforts to initiate the project. Nor is it clear when (if ever) it intends to do so.

Q Is this the principal basis for questioning whether it is realistic for Xcel to assume that NSP can add a new pulverized coal unit to its system in eight years or less?

A No, not by any means. Even if NSP were to begin serious development efforts before the end of this year (as it would need to do in order to have a realistic hope of bringing a new jointly-owned pulverized coal plant on line early in 2015), opposition to building a conventional coal-fired plant in Minnesota could be intense – in part because a conventional coal-fired plant (unlike Mesaba) would not be readily adaptable to carbon sequestration. This could delay the regulatory approval process for years. Even if the required approvals are ultimately granted, the project could then be tied up in litigation for much of the next decade. Further, over the past year, pressure to take action on global warming clearly has been mounting. Other new environmental initiatives also are clearly possible at any time.

Q Please explain these environmental regulatory risks.

A While no one can predict with certainty what new measures might be considered in the future, over time, the perceived risk of requirements that disfavor construction of conventional pulverized coal-fired plants could increase significantly. This perceived risk might be sufficient to stop any proposed pulverized coal plant dead in its tracks at any point – or at least delay any new project for many years. Indeed, it is possible that the point already has been reached at which NSP and Xcel will never be willing to build another conventional pulverized coal-fired unit in Minnesota – without Xcel's management necessarily even fully recognizing this fact.

Q Why is this a problem for NSP's customers?

A Xcel's management, as I understand it, has not yet squarely faced up to the decision of whether to commit to build a new coal-fired plant in Minnesota – either by 2015 or by some later date; while NSP's resource plan considers possible additions of a series of new super-critical pulverized coal plants, no definitive decision has been made as to whether the Company is willing to build a new conventional coal-fired plant (as contrasted with, for example, a coal gasification project). Further, it would not be surprising if one of the reasons Xcel ultimately decided to propose construction of a coal gasification project in Colorado was to avoid the risks that might be entailed if it built a pulverized coal-fired unit and restrictions on greenhouse gases were then enacted at the State or federal level. If and when a decision is made to add new coal-fired generation in Minnesota, the same conclusion might well be reached here – especially given the potential for opposition by environmental groups to construction of a conventional coal-fired plant in the State and the potential that environmental requirements will continue to tighten over time.

Notably, the mere threat of significant restrictions on emissions of greenhouse gases might be enough to deter NSP from ever building a new pulverized coal plant in the State (or, alternatively, potentially delay the start of construction of such a plant for many years), even if no new restrictions are enacted any time in the next five to ten years. This is especially true since Xcel's Chairman, Richard Kelly, has publicly stated that Xcel is not willing to proceed with construction of new generation on an "at risk" basis. It is unclear, however, whether the Minnesota Commission would be willing to fully insulate NSP, in advance of legislation, from the potential adverse impacts of legislation pertaining to global warming or other environmental legislation that has not yet been drafted (much less signed into law) – or that it could lawfully do so, even if it were so inclined. Thus, at least at this point, the hypothetical pulverized coal unit to which Xcel compares Mesaba consists entirely of "paper" megawatts, which Xcel has not specifically committed to build – and which may not ever see life, beyond the testimony filed in this proceeding.

In addition, environmental control standards evolve over time. It is possible that, by the time NSP files a permit application for a new pulverized coal-fired plant (assuming such an application is ultimately filed), the U.S. Environmental Protection Agency and/or other parties will take the position that the "Best Available Control Technology" ("BACT") requirement applicable to such a plant should be defined in a way that effectively would require NSP to build an IGCC project, rather than a pulverized coal-fired plant. If so, it is entirely possible that disputes over the appropriate definition of BACT could delay the issuance of a new permit for several years – and potentially result in NSP eventually building a project similar to Mesaba, but at a much later date.

Q Why is it important for the Commission to realistically assess the likely feasibility and timing of the addition of pulverized coal-fired units on NSP's system?

A It is significant because Xcel effectively is asking the Commission to compare the potential costs and benefits of Mesaba to a hypothetical strawman that, as a practical matter, even under a "best case" scenario, has virtually no chance of being built by 2015 – if it is built at all. As a result, it does not provide a realistic point of comparison to Mesaba. Further, Xcel has not proposed that it bear any of the risks associated with it failing to add new baseload coal-fired capacity by 2015 or with that capacity proving to be far more costly than Xcel assumes. Instead, under its plan, those risks would be borne entirely by NSP's customers.

Finally, as discussed further below, however, these risks potentially could cost NSP's customers billions of dollars – and potentially seriously impair the economic health of the State. The stakes are too high, therefore, for NSP continue dealing in hypothetical, paper-planning exercises that keep shifting every time a new filing has to be made before the Commission, and aren't backed by concrete steps to implement proposed plans.

Q How does this compare with the Excelsior proposal?

A It does not. Excelsior has offered a specific, concrete plan, to build a specific unit with specific performance characteristics at a particular site. This option should be compared with the most likely, realistic alternative coal scenarios for resource additions on NSP's system determining whether IGCC is or is likely to be a least cost resource.

Q Are you surprised that Xcel's evaluation of Mesaba is so deeply flawed?

A Not necessarily. It is of course disappointing that Xcel's evaluation of the resource alternatives available to NSP's system would reflect such fundamental errors –

especially since the stakes for NSP and its customers are so high. To at least a significant degree, however, the flaws in Xcel's assessment stem from more deep-seated issues and problems, which are not unique to Xcel.

Q Please explain.

A Certainly. Fundamentally, the flaws in Xcel's assessment reflect two much deeper issues. First, sound resource planning has become considerably more difficult than it was just five to ten years ago. The range of uncertainty that planners should be taking into account in their decision-making has increased dramatically. The natural gas market, for example – which in the 1990's generally was relatively stable – has undergone far-reaching changes, both on the supply side and the demand side (as discussed further below). Supply and demand – which generally had not fluctuated significantly during the 1990's – began to shift significantly, with major new sources of demand and sudden, steep declines in existing sources of supply. These shifts, if anything, are likely to accelerate in future years.

These changes have led to extraordinary price volatility – price volatility which, if anything, could increase dramatically in future years. Not all of the analysts who cover the industry, however, fully grasp these changes – or have the training or tools needed to properly understand a rapidly changing market. As a result, price forecasters whose forecasts have been reliable in the past have issued price forecasts that (predictably) have proven to be far off the mark. Similarly, if anything, the uncertainties created by emerging environmental issues – particularly global warming – are even greater. At this point, it remains uncertain whether new restrictions will be adopted or, if so, what form they will take or when they will become effective.

The potential clearly exists, however, for sweeping new restrictions, with far reaching implications for how NSP and other electric utilities operate their systems, at some point during the useful life of generating assets expected to remain in service for at least thirty to forty years. This poses difficult new challenges, which the industry has seldom previously been required to face and for which there is no readily-available template. It should not necessarily be surprising, therefore, if many companies initially stumble in attempting to grapple with a daunting challenge of this nature.

Q Is this quantum leap in uncertainty and accelerated rate of change in technology and the fuel markets the only major factor complicating utility resource planning?

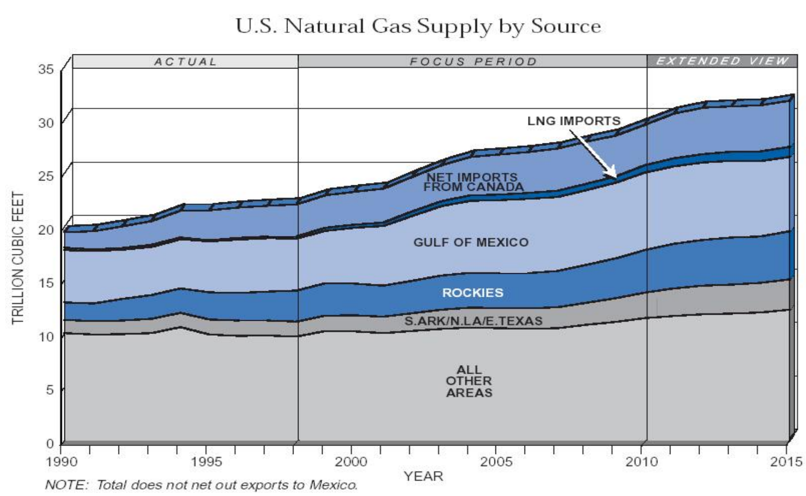
A No, it is not. At the same time that the challenge faced by planners has become more difficult, the experienced resources devoted to the planning process are often declining, both nationally and at the company level. All the ingredients are present, therefore, for a blow-up: the decisions to be made are more challenging, and less knowledge and experience often is being brought to bear to resolve these issues. Not surprisingly, therefore, serious mistakes are often made.

Q Can you provide an example?

A Certainly. Perhaps the most striking example is the failure at the national level to better anticipate the steep increase in natural gas prices that has occurred over the past several years – or to better understand the extent of the risk of continued high prices in future years. This failure already has resulted in more than $150 billion in higher-than-expected costs for natural gas and electricity. By any standard, it reflects a severe breakdown in the process of utility resource planning. Yet, the reasons these cost increases occurred, and the implications for utility resource planning, are not yet fully understood – as Xcel's own actions on behalf of NSP amply demonstrate.

Just four years ago, for example, the U.S. Department of Energy's Energy Information Administration ("EIA") was confidently predicting that the wellhead price of natural gas would indefinitely remain in the high $2.00 to low 3.00/MMBtu range in real terms. *See* Annual Energy Outlook 2002, Table 92. Analyses conducted for the Secretary of Energy concluded that the supplies available to the U.S. market from the U.S. and western Canada could be increased by almost 50% between 2000 and 2015 with at most only a modest price increases. *See* Figure 1.

<u>Figure 1</u>



Source: National Petroleum Council, Meeting the Challenges of the Nation's Growing Natural Gas Demand (Dec. 1999).

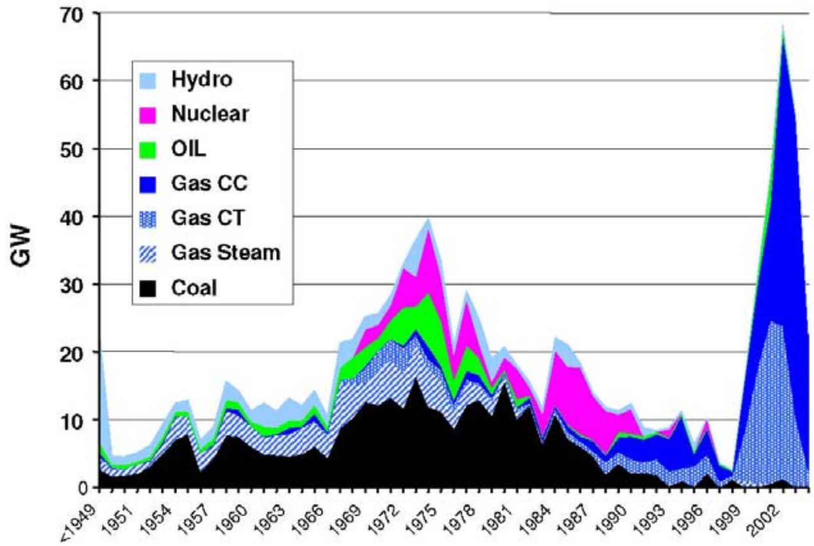
Price forecasts by leading industry price forecasting firms were generally consistent with these predictions.

Q Did utilities and regulators rely on these forecasts?

A Yes, they did – with tragic consequences. After December, 1999, when the National Petroleum Council ("NPC") issued an important Study (prepared jointly with the Staff of EIA), claiming that adequate gas supplies could be obtained from the U.S. and Canadian sources south of the Arctic Circle to meet growing U.S. power demand, the power industry undertook an unprecedented construction program, building more than

225,000 MW of new generation – at a cost of more than $100 billion. In planning this new generation, most generators accepted the joint EIA/NPC finding that adequate supplies of natural gas would be available to meet growing U.S. needs. As a result, more than 98% of generation constructed during this time period was gas-fired. *See* Figure 2.

<u>Figure 2</u>



Source: U.S. Energy Information Administration

Q **Has this proven to be a wise decision?**

A No, it has not. Instead, it undoubtedly will go down as one of the worst failures of energy supply planning and regulatory policy in U.S. history – leading to literally trillions of dollars in potentially avoidable costs.

Q **Please explain.**

A The effect of the decision to build this gas-fired generation, rather than a more diverse generating mix, has been to fundamentally change the generating mix in the U.S., at least for the course of the next decade – increasing the percentage of gas-fired generation from approximately 25% of total U.S. generation (much of which consisted of peaking units, used for only limited time periods) to more than 40% of total U.S generation. As a result, at this point, gas-fired generation is now the marginal source of generation in virtually every Region of the country for an increasing number of hours every year. Further, the increase in power sector consumption of natural gas in summer months has been particularly steep – to the point that, this past July, power sector consumption of natural gas exceeded 1 Trillion Cubic Feet (i.e., approaching 5% of total U.S. supply for the year, for all uses of natural gas in the U.S. economy) in just thirty-one days!

Q Has the North American natural gas industry been able to supply this increase in power sector demand for natural gas?

A No, despite a huge ramp-up in drilling of new wells, and expenditure of record amounts of capital on new development, it has not even come close to being able to meet this increased demand for natural gas. Contrary to the earlier EIA and NPC projections, U.S. production peaked in 2001 – and (despite record U.S. prices) has since *fallen* by more than 1 Trillion Cubic Feet/year (i.e., by more than 5%). Further, while damage due to hurricanes contributed to lower-than-expected production during the past two years, even if no hurricane-related damage had occurred, production *still* would be *far below* 2001 levels.

Q Is this a short term problem?

A No, it is not. It is a chronic, structural issue – which creates an urgent need to minimize future dependence upon natural gas as a fuel to generate electricity, in order to avoid exposing customers to potentially devastating cost increases.

Q Should Xcel be more aware of the magnitude of this problem?

A Yes, it should be. Less than forty-eight months after the National Petroleum Council issued its 1999 Report, at the request of the Secretary of Energy, it completed a new, more comprehensive study of likely North American natural gas supply, which superseded its December, 1999 Report. This Study, completed in September of 2003, reflects the results of a detailed, ground-up basin-by-basin study of every major natural gas producing Region in North America and is perhaps the most thorough examination ever undertaken of potential future natural gas supply in North America.

Q What did this study conclude?

A The 2003 Study concluded that the results of the Council's own 1999 Study were no longer valid. Instead, more careful inquiry had demonstrated that, even with significantly higher prices, it was no longer realistic to expect *any* significant increase in production from "traditional North American sources of supply" (which the Council defined as any source of supply south of the Arctic Circle) at any point in the foreseeable future.

Based upon this assessment, the Council reduced its estimate of likely North American supplies in 2010 by 6 Trillion Cubic Feet, and reduced its estimate of likely supplies in 2015 by 9 Trillion Cubic Feet.

Q Are these significant reductions?

A Yes, they are huge. By way of comparison, for example, in Btu equivalent terms, 6 Trillion Cubic Feet is one and one-half times current U.S. oil imports from the Middle East.

In effect, therefore, the Council's Report concluded that there was a hole in expected U.S. energy supplies equivalent to losing all of our current oil supplies from the Middle East in another four years!

Q Why have estimates of expected future production fallen sharply even though prices are soaring?

A While many factors are at work, fundamentally, most major fields in the U.S. and Canada are aging. The days of peak production are long gone. Further, production from existing wells typically declines significantly every year. Just to maintain total U.S. production at constant levels, therefore, the E&P industry at this point must drill a sufficient number of new wells to replace approximately 32% of the previous year's production from existing wells.

Even a decade ago this would have been a daunting task. At this point, however, the oil and gas industry has been using increasingly sophisticated seismic technology effectively for many years to find and develop the most attractive pockets of natural gas and has developed increasingly effective extraction techniques that allow it to rapidly drain most new wells.

As a result, in many fields, therefore, relatively few attractive prospects remain to be developed. Just to replace lost production from existing wells, therefore, every year the industry must drill a larger-and-larger number of increasingly smaller wells (the so-called "treadmill effect"). Drilling a sufficient number of new wells to *expand* total production becomes an almost impossible task.

Q Have the Council's production forecasts proven to be accurate?

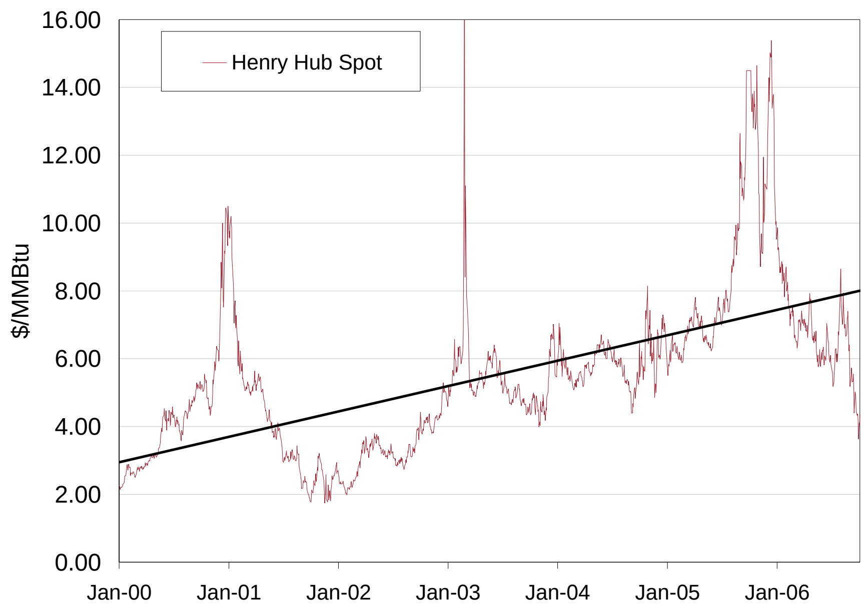
A No, they have not been. While the Council's prediction that production would be far-lower-than expected has proven to be directionally correct, at least so far, its revised estimates have still proven to be too optimistic.

During the three years since its 2003 Study was issued, the price of natural gas has been far higher than it expected, and far more new wells have been drilled. During this same period, however, production has fallen even more rapidly than it expected, with a particularly rapid decline in the size of new wells.

Q How have shortfalls in North American production affected the price of natural gas?

A Not surprisingly, as power sector demand for natural gas has begun to rapidly increase at the same time that U.S. production has been flat or declining, prices have risen dramatically. *See* Figure 3:

<u>Figure 3</u>



Not all of these price increases, of course, are due to structural changes in the market. Hurricanes also played a significant role, particularly for a brief period in the fall of 2004 and again in the fall of 2005, as did very hot weather during the last two summers.

Over the past four years, however, structural changes in the market have resulted in at least $300 billion in unanticipated costs for natural gas and electricity nationally which cannot reasonably be attributed to production losses due to hurricanes. In addition, numerous U.S. manufacturers have been forced to permanently exit the U.S. market.

Further, since the spring of 2003, the net impact of deviations from climatologically normal has been to *reduce* demand for natural gas significantly, compared to the level that might be expected if weather conditions during each successive twelve-month period had matched long-term climatological norms. If weather last winter had matched long-term norms, natural gas prices might well be at an all-time high as this testimony is being filed.

Q Have the most severe natural gas price spikes already occurred?

A No, almost certainly not. The price spikes that have occurred to date could prove to be just the "tip of the iceberg." It is important to keep in mind three factors:

1. <u>As the expected increases in natural gas consumption on NSP's system illustrate, over the next seven to ten years, power sector consumption of natural gas is likely to rapidly expand in every Region of the Country</u>.

While power sector consumption of natural gas has increased rapidly in recent years, many companies are just beginning to "grow into" their new gas-fired units. While many coal-fired plants are being discussed (including NSP's), few are ready to break ground or at an advanced stage in the planning and permitting process. As a result, only a small amount of new coal-fired capacity is expected to come on line anywhere in the U.S. any time between now and 2015. Even then, the number of new coal-fired additions is still very much in doubt.

For at least the next seven to nine years, therefore – and in all likelihood longer – a high percentage of all of the incremental load growth in the U.S. will need to be met through increased use of existing gas-fired capacity.

This virtually guarantees significant increases in power sector demand for natural gas every year on a weather-normalized basis – potentially on the order of at least 400 to 500 Bcf per year, for the better part of a decade (i.e., a total increase in demand of 2.8 to 5.0 Tcf).

2. <u>There is now a consensus within the oil & gas industry that the additional supplies required to meet this increased demand cannot be obtained from traditional North American sources of supply.</u>

At the same time, however, there is now a consensus within the industry that little if any of this increased demand can be met by increased production from U.S. or Canadian sources south of the Arctic Circle. Thus, at the same time that demand is certain to increase dramatically, North American supply is likely at best to be stagnant – creating the raw ingredients for a potential explosion in prices during the course of the next decade.

3. <u>Finally, when price spikes occur, they could be far more severe than in the past.</u>

Over the past four years, a high percentage of the most price sensitive users of natural gas already have been driven from the market. At the same time, the composition of the market is changing rapidly. Due to tighter Clean Air Act restrictions (particularly on NO_x), fuel switching options have diminished radically (removing one of the principal safety valves that has limited natural gas price spikes in the past). Further, as a result of several rounds of high prices, almost every industrial user who was likely to exit the market at prices in the $8.00 to 10.00/MMBtu range or lower already has left the market (e.g., fertilizer manufacturers or methanol producers along the Gulf Coast who have permanently shut their doors). In the future, therefore, when supplies tighten – as they almost inevitably will – steep further price increases may be required to drive additional users out of the market and free up additional supplies of natural gas for use by electric generators.

In the past, CityGate prices of $30.00/MMBtu or above occasionally have been required to balance the market in Chicago, New York or Boston, and prices as high as $55.00 have been required in San Francisco, at least for brief periods. Over the next few years, it would not be surprising if similar price levels from time-to-time are required to achieve market equilibrium in other markets as well.

Q What lessons should be drawn from the failure to anticipate the steep increase in natural gas prices that has occurred over the past four years?

A The failure to anticipate the dramatic increase in natural gas prices that has occurred over the past four years already has caused several hundred billion dollars in unexpected costs, and saddled the industry with over $100 billion in “steel in the ground” that is likely to be far more expensive to operate than expected at the time the decision was made to build these plants. This suggests a high level of caution, in determining what assumptions to make regarding future natural gas prices as part of any planning analysis.

At least three specific lessons can be drawn from the experience of the past four years.

Q Please describe the first of these lessons.

A Certainly. One clear lesson is that any forecast of future natural gas prices is inherently subject to a high degree of uncertainty. In the past four years, even the most “optimistic” price forecasters (i.e., those predicting the smallest price increases) generally have almost doubled their price forecasts – even though projections of future demand have now declined.

There is no guarantee, however, that even these revised forecasts will prove to be accurate. Instead, the errors in previous forecasts demonstrate fairly clearly that the "state of the art" in developing natural gas price forecasts leaves much to be desired in terms of accuracy or reliability. Almost every forecast starts, either directly or indirectly, with EIA's assessment of supply and demand. EIA, however, only has a tiny staff devoted to developing its natural gas price forecasts. Further, as the experience of the past several years demonstrates, the assumptions used in developing supply estimates are inherently imprecise. Even projections two or three years out have proven to be far off the mark. Projections further out in time are inherently even more suspect – subject to a much higher degree of error.

This suggests that any natural gas price forecast must be assumed to potentially be subject to a high degree of error. These errors, however, are not necessarily symmetrical.

Q Why is the risk of error not necessarily symmetrical?

A In years in which prices are lower-than-expected, producers are likely to cut back on production, limiting the decline in prices. When supplies are tight, however, there is no necessary upper limit on price increases – especially as more and more natural gas is used for essential uses, such as electric generation, where the cost may be spread over many users and there may be no ready substitute in some Regions.

Q Is there a second lesson?

A Yes, in NSP's case in particular, there is special reason for caution, due to its experience relating to the Metropolitan Emission Reduction Project ("MERP").

Q What is this lesson?

A I want to make clear that, in raising this issue, I'm not addressing the question of whether the MERP project should have been undertaken – regarding which I have no view.

At the time the MERP project was being considered by the Commission, however, in the fall of 2003, Chairman Koppendrayer asked me to appear before the Commission to discuss the reasonableness of the natural gas price assumptions Xcel had used in the analysis it had presented to the Commission regarding the project. I indicated at the time that, in my judgment, the prices Xcel assumed were far too low, and had the effect of severely underestimating the likely cost to NSP and its customers of undertaking the project. In my presentation, I explained many of the reasons why natural gas prices were likely to increase significantly in future years.

Since subsequent events have strongly vindicated that analysis, I would have assumed that Xcel would have considered this analysis seriously.

Q During the past three years, has Xcel re-evaluated its assumptions regarding natural gas prices?

A At least from the record in this proceeding, I see little evidence that it has. Since the assumptions Xcel used previously proved to be far off the mark, and potentially will prove very costly to ratepayers, I would have assumed that, following the MERP proceeding, Xcel would have thoroughly re-examined the basis for its natural gas price forecasts and tried to determine why the forecasts it had used previously proved to be so inaccurate.

Every indication, however, is that Xcel simply is proceeding on a "business as usual" basis, without trying to understand the basis for its previous mistakes and instead simply using an updated version of the same basic forecasts that proved to be so far off the mark in the past.

Q Is there a third lesson?

A Yes, there is. If Xcel had more carefully examined the reasons why past forecasts were inaccurate, it would have quickly concluded that there is an even greater risk of further price increases in future years.

Q Why is the risk of additional price increases in future years so great?

A Fundamentally, price forecasts developed during the 2000-2002 time frame proved to be far too low because they: (i) greatly overestimated likely future production from U.S. and Canadian fields; and (ii) underestimated likely future increases in power sector consumption of natural gas.

The risk of overestimating future supplies is even greater now, however, than it was four years ago. Further, estimates of future power sector consumption of natural gas still are almost certainly too low.

Q Why is the potential for major shortfalls in supply even greater now than it was four years ago?

A It is important to remember that, four years ago, almost all of U.S. supply still was expected to come from existing supply basins in the U.S. and Canada. Forecasts were attempting to predict future production, therefore, from fields in their own backyard. Further, except for deepwater projects in the Gulf, most of this production was expected to be obtained from on-shore drilling, using existing technologies. The fact that, even relatively near-term, most estimates proved to be far off the mark should prove to be sobering, to say the least.

Q Do the same risks still apply to future estimates of North American production?

A Yes, they do. The pattern continues to be that the decline rate for U.S. and Canadian fields is increasingly more rapidly than expected. In addition, several other factors, discussed later in my testimony, could lead to larger-than-expected shortfalls in production. The most significant risks, however, relate to expected “new” sources of supply.

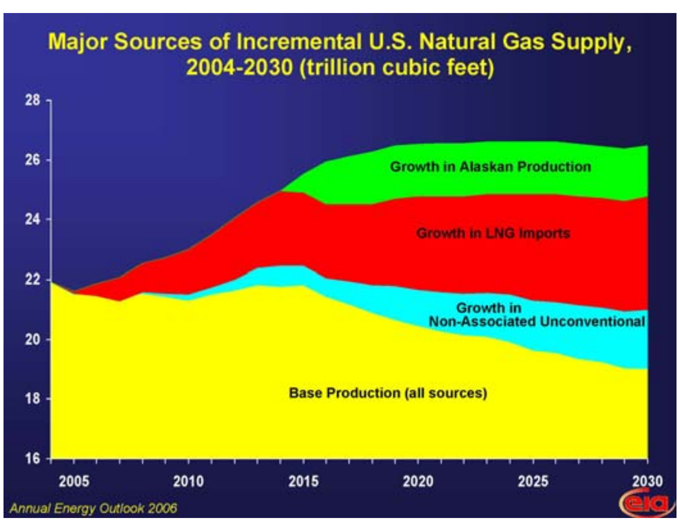
Q Please comment.

As noted earlier, to the best of my knowledge, no one in the industry any longer believes that natural gas requirements of the U.S. economy can be met from traditional sources of supply. Instead, the incremental natural gas requirements of the U.S. market are expected to be met primarily from two sources of supply:

- The proposed Alaskan natural gas pipeline; and
- A huge increase in U.S. imports of LNG.

In EIA’s most recent forecast, for example, these two sources of supply account for all but a small percentage of future growth in U.S. supply. *See* Figure 4.

<u>Figure 4</u>



Each of these sources of supply, however, involves uncertainties and risks of a nature never previously faced in the U.S. market.

Q What are some of these risks and uncertainties?

A EIA's most recent projections, for example, assume that the proposed Alaskan natural gas pipeline will be completed by 2015 and that production will quickly be ramped up to more than 5 Bcf/day – accounting for more than 7% of total U.S. supply.

Q Is this projection likely to be met?

A No, at this point it is virtually certain that it will not. While the project hopefully will still move forward, the status of the project is still in doubt, and it is possible that the pipeline never will be built. Further, even if it is, completion could be delayed by many years.

Q Would further delay in undertaking or completing this project potentially affect the price of natural gas in the U.S. during the middle part of the next decade?

A Yes, it almost certainly would. Even in a "best case" scenario, in which the project ultimately is completed, there is a high risk that, at the earliest, it will not come on line until late in the next decade. This is likely to create another major hole in expected U.S. supply, leading to significant further increases in the price of natural gas in the U.S. market.

Q Has Xcel taken this risk into account in its analysis?

A There is no indication that it has. In fact, it almost certainly has not – since it is using a natural gas price forecast that pre-dates some of the recent forecasts for the Alaskan project.

Q Is there also a risk that imports of LNG will fall short of EIA's projected levels?

A Yes, there is a very high risk that imports of LNG will fall far short of assumed levels and that the cost of whatever LNG is brought into the U.S. market often will be far higher than was expected just a year or two ago.

Q Why are LNG imports likely to fall far short of expected levels?

A It is important to recognize that EIA's projections are based on the assumption that massive amounts of LNG can be imported into the U.S., largely from projects that are not yet built -- and in most instances have not yet even begun construction. Further, these projects generally have at least a four to seven year lead time and take several billion dollars to build.

A long list of factors could cause LNG imports to fall shorts of the levels EIA assumes, including:

- Delays in starting or completing new projects;
- Fewer new projects than expected being started;
- Production outages at existing facilities;
- Shipping delays;
- Strikes;
- U.S. purchasers being outbid by purchasers from other countries for the output of existing projects; and
- Production declines at existing fields.

These risk factors create uncertainties regarding future LNG import levels that are on a completely different scale than the uncertainties associated with increasing drilling rates at existing U.S. fields.

Q Is there already evidence that future U.S. LNG import levels are likely to fall far short of EIA's sections?

A Yes, there is. The points just raised are not by any means just theoretical possibilities. Instead, in the past twelve months, there is substantial evidence that *every one* of these factors will work to reduce the amount of LNG brought into the U.S. market. Notably, EIA already has significantly reduced its estimates of likely future LNG import levels during the last twelve months. There is a substantial likelihood, however, that these estimates will be reduced further in subsequent years – possibly quite dramatically.

Q Does the experience of the past twelve months also highlight some of the uncertainties associated with future LNG import levels?

A Yes, it does. While the U.S. has a critical need for additional natural gas supplies, and LNG can make a significant contribution to meeting this need, the experience of the past twelve months also demonstrates some of the uncertainties associated with future supplies.

During this period, the U.S. experienced the highest natural gas prices in U.S. history. On a year-over-year basis, however, even when U.S. prices were at their peak, LNG imports often declined.

Q In the future, are LNG cargoes likely to continue to be diverted to other, higher-priced markets, reducing import levels into the U.S.?

A Yes. In the future, an increasing number of cargoes are likely to be sold on a spot-market basis. The market-clearing price for these cargoes is likely to frequently be set by whatever purchaser any place in the world is willing to pay the highest price for those cargoes at any particular point in time. In addition, in part due to the long lead time required to plan and construct new liquefaction projects, the amount of LNG available to serve the global market is likely to frequently lag global demand. Because the U.S. also is more distant than most other purchases from most suppliers, the U.S. will also be at a competitive disadvantage in competing for many of these cargoes.

As a result, U.S. purchasers are likely to frequently be outbid for available supplies. Even when supplies flow into the U.S. market, the price often is likely to be much higher than may have been anticipated just two or three years ago.

Q How could this potentially affect natural gas prices in the U.S. market?

A The potential for LNG imports to fall below expected levels and/or for LNG imports to be significantly more expensive than expected could have a major impact on the price of natural gas in the U.S. market during the period beginning in 2012 (the potential start date for Mesaba 1).

As indicated previously, during the next decade, increased LNG imports are expected to be the primary incremental source of supply for the U.S. market. This is a fundamental shift in the natural gas supply strategy, requiring the U.S. to rely on sources of supply that have not yet been built, in a global market that still is at an early stage in its development. The potential for supplies to fall short of expected levels, or for prices to be higher-than-expected, should be readily apparent to anyone who carefully assesses the risks associated with this market.

By early in the next decade, however, LNG imports are likely to play an increasingly important role in setting the market clearing price in the U.S. market, especially during periods of peak demand. Further, the U.S. natural gas market is exquisitely sensitive to even modest shortfalls in supply.

If LNG imports fall short of expected levels, therefore, or prices are higher than expected, the impact on prices in the U.S. market could be immediate and severe.

Further, since the North American market generally operates on an integrated basis, there is likely to be an immediate, direct impact on the price NSP pays for natural gas, irrespective of the source for that gas.

Q Did Xcel consider these risks in evaluating system costs?

No, there is no evidence that it did so in its filing. Instead, Xcel appears to have ignored these risks entirely, even though the potential implications for its customers are huge.

Q Please summarize your conclusions on how Xcel has analyzed the Mesaba PPA's impact.

A I find that the Engelking Direct Testimony presents an incomplete analysis. It is based on flawed assumptions and is of no probative value for this proceeding. An appropriate system analysis is one that relies on a more appropriate set of assumptions that test the sensitivity of the analysis to changes in underlying assumptions. As I explain below, such an analysis leads to the conclusion that entering into the Mesaba PPA is likely to provide major benefits to NSP's customers in Minnesota.

IV. A MORE ROBUST APPROACH TO THE SYSTEM IMPACT ANALYSES

I have examined Xcel's approach to system impact analysis and found it to be deficient and of no probative value to an inquiry into system costs. Below is my detailed analysis.

A. REQUIRED METHODOLOGY

Q What approach do you believe is an appropriate methodology for evaluating these risks?

A At a minimum, Xcel should conduct a serious of sensitivity analyses that test the results of its system impact analyses to variations in underlying critical assumptions.

Below I explain the importance of sensitizing the analysis by showing how the absence of such evaluations will put NSP's customers in the position of bearing the risk of potential extreme rate increases in the future.

Q What specific assumptions should be evaluated?

A Xcel should have started its analysis by using realistic assumptions in its Reference Case analysis for load growth, capital costs of different generation alternatives, fuel prices and all of the other inputs into its application of the Strategist model – which it has failed to do. Since has not yet made a firm commitment to build a new pulverized coal-fired unit, for purposes of establishing a Reference Case, it also should have established a Reference Case in which no new coal-fired capacity is added to its system, and compared that reference case to various alternatives – including a case in which it enters into the proposed Mesaba PPA and a case in which, if it ultimately decides to go forward with a new pulverized coal unit, that unit is added at a date that NSP is confident is achievable, even though it apparently has not yet even begun the process of finalizing the selection of a site, deciding whether to seek partners in such a project (and, if so, negotiating a joint ownership agreement with those partners), choosing a technology vendor or finalizing major design specifications for the unit.

After establishing these cases, at a minimum, it then should have evaluated the potential consequences to its customers of pursuing these alternative resource plans under various scenarios that might adversely affect NSP's customers. At a minimum, the scenarios to be evaluated should include:

- The potential consequences of higher natural gas prices;

- Potential new environmental requirements (i.e., requirements to reduce emissions of Greenhouse Gases, new restrictions on mercury, SO_2, $PM_{2.5}$, etc.);
- Other major risk contingencies (i.e., higher-than-expected load growth, hotter-than-normal summers, extended shutdowns at one or more nuclear plants, early retirements or higher-than-expected forced outage rates at major coal-fired plants, etc.); and
- Scenarios that combine one or more of the above.

The importance of category (4) – i.e., scenarios that combine multiple risk factors – deserves to be emphasized.

As we've seen over the past three and one-half years, even during a period in which environmental requirements have generally not changed significantly, natural gas prices have been vulnerable to extreme price spikes. As discussed below, if anything, this "standalone" vulnerability to price spikes is likely to increase in future years – since much of the price sensitive demand for natural gas has now been driven from the market, and an increasing portion of our natural gas supply (from LNG) is vulnerable to supply interruptions or to U.S. purchasers being outbid by purchasers from other countries (risks that generally don't exist, at least in an analogous way, with current sources of supply).

If significant new restrictions are adopted on emissions of greenhouse gases, however (such as the restrictions recently signed into law by Governor Schwarzenegger in California, which post-date NSP's filing), or other major new environmental restrictions are adopted that result in the retirement of a significant number of existing coal-fired plants (as could occur as a result of restrictions on $PM_{2.5}$, for example), all bets are off. Power sector demand for natural gas would be likely to escalate sharply –

potentially in a relatively short time period, with no easy ways to satisfy this sudden increase in demand.

In these entirely plausible scenarios, natural gas prices could quickly escalate to unprecedented levels – and potentially remain at highly elevated levels for many years.

Further, this risk of sharply elevated prices exists even in years in which conditions are otherwise normal. In years in which summer weather is hotter-than-normal (elevating summer air conditioning demand), or winters colder-than-normal, or nuclear or hydro availability nationally not as robust as it has been during the past year, the increase in natural gas prices could be significantly higher – potentially pushing the price of natural gas to levels never previously seen in the U.S. market.

It is precisely this type of scenario, of course, that potentially has the most brutal impact on customers – since electricity is an essential commodity, and NSP is likely to be required to fully serve load, even if its marginal cost of production becomes very high. It is not difficult to imagine scenarios in which, by the middle of the next decade, costs to NSP's customers in Minnesota could increase by $1 billion or more in a single year as a result of such a scenario occurring.

Any sound planning exercise, therefore, should carefully evaluate the extent to which different planning alternatives mitigate potential risks of this nature. NSP's filing, however, provides no indication that it has conducted such an analysis.

Q How does this analysis bear on a proper evaluation of the Mesaba PPA?

A As discussed further below, the goal of any planning exercise, in a world of increased risk and uncertainty, should be to select a robust resource plan, which protects customers under a broad range of possible scenarios.

It is difficult to see how a plan that satisfies this criterion can be properly developed without conducting an analysis along these lines.

Q What would such an analysis show here?

A If Xcel had conducted such an analysis, it would have quickly recognized that the potential exposure of NSP's customers to natural gas price spikes, especially if it continues adding gas-fired capacity to its system and/or new environmental requirements are enacted – could be huge. Once this exposure became apparent, I would have expected it to develop a well-thought out action plan to reduce the exposure of NSP's customers to future natural gas price volatility. While this is one of the stated objectives of Xcel's plan to build a coal gasification project in Colorado, there is no indication that Xcel has given any similar consideration to how to protect customers in Minnesota against this risk.

Q Did ICF conduct an analysis for Excelsior that used more realistic assumptions and examined multiple scenarios?

A Yes, it did.

Q What did this analysis show?

A It shows quite clearly that IGCC from Mesaba is likely to provide major cost benefits to NSP's customers in Minnesota – potentially saving NSP's customers several billion in net present value terms when looking at direct costs under some scenarios, as well as providing numerous other benefits that are relevant in assessing the costs of different alternatives.

Q Did ICF perform certain modeling runs for Excelsior, to evaluate the potential impact of the Mesaba PPA on system costs?

A Yes, it did.

Q For the Excelsior Mesaba reference case did FTI review the capital cost assumptions for the cost of building new coal or gas fired generation?

Yes, FTI reviewed the capital costs of new unit type options considered by Xcel and found them to be low in today's market .In terms of utilizing the most current market data for the upper mid-west, current capital cost estimates from the IRP processes related to the Big Stone project in South Dakota were used in the ICF analysis:

- New Pulverized Coal – Instead of the Xcel assumption of approximately $1748/kW (2005$), new pulverized coal plants were assumed to cost $2,769/kW (2005$). This cost is consistent with costs currently reported for an actual unit, Big Stone II, currently under construction in South Dakota less transmission (Big Stone II Applicants' Supplemental Pre-filed Direct Testimony, Exhibit 33-H) and was derived by using the total capital costs, less transmission from Exhibit 33H, adjusting upward to include AFUDC to get to a figure of $3,056/kW for a plant that is coming on line in 2011. With an assumed construction midpoint of 2009, these costs were then de escalated back to 2005 using an estimated inflation rate of 2.5%.
- New Natural Gas Combined Cycles - Instead of the Xcel assumption of $690/kW, new combined cycle plants were assumed to cost $1148/kW (2005$) based on Southern Minnesota Municipal Power's 2006 Integrated Resource Plan. Southern Minnesota Municipal Power , a partner in Big Stone II , utilized a figure of $1177/kW (2006$) and this number was de escalated to 2005$ using the 2.5% inflation estimate.

- New Natural Gas Simple Cycles (Combustion Turbines) - Instead of the Xcel assumption of $574/kW, new combustion turbine plants were assumed to cost 15% above this or $660/kW. The 15% was added to account for recent increases in commodity and EPC contracting costs. This assumption is conservative when compared to actual increases realized in recent years.

Q How is the remainder of this Section organized?

A The remainder of this section addresses specific issues that should be evaluated as part of any sound system analysis regarding:

- Natural gas prices;
- Potential changes in environmental requirements; and
- Other major risk factors that could adversely affect NSP's customers in Minnesota.

It also will discuss the specific assumptions ICF was asked to use regarding natural gas prices in the modeling runs it performed on behalf of Excelsior.

B. NEED TO PROPERLY ASSESS THE POTENTIAL CONSEQUENCES OF NATURAL GAS PRICE SPIKES

Q Given the potential consequences of higher natural gas prices to NSP's customers, how would you have expected Xcel to take into account potential exposure to natural gas price volatility for purposes of resource planning on its system?

A First, I would have expected Xcel to attempt to consider developing a new methodology for developing natural gas price forecasts. The problems with the methodology it has used in the past are hardly minor in nature or narrow in scope. Instead, the methodology it has used historically failed to predict one of the most massive dislocations that has ever occurred in the natural gas market. Thus, it hardly can be considered to provide a reliable basis for future planning. Second, once NSP develops a new methodology for developing gas price forecasts, I then recommend examining a series of scenarios, examining the potential consequences to its customers of a series of different gas price levels, involving gas prices spiking to different levels.

Q In your judgment, would it be consistent with sound planning principles to examine only one gas price scenario?

A No, it would not be. In my judgment, it would be imprudent *per se* to examine only one possible natural gas price scenario, and reflect a profound misunderstanding of the nature of the U.S. natural gas market – which inherently involves a high level of uncertainty and unpredictability, and vulnerability to periodic extreme price spikes that can result in hundreds of millions of dollars in increased costs to NSP's customers in Minnesota in a relatively short time period.

Instead, given the natural gas price shocks that already have occurred in the past three and one-half years, and the rapid increases in natural gas dependence that are occurring on NSP's system, in evaluating different resource alternatives, I would have expected Xcel to examine the potential outcome of natural gas prices remaining at recent levels on a long-term basis a range of different assumptions regarding possible future price levels – including the potential impact of periodic price spikes in specific years.

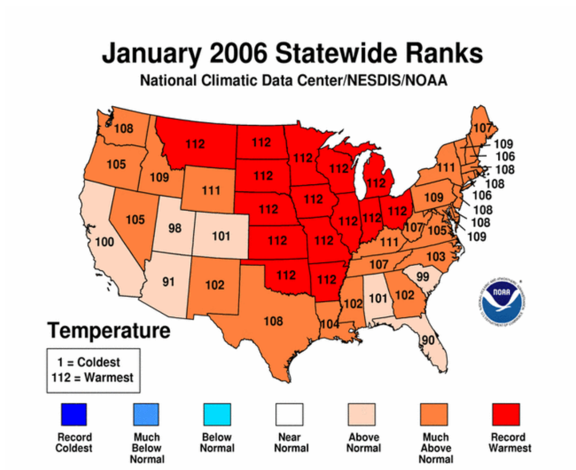
Q What specific range of price assumptions would you recommend examining?

A One possible conservative approach might be to start by looking at recent price levels.

Q **Why do you consider this approach to be conservative?**

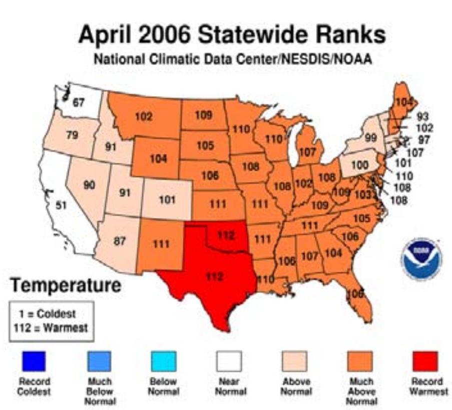
A Temperatures this past winter were among the mildest in recent years. The average temperature in January in particular – normally the heart of the winter heating season – was the mildest in the 112 years for which the National Weather Service maintains records. *See* Figure 5:

<u>Figure 5</u>



As a result, the normal winter-time draw down of working gas in storage didn't occur. Temperatures in April also were the mildest in the 112 years for which the National Weather Service has record, reducing space heating demand in the spring. *See* Figure 6.

<u>Figure 6</u>



The effect of this very mild winter weather has been to temporarily cause prices to plummet (more than canceling out the impact of last year's hurricanes or the hotter-than-normal weather that occurred this summer).

Q Is it possible that the very mild weather this winter was due to the impact of global warming?

A No, at least not according to the meteorologists to whom I have spoken. Notably, there was no shortage of very frigid air in the northern hemisphere this winter. This past December also was reasonably cold. In December, however, a formation developed in the Arctic called an Aleutian Trough. This formation ultimately developed in a way that pulled this very frigid area down into Japan, China, Siberia and Western Europe. All of these areas and even Alaska had one of the coldest winters in the past forty years. If this formation has split slightly differently, this same frigid air might have been pulled into North America. If this had occurred, we might have had the coldest winter since 1960 and natural gas prices might be at an all-time high. Instead, however, this same pattern that pulled very frigid air into Asia and Europe allowed milder air from the tropics to move up into the U.S. – resulting in the warmest conditions in North America in 112 years, and pushing down natural gas price this year.

Q What has the twelve-month strip for natural gas been priced at recently?

A At the time of NSP's most recent filing, for example, despite extremely mild weather last winter (which has tended to drive down prices), the twelve-month strip for 2007 had been averaging approximately $7.67/MMBtu (value as of 8/31/06 of 2007 futures contracts traded on the New York Mercantile Exchange, per Bloomberg's). This is $1.81/MMBtu *below* the average price level for the twelve-month strip for 2007 during the past year, which at of August 31, 2006 was $9.48/MMBtu.

During the previous twelve months, price in the Day Ahead market at Henry Hub had averaged \$8.57/MMBtu. Further, prices had exceeded \$14.00/MMBtu on ten separate days, during three different months (i.e., September, October and December), peaking at \$15.39/MMBtu on December 13th.

I would have expected Xcel, therefore, to at least look at scenarios in which future prices matched each of these possible price levels (e.g., \$7.67, 8.57, 9.48 and 14.00/MMBtu), since prices are virtually certain to reach levels at least this high during the period covered by the Mesaba PPA. Instead, at least for purposes of its filing with the Commission, it appears to have used a price well below the lowest price at Henry Hub on any date during the twelve-month period ended August 31, 2006 (again I cannot be certain given Xcel's ensuring that I could not review its natural gas price forecasts).

Q Don't some price forecasts still predict that natural gas prices are likely to decline in future years?

A Yes, they do. I do not believe these forecasts, however, are appropriate to use as a basis for planning decisions.

Q Why do you believe that it is inappropriate to use these forecasts as a basis for planning decisions?

A For at least three major reasons:

1. <u>Many of these forecasters (including EIA) now have a proven, multi-year track of producing consistently inaccurate forecasts</u>.

Because they have staked out a position that has proven to be badly mistaken, however, they may perceive that they have a vested interest in trying to vindicate their earlier views.

Unless they are able to offer persuasive reasons, therefore, as to: (i) why their earlier forecasts proved to be inaccurate for reasons that could not reasonably have anticipated; or, alternatively, (ii) how they have changed their methodology to prevent similar errors in the future, it is unreasonable to base important decisions on price forecasts from forecasts whose predictions in recent years consistently have proven to be far off the mark. Instead, the errors in these predictions strongly suggest that there are major flaws in the methodology by which these predictions are being developed.

2. <u>Even these forecasters generally acknowledge that, while in their view prices are likely to "typically" range at a certain level in future years, periodic price spikes are virtually certain to occur – and could be quite extreme.</u>

To analyze the cost of difference resource plans based solely on the "average" price forecast by these price forecasters (which is not even intended to represent a true "average") is to misapply these forecasts, in a manner that could cause extreme harm to NSP and its customers in Minnesota.

As NSP should be well aware, natural gas prices have spiked to up to three to four times "normal" levels when supplies have tightened in the past, due to colder-than-normal winter, pipeline disruptions, or any of a variety of other factors. Price spikes of approximately this magnitude occurred during the past twelve months in Europe due to cold weather this past winter and supply curtailments from Russia (which accounted in part for the drop in LNG imports into the U.S., even last December, when U.S. prices were at an all-time high).

Periodic price spikes almost certainly will occur in the future – and could become more frequent and more severe, as the U.S. becomes increasingly dependent upon LNG imports (which, unlike North American production, could swing sharply from month to month) and the vulnerability of the U.S. market to swings in weather-driven demand (especially in winter and summer months) continues to increase.

This increased exposure to natural gas price volatility already has required NSP to request extraordinary increases under its fuel adjustment clause, at a time when its dependence upon gas-fired generation still is relatively modest.

In coming years, however, NSP's exposure to the potential impacts of natural gas price spikes will increase dramatically – even if both Mesaba units are built at the earliest possible date and it ultimately contracts for all of the output of both units.

Depending upon the severity of the price spike, the difference between having the Mesaba units on line, and continuing to rely on natural gas, could easily amount to half a billion dollars or more *in a single year!*

Over the first ten years in which the plant operates, billions of dollars could be at stake. It is unconscionable, therefore, for NSP not even to look at scenarios at which natural gas prices spike to levels higher than those considered in the testimony it has filed to date with the Commission.

3. <u>Finally, and perhaps most significantly, prices significantly below the recent level of the twelve-month strip for 2007 (i.e., $7.67/MMBtu in $2007) in all likelihood are simply not sustainable in the U.S. market on a long-term basis.</u>

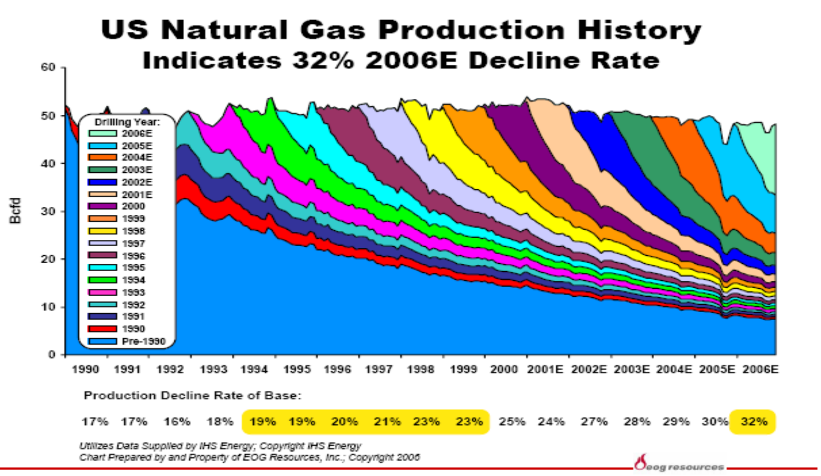
As a result, they do not provide a reasonable basis for making planning decisions on a long-term basis.

Q Please explain the basis for your conclusion that prices significantly below $7.67/MMBtu in $2007 in all likelihood are not sustainable in the U.S. market on a long-term basis.

A Certainly. U.S. developers are finding it more and more difficult to identify prospects that are suitable for development on a long-term basis. In addition, finding and development costs are continuing to increase at a rapid rate. While the spot market price may occasionally fall to significantly lower levels for brief periods of time, therefore (as has occurred this fall), the twelve-month strip, beginning a few months out, is unlikely to fall to significantly lower levels for any extended time period. This is because, if the twelve-month strip, looking out beyond the next 90 to 120 days, were to begin to start falling significantly, developers would be likely to begin quickly cutting back on drilling rates – preferring to wait to develop their remaining prospects at a time when the price environment offered more favorable returns.

Since the U.S. decline rate already has reached 32%, and is likely to continue increasing in future years, even a modest cut-back in drilling rates would be sufficient to cause supplies to quickly tighten. *See* Figure 7.

<u>Figure 7</u>



Developers are unlikely to ramp-up drilling again, however, until they are reasonably well convinced that prices have returned to attractive levels.

Except for relatively brief periods, therefore, \$7.67/MMBtu could ultimately prove to be close to a long-term floor for the twelve-month strip. The long-term *average*, however, could easily be twice as high, and prices almost certainly will periodically spike to *at least* the \$14.00/MMBtu level one or more times during the next decade – and quite possibly much higher, with potentially devastating consequences for NSP and its customers.

At a bare minimum, therefore, Xcel should be required to at least *examine* the potential impact of price spikes that reach these levels in its resource planning processes, and should take this potential into account in determining whether to turn its back on units that have the potential to significantly reduce its dependence upon natural gas in future years.

Q Are the factors that have been enumerated above the only considerations that are relevant in evaluating the potential importance of Mesaba as a means of reducing NSP's dependence upon natural gas?

A No, not by any means. Instead, despite the harm that higher natural gas prices already have caused to the U.S. and Minnesota economy, in my judgment, the severity of future price and supply risks is still not well understood.

It has been three years, for example, since the National Petroleum Council completed its 2003 Study. Since that time, much has changed – much in a way that is not helpful. As noted earlier, for example, North American production has declined even more rapidly than the NPC expected. Further, the NPC Study assumed completion of the Alaskan natural gas pipeline by 2013, early completion of the MacKenzie Valley Pipeline in Canada, and prompt elimination of restriction on offshore drilling for oil and gas – none of which has occurred.

Further, the 2003 Study assumed much slower growth in demand for electricity than is occurring. Moreover – and most significantly – the NPC also assumed that oil prices would *decline* to $20 per barrel.

This was a key assumption in its findings – which called for a massive *re-conversion* of gas-fired powerplants and gas-fired industrial boilers to oil, and construction of a large fleet of new oil-fired powerplants, to relieve mounting pressure on the natural gas market.

These findings – made just three years ago – of course no longer appear realistic, and highlight the potential risks of assuming that our energy needs can be easily met. No one has gone back, however, and attempted to reevaluate the conclusions of the 2003 in light of these changes in the world oil market – which also bear directly on the likely future price and availability of LNG (which the Council explicitly assumed would be priced at a premium to the expected price of oil).

Q Are the NPC's mistaken assumptions your primary cause for concern?

A No, they are not. Fundamentally, despite the far reaching importance of the price and supply of natural gas to the U.S. economy – and its growing importance to Minnesota in particular – since the 2003 NPC Study was completed, to the best of my knowledge, no one has attempted to undertake a comparable (or, if possible, even more thorough) assessment of likely future supply and demand. Instead, to a large degree, at both the federal and state level, most analyzes are relying upon the annual forecasts of supply and demand prepared by EIA.

While EIA does the best that it can, however, with limited resources, after many years of budget cutting at the federal level, it is forced to rely on a very small staff to perform a critical task. It also lacks the budget resources to use outside consultants extensively or to immediately correct known deficiencies in the modeling and data collection systems it uses to develop its estimates. Not surprisingly, therefore, its estimates have been far off in the past and almost certainly are far off now.

Q In your judgment, is there a significant risk that U.S. natural gas prices often will be far higher than EIA currently projects?

A Yes, I believe that, on average that is nearly certain to be the case, for many years to come. Many of the reasons for this conclusion are discussed earlier in my testimony. In addition, however, in my judgment, numerous other factors contribute to this risk – many of which have not yet been adequately assessed by EIA and are often not adequately considered in other analyzes.

Q Could you identify some of the factors that contribute to this risk of higher prices?

A Yes. Without attempting to provide an exhaustive list, even before considering the potential impact of environmental requirements that have not yet-been adopted (discussed further below), at least twelve specific factors provide cause for particular concern:

1. <u>The likelihood that power sector consumption of natural gas in the U.S in many years will greatly exceed currently-forecast levels</u>. EIA's published forecasts for future power sector consumption of natural gas in its Annual Energy Outlooks have consistently underestimated power sector consumption of natural gas – typically by a large margin. (This year's consumption, for example, is likely to significantly exceed levels currently projected for 2012.) While a portion of this variance is due to very hot weather this summer, hotter-than-normal weather may occur again in future years. Further, EIA's model appears to significantly understate demand in this key sector of the economy, even on a weather-normalized basis. This in turn appears to be

causing many private forecasters to seriously underestimate future U.S. demand.

2. The impact of recently enacted CO_2 reduction requirements in California. The recently enacted California global warming legislation could seriously exacerbate this problem, even if no other State enacts similar requirements. CO_2 reduction requirements are virtually certain to result in significant increases in consumption of natural gas, especially in the first five to ten years after the reduction requirements go into effect, when the options for reducing emissions may be fairly limited. (The California limits are scheduled to go into effect in 2011.) Since these requirements were just adopted, they have not yet been factored into EIA's forecasts (which as a matter of policy assume no changes in existing laws).

3. The impact of higher oil prices on consumption of natural gas. The increase in oil prices that has occurred over the past two and one-half years is likely to have a huge impact on future U.S. natural gas consumption, as well as future U.S. supplies – neither component of which has yet been fully factored into EIA's forecasts. At least three major elements are involved:

    a. Greater natural gas use at power plants and industrial boilers/conversion back from oil to natural gas. Higher oil prices have had a major impact on the natural gas market throughout the past twelve months. They effectively set the market clearing price last December, when prices at Henry Hub peaked at just over \$15.00/MMBtu. Since then, after mild weather reduced winter demand for natural gas, natural gas has been heavily substituted for residual fuel oil in the limited circumstances where it is still feasible to do so. This has increased natural gas consumption this year. EIA has not yet had an opportunity, however, to assess potential long-term implications for demand.

b. Explosive growth of the U.S. bio-fuels industry. A second, potentially explosive source of increased demand for natural gas – not yet factored into EIA's forecasts and ignored by many analysts – is the potentially explosive growth of the U.S. bio-fuels industry. This industry is extremely energy intensive, and has started to grow at an exponential rate as a result of the passage of the Energy Policy Act of 2005 (which provided major new incentives for bio-fuels production) and the phase-out of MTBE (which is being replaced primarily by ethanol in most regions of the country).

During the remainder of this decade, increased demand for natural gas by the bio-fuels industry is likely to be the single fastest growing segment of U.S. industrial demand.

Many analysts, however, are not yet taking this growth into account in their forecasts.

c. Explosive growth of Canadian demand for natural gas – and corresponding sharp decline in Canadian natural gas exports to the U.S. By far the most important factor affecting the U.S. natural gas market, however, is the explosive growth that is expected to occur in the Canadian oil sands industry – which, like the bio-fuels industry, is extremely energy intensive.

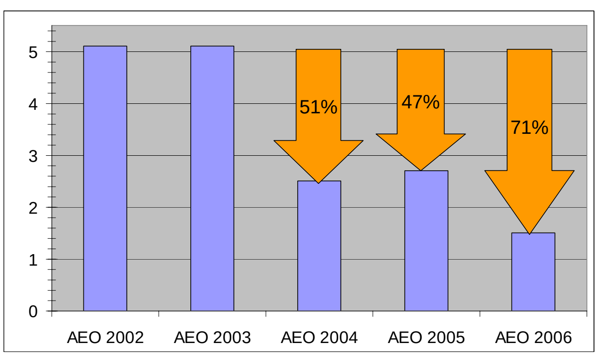
It is important to remember that, just two and one-half years ago, projected future oil prices were only about half of current levels. In this scenario, oil sands development was expected to increase dramatically – but on a phased basis.

Since then, planned development has exploded. This inevitably will have a major impact on the amounts of Canadian gas available to the U.S. market.

Largely as a result of expected growth in Canadian demand related to the oil sands projects, EIA already has dramatically reduced its estimates of future Canadian imports. *See* Figure 8.

<u>Figure 8</u>

Forecasted Canadian Natural Gas Imports, 2020
Trillion Cubic Feet



Even this estimate, however, is likely to prove to be too optimistic (i.e., to understate the likely decline in Canadian imports).

The U.S. currently imports a total of approximately 9.1 Bcf/day from Canada, which accounts for a little over 15% of current U.S. supplies.

Under some plausible scenarios, however, imports from Canada could decline to near zero by 2020. No other single factor has the potential to have a more disruptive impact on the U.S. market or to lead to steeper price increases.

To the best of my knowledge, however, the extent of this risk has not yet been thoroughly evaluated by either the U.S. or Canadian government or by any private party.

4. The impact of the planned shut-down of all of the coal-fired generation in Ontario. Ontario has committed to shut down all of its coal-fired generation (more than 3,000 MW of capacity) by the end of this decade. This also will significantly impact supply and demand of natural gas in the U.S. market, both by increasing use of natural gas to generate electricity in Canada (further reducing the amount of natural gas available for export) and increased power demand in the U.S. (in order to enable U.S. generators to export more power to Canada). This factor also does not yet appear to have been properly factored into many assessments of future supply and demand.

5. Failure to achieve expected penetration levels of DSM and renewables. Both in Minnesota, and nationally, projections of future electricity demand and future utilization of gas-fired units increasingly assume very aggressive goals for DSM, wind and other sources of renewable energy.

These aggressive goals deserve to be strongly supported; the urgency of the looming natural gas crisis demands that we do all that we can to reduce total demand and to develop non-fossil-fuel sources of energy.

The track record suggests, however, that these aggressive goals often may not be met.

It is important to recognize, therefore, that since gas-fired generation increasingly is both the marginal source of supply for electric generation, both in the Upper Midwest Region and nationally, that even a modest shortfall in achieving these goals can lead to a huge increase in the use of natural gas to generate electricity. It is essential that this potential impact be explicitly modeled, using a range of assumed “success levels” for DSM and wind – which Xcel has not done, and which EIA has not factored into its Reference Case forecast for power sector demand for natural gas.

This can lead to a huge understatement of likely future demand for natural gas.

6. <u>Potential that a significant number of older coal-fired plants will be retired or converted to natural gas</u>. Especially at a national level, a surprisingly large percentage (i.e., more than 20%) of the nation’s fleet of coal-fired units consists of relatively old (i.e., often more than sixty years old), relatively small units and/or coal-fired units that are continuing to operate in or near major urban areas. Except for the MERP units, however, relatively few units in this category that have not been burning exclusively natural gas for many years have been shut down or converted to natural gas anywhere in the at any time in the past decade. Further, only a relatively small number are assumed to be retired in EIA’s future projections of demand for natural gas.

As these units continue to age, with concerns regarding environmental issues remaining high, it is possible that an increasing number of these units either will be retired or re-powered and converted to natural gas – as is occurring with the MERP units. Over the next decade, this could be a powerful factor leading to further increases in power sector demand for natural gas.

7. <u>Potential for on-shore production in many U.S. fields to rapidly decline</u>. The potential for major increases in demand for natural gas, however, which have not yet been factored into most price forecasts, is only the “tip of the iceberg,” in terms of reasons for fearing that natural gas prices may rapidly escalate in future years. Instead, there is even greater reason concern regarding the

stability of future U.S. supplies. The likelihood of a sharp fall-off of imports from Canada already has been discussed. There is a substantial risk, however, that U.S. production also will fall far short of EIA's current projections – both for on-shore and off-shore wells.

With respect to on-shore wells, perhaps the single greatest concern is the potential – perhaps even the likelihood – that one or more major U.S. fields will soon enter a period of rapid and irreversible decline.

The high prices of the past three and one-half years have spurred a tremendous ramp-up in drilling of new wells. Only a fraction of this drilling, however, has been in newly developed fields; most has been in existing fields.

While this intensive drilling has helped to avoid a more precipitous decline in total U.S. production – at least on a short-term basis – in many fields, the effect inevitably is to accelerate the point at which these fields inevitable will enter into steep and irreversible decline. While it usually is impossible to tell precisely when this point is likely to be reached in particular fields, some industry experts believe that, in several major fields it is likely to occur before the end of this decade – much as has been occurring in the Near Shelf Region in the Gulf since the late '90s.

If and when this occurs, total U.S. production is likely to enter into another period of precipitous decline – just as has occurred over the past several years, as a result of the steep fall-off in production in the Near Shelf Region in the Gulf.

This in turn could easily lead to another sudden upward jump in prices, much as has occurred during the past thirty-six to forty-eight months.

8. <u>The potential that future production in the Gulf of Mexico will fall far short of expected levels</u>. Another major potential concern is the potential – perhaps

even the likelihood – that growth in deepwater production in the Gulf will fall far short of expected levels. While numerous factors give cause for concern, two recent developments stand out:

Over the past twelve to eighteen months, due in part to higher oil prices, a significant number of deepwater rigs have been pulled out of the Gulf and moved to the Middle East or other locations around the world. This appears to be a long-term shift. Unless it is reversed, however, it may inevitably mean much lower-than-expected future natural gas production in the Gulf (which, along with the Rockies, up until now has been expected to be a major area for future growth).

Further, while very recent, a potentially even more significant development (while potentially good news for the oil market) is the apparent successfully drilling of a test well in the Jack Field in the Gulf of Mexico. If this project leads to commercial development, it could be the most significant U.S. oil find in twenty-five years. Because of the depth of the deposits, however, unprecedented amounts of drilling will be required to develop this resource. Further, this drilling will be exclusively for oil. (Because of the location of the field, 170 miles from shore, no pipeline delivery system will be built; even if natural gas were to be discovered, therefore, there would be no way to bring it to shore.)

This potentially has huge implications for the development of natural gas supplies over the next ten to fifteen years, since it may result in very little new natural gas development in the Gulf for prolonged periods of time.

9. <u>The potential that, even if the Alaskan natural gas pipeline is built, completion of the pipeline ultimately will be delayed by many years</u>. The critical role the Alaskan pipeline is expected to play in future U.S. natural gas supply, the risk

that it may never be built and the potential for extended delays even if construction moves forward all were discussed briefly earlier in my testimony.

For present purposes, the point to be emphasized is the likelihood that, even if the project ultimately moves forward, it will not be completed until long after the completion date currently assumed by EIA (i.e., commercial operation early in 2015).

The proposed Alaskan pipeline is one of the most ambitious projects ever proposed – i.e., 3,000 miles in length, running through both the U.S. and Canada, requiring approximately 54 million manhours to construct, using 5 to 6 million tons of steel, with an expected cost of approximately $20 billion.

At this point, however, it is at the conceptual stage only. At least according to the information published by the project sponsors, it appears that preliminary design work has not yet begun. Permit applications have not yet been developed – much less filed. The process of collecting field data also has not yet started.

According to the timeline published by the sponsors, therefore, even if every conceivable open issue necessary to move forward with the project could be resolved immediately, and there were no glitches in the permitting process at the State, Federal, local or Provincial level in either the U.S. or Canada, the earliest that permits required for construction could be issued is 2011.

Experience with large, controversial projects, however, strongly suggests the potential for numerous delays along the way.

This has huge implications for the potential value of the Mesaba project to Minnesota, particularly during the period between 2015 and the early part of the following decade.

If the Alaskan pipeline ultimately proceeds forward, for example, but completion eventually is delayed until 2020 (which is not by any means an implausible scenario), effectively reducing expected U.S. supply of natural gas by 5 Bcf/day in the intervening years (i.e., more than the combined impacted of Ivan, Katrina and Rita on U.S. production, for a much longer period of time), it would not necessarily be surprising if the effect were to increase the price of natural gas by $5.00 to 7.00/MMBtu for all or most of the period between 2015 to 2020.

Yet, there is no apparent indication that Xcel took this possibility into account in conducting its resource planning or system analysis.

10. The likelihood of fierce competition for available supplies of LNG. While alluded to briefly before, over the past year it also has become increasingly apparent that during the next decade, there is likely to be fierce competition for available supplies of LNG. Several recent developments bear mention:

Russia's aggressive attitude last winter and again more recently with respect to the Sakhalin Island project has sent shock waves through Europe, causing several major European governments to make major commitments to reduce their dependence upon Russia as a source of supply. Especially during the period between 2010 and 2020, however, this is likely to be accomplished primarily by stepping up significantly imports of LNG. Further, since we already are past the window for starting projects that might come on line early in the next decade, much of this increased supply inevitably will need to come in head-to-head competition with the U.S. countries, in what increasingly is likely increasingly to become a zero sum game for supplies that fall well short of total global demand.

Current producers – particularly Indonesia – also have reported disturbing declines in production, reducing expected future supplies. Other projects (such as in Australia) have been much slower-than-expected to get off the ground.

Russia's aggressive posture regarding Sakhalin Island also could have major repercussions regarding future natural gas development in Russia, reducing the flow of capital and technology into the country – and therefore increasing pressure on European countries to find alternative sources of supply.

There also has been a huge explosion of demand from India – which just two years ago was largely ignored in many projections of likely supply and demand.

The consistent pattern, therefore, appears to be one of lower-than-expected supplies and significantly greater demand —demand that could intensify dramatically, if concerns regarding global warming continue to increase.

11. <u>The lack of evidence that a second major tranche of LNG projects will be built out rapidly</u>. Current global supply projections assume that, after the round of projects announced starting in 2003 and 2004, there will be a continuing flow of new liquefaction projects. The first round of projects, however, has proved to be far more expensive than expected, and in the interim there has been a major shift in focus to development of gas-to-liquids projects. In the past year, there have been very few signs that a next generation of new projects is likely to move forward soon.

Without these projects, however, there is no "Plan B" for meeting the needs of the U.S. and global markets in the later part of the next decade – or beyond.

12. <u>High likelihood that LNG typically will be priced against oil in global markets</u>. Finally, within the expert community, there is a growing consensus

that LNG is likely to generally be priced on an oil equivalent basis. By the middle part of the next decade, this almost certainly will mean prices well above the current level of the twelve-month strip for 2007. Xcel itself predicts a link between world oil and gas prices in its November 2006 Base Load Process Study.

Q What conclusions do these factors suggest?

A During the past seven years, EIA's natural gas price forecasts have proven to be utterly unreliable as a basis for planning. If anything, however, the reasons to be cautious in considering these forecasts now are more compelling than at any time during this seven year period.

Q Please describe the natural gas price assumptions you believe Xcel should analyze in order to conduct meaningful system analysis.

A At a minimum, even when evaluating scenarios in which there no new environmental requirements are adopted, NSP should have evaluated a range of different scenarios, in which natural gas prices in any one year might range anywhere between \$7.67/MMBtu in \$2007 (i.e., the lowest month-end value for the next-year twelve-month strip at any time during the past twelve months) and \$15.39/MMBtu in \$2005 (the highest daily weighted average price in the Day Ahead market at Henry Hub during the past twelve months (but not necessarily the peak price level in future years).

Q What specific price levels did you ask ICF to use for purposes of its modeling runs?

A To err on the side of being conservative, I asked ICF to perform its runs using an assumed natural gas price of \$7.67/MMBtu in \$2007 (i.e., the potential future floor price, prior to considering potential price spikes, and value that is likely to *least* favor Mesaba). I also asked ICF to perform a sensitivity analysis that examines the potential costs to

NSP's customers if Xcel fails to add new coal-fired generation and natural gas prices reach $14.00/MMBtu (a price which is still well below the peak price levels I believe we are likely to see in the next decade).

Q What did the results of this analysis show?

A This analysis shows that, even in a low gas-cost scenario, the difference in costs between Mesaba and NSP's proposed resource plan are negligible. In a more realistic scenario, Mesaba is likely to produce huge benefits for customers. Therefore, a plan that includes Mesaba is the most robust protection available for NSP ratepayers.

C. SYSTEM ANALYSIS NEEDS TO TAKE INTO ACCOUNT THE POTENTIAL FOR MAJOR CHANGES IN ENVIRONMENTAL REQUIREMENTS IN FUTURE YEARS

Q Is this the only major flaw in NSP's analysis of system impacts?

A No, not by any means. A second, equally egregious flaw in NSP's assessment is that NSP conducts its entire analysis using *status quo* assumptions during the entire period covered by its analysis – i.e., assuming, in effect, that there will be no new environmental requirements that might be relevant to its choice of generating assets with potential useful lives measured in decades.

Q In your judgment, is this a reasonable assumption?

A No, it is not. There is a great deal of uncertainty, of course, regarding *what* new environmental requirements might be enacted, the *specific form* they might take and *when* they might go into effect. A wide range of outcomes are clearly plausible.

The likelihood that the *status quo* will continue indefinitely, however, with no new requirements being enacted – which is effectively very close to what NSP assumes – is not very high.

Q Given the uncertainty that exists, how should Xcel have assessed the potential impact of future changes in environmental requirements in order to conduct sound system analysis?

A Just as with fuel prices, Xcel should have examined a range of potential scenarios, and evaluated the potential impact on system costs of different resource plans under each of these scenarios.

Q What are some of the potential changes in environmental requirements Xcel should assess in dept in conducting a systems analysis?

A Xcel should have carefully assessed, for example, the potential impact on its system needs of new mercury requirements, new $PM_{2.5}$ requirements, requirements for additional reductions in SO_2 emissions and potential changes in the definition of BACT.

By far the most important issue for Xcel to consider, however, is the potential that it might be required, pursuant to either federal or state law – or potentially even as the result of a voluntary commitment by the Company's management – to make major reductions in its emissions of Greenhouse Gases, potentially as soon as the early part of the next decade.

Q Why should Xcel have carefully evaluated the potential impact of requirements that it achieve major reductions in its emissions of greenhouse gases?

A The global warming issue is extremely controversial, and I am not being presented as a witness on *whether* restrictions on emissions of Greenhouse Gases should be imposed.

Pressure to take action on Global Warming is mounting, however. Further, the underlying science suggests that, if reductions in emissions are required, they could be severe.

In my judgment, therefore, perhaps the single most important issue that should concern the senior executives of any major utility – comparable to the uncertainties associated with natural gas – is the potential for stiff new global requirements.

It is difficult for me to see how a utility can prudently evaluate planning options in its system impact efforts without carefully evaluating the potential impact of such requirements.

Q Didn't Xcel include a carbon-adder as part of its analysis?

A Yes, it did. The carbon-adder it used in its analysis, however, doesn't even begin to capture the potential costs that might be incurred by its customers if NSP is required to comply with major CO_2 reduction requirements, and has not taken this potential into account in its planning. Making the extremely simplistic assumption of a tax, without building a full scenario – including dramatically higher natural gas price assumptions – that is consistent with any form of carbon limit, does not yield useful information.

Q What specific scenarios should NSP have evaluated if it wanted to present meaningful system impact analysis?

A One good starting point might be the scenarios that the Commission already has specifically directed NSP to evaluate as part of its resource planning process.

Q Please describe those scenarios.

A The Commission has specifically directed NSP to evaluate four possible reduction targets:

- 7% below 1990 levels;
- 7% below 1999 levels;
- 15% below 1999 levels; and
- 30% below 1999 levels.

Further, the Commission has further directed NSP to examine the potential costs and risks to its system if it is required to meet each of these requirements in 2008, 2015 or 2025.

Q How do these reduction requirement potentially bear upon the choice between Mesaba and other possible expansion plans?

A The potential that NSP might be required to meet reduction requirements of this nature has huge implications for the choice between alternative expansion plans.

If the Mesaba project does not go forward, the most likely alternatives are that: (i) NSP will continue adding a large number of gas-fired generating units to meet its future generating needs; or (ii) alternatively, that at some point (although in all likelihood not nearly as early as 2015) it will seek to add a new pulverized coal plant (as it currently has proposed as a placeholder in its IRP) or seek to add a IGCC plant similar to Mesaba.

If NSP is forced to meet significant CO_2 reduction requirements any time within the next ten to fifteen years, however, and Mesaba is not built, the results could be disastrous for NSP and its customers.

Q What potential adverse consequences could NSP and its customers suffer if Mesaba is not built?

A First, in any scenario in which significant new CO_2 reduction requirements are enacted, gas prices will escalate sharply – in all likelihood to levels never previously seen on a sustained basis in the U.S. market. To the extent NSP has continued to add gas-fired resources, therefore, the potential cost consequences could be staggering – potentially amounting to many billions of dollars.

Second, if NSP has opted to build a pulverized coal-plant, it would be faced with one to two scenarios, either of which could have extreme negative consequences for its customers: either it might still be in a position to cancel construction of its plan coal-fired plant (which might leave it without the ability to add new coal-fired capacity to its system for many years) or it might have no alternative other than to complete construction (which might leave it with a nearly impossible burden it trying to comply with newly-imposed requirements for it to reduce system-wide emissions of CO_2). Either result could become a nightmare that could haunt NSP and its customers for years.

Finally, even if it ultimately had opted to build its own IGCC project in Minnesota, it would have no means of bringing on new coal-fired capacity until several years after the expected completion date for Mesaba. Thus, it would lack a potential low-carbon emitting source of coal-fired generation when the need for such a resource is potentially most acute.

Q Would entering into the Mesaba PPA potentially avoid this dilemma?

A Yes. One of the major potential benefits of Mesaba is that both Mesaba units are adaptable to carbon sequestration. Mesaba offers the potential to provide NSP and its customers, therefore, with up to 1,200 MW of potentially low-carbon emitting source of coal-fired generation at a time when the system may have a critical need for this resource in order to avoid runaway costs for its customers.

This is potentially one of the most compelling benefits of the Mesaba project. NSP has simply erased it from the board by ignoring entirely the obvious potential for major changes in environmental requirements during the live of the Mesaba project.

This oversight is particularly egregious, since the Commission has specifically directed NSP to examine a series of specific carbon reduction scenarios as part of its planning process – a requirement which NSP apparently has simply chosen to ignore for purposes of this proceeding.

Q What steps should be taken to correct this deficiency in Xcel's analysis if it were to be ascribed any weight?

The failures described above point to the complete deficiency of Xcel's system analysis if its goal was to inform the Commission's judgment about the most robust approach to ratepayer protection. While the Mesaba Project is not, by statute, to be subjected to this system analysis in any event, the fact that Xcel's analysis is fundamentally deficient is further reason to dismiss it from consideration. Putting aside the statutory exemption from the requirements of certificate of need, significant deficiencies in Xcel's system modeling would have to be addressed before its system impact analysis could be afforded any weight in any event.

Xcel would first have to correct the modeling deficiencies noted by Mr. Joseph Cavicchi and Ms. Maria Scheller, and then work with the parties until the inputs, assumptions and inconsistencies in Strategist outcomes identified to date are fully understood and capable of being subjected to meaningful consideration by the Commission. Xcel could then be specifically directed to assess the potential impact on system costs of entering into the Mesaba PPA, versus continuing to build gas or building pulverized coal at a realistic future date, under each of the carbon reduction scenarios previously specified by the Commission. Again, all parties would need to have full access to this modeling effort and provided access to key personnel who could explain the approach, inputs and outcomes.

As part of this assessment, the Commission would need to direct Xcel to specifically assess the potential impact of different carbon reduction scenarios, if they were to be applied on a nation-wide basis, on the price of natural gas, and on the feasibility of continuing to constructed new pulverized coal plants.

V. OTHER FACTORS THAT MUST BE TAKEN INTO ACCOUNT IN ANY SOUND PLANNING EXERCISE.

Q Are there also other factors that Xcel failed to properly take into account in its analysis of system costs?

Yes, there are. NSP also failed to properly take into account numerous other factors that can lead to much higher costs – either in specific years, or over extended periods of time or both.

Q Can you provide examples?

A Yes. Examples include: (i) the potential for higher-than-expected load growth; (ii) continued hotter-than-normal summers; (iii) extended shutdowns, poor performance or even early retirement of one or more of NSP's existing nuclear or coal-fired plants; (iv) poor availability of wind resources; (v) unavailability of open-market purchases to meet capacity or energy shortfalls; and/or (vi) inability to achieve NSP's aggressive goals for DSM and/or for addition of renewable energy resources to its systems.

Q Could these factors have a significant impact on system costs?

Yes, these factors potentially could have a huge impact on NSP's costs – that potentially could amount to hundreds of millions of dollars in a single year and billions of dollars over an extended period.

Once again, however, NSP appears to have ignored these impacts entirely in its analysis.

Q In your judgment, is this appropriate?

A No, it is not. One of the major benefits of adding coal-fired capacity to NSP's system at any early date is that it reduces the exposure of NSP's customers to these costs.

These factors are routinely considered in assessing system costs and risks. By excluding these factors from its analysis, NSP has once again significantly understated the potential benefits of the Mesaba plant.

VI. CONCLUSIONS

Q Please summarize your conclusions.

A NSP has presented a flawed analysis of system costs, with no probative value in this proceeding. A properly conducted analysis would have shown that there is an urgent need to proceed forward with both Mesaba units immediately.

Q Does this conclude your rebuttal testimony in this case?

A Yes.