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October 31, 2006

VIA E-MAIL AND U.S. MAIL

The Honorable Steve M. Mihalchick
Administrative Law Judge
Office of Administrative Hearings
100 Washington Square
Suite 1700
Minneapolis, MN 55401-2138

Re: In the Matter of a Petition by Excelsior Energy, Inc. for Approval of a Power Purchase Agreement Under Minn. Stat. § 216B.1694 and Determination of Least Cost Technology and Establishment of a Clean Energy Technology Minimum Under Minn. Stat. § 216B.1693
OAH Docket No. 12-2500-17260-2
MPUC Docket No. E-6472/M-05-1993

Dear Judge Mihalchick:

Attached hereto please find an original and one copy of the Surrebuttal Testimony on behalf of the Minnesota Chamber of Commerce. Also enclosed please find an Affidavit of Service to all parties of record.

Very truly yours,

Richard J. Savelkoul

RZS/clj
Attachments

cc: See Service List.

STPL-Word:90412.1

MINNESOTA CHAMBER
of Commerce
THE VOICE OF BUSINESS

Surrebuttal Testimony of

William Blazar

Before the
Minnesota Public Utilities Commission

In the Matter of the Application of a Petition by Excelsior Energy, Inc. for Approval of a Power Purchase Agreement Under Minn. Stat. § 216B.1694 and Determination of Least Cost Technology and Establishment of a Clean Energy Technology Minimum Under Minn. Stat. § 216B.1693

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October 31, 2006

Table of Contents

I. INTRODUCTION

Q. Please state your name.

A. William Blazar.

Q. Are you the same William Blazar who testified on behalf of MCC in reply testimony in this proceeding?

A. Yes.

Q. What is the purpose of your surrebuttal testimony?

A. I will be providing surrebuttal testimony in response to the rebuttal testimony of James Skurla, Renee J. Sass, Elion Amit, Karen T. Hyde, and John J. Reed in issues of economic development benefits and appropriate terms of the PPA.

II. ANALYSIS

Final PPA

Q. What from the business customers' perspective must the PPA do to be in the public interest?

A. It must deliver reliable and competitively priced baseload electricity to Xcel's system. For guidance on both, we should look to Xcel's most recently approved resource plan, that has been reviewed by the Public Utilities Commission (PUC) and meets all the resource and ratepayers protections requirements of state law. The resource plan identifies resource needs which the proposed project can meet and the PPA should be drafted accordingly. By taking this approach, the proposed project can deliver Xcel's ratepayers (including businesses) reliable, competitively priced electricity while also bringing some economic development of northeastern Minnesota. In approving Xcel's resource plan, the PUC already made a determination regarding the size and timing of Xcel's systems baseload needs. This Excelsior proceeding should determine if all other statutory requirements are met.

I want to stress that a primary consideration should be Xcel's ratepayers and their need for reliable and competitively priced electricity.

Size of PPA

Q. Should Xcel purchase 450-megawatts of baseload energy from Excelsior pursuant to Minn. Stat. § 216B.1694?

A. No, the legislature's intent for this statute was to, upon meeting other statutory requirements, require Xcel to purchase only that power which is necessary for the baseload needs of Xcel's Minnesota ratepayers. According to Xcel's most recent resource plan order (2004), Xcel's needs are far less than 450-megawatts.

Minn. Stat. § 216B.1694 clearly gives the Commission the authority to modify any required purchase pursuant to statute by the amount necessary as to not create waste. The PPA purchases pursuant to Minn. Stat. § 216B.1694 should be modified to only include necessary purchases pursuant to Xcel's most recent resource plan order.

In hearings on October 5, 2006, Excelsior offered an explanation as to why 450-megawatts was selected by the legislature. In essence, Excelsior proposed that it likely was because 450 MW was the amount necessary to fulfill Xcel's Minnesota ratepayers' needs for baseload according to Xcel's then most recent proposed resource plan (2002). (See MCC Exhibit ____ (BB Surrebuttal 1)). I agree with this intent, but baseload needs have changed. Any required purchase under this proceeding should only be for the amount necessary to satisfy Xcel's needs under its current resource plan.

Q. *In determining public interest, would it be in the public's interest for Xcel to purchase more power than is needed to supply Xcel's ratepayers with the baseload energy needed as required by their most recent resource plan?*

A. Certainly not. This would promote waste and unnecessary expenses for Xcel's ratepayers. Xcel does not need any baseload until 2015 and any excess purchases would be resold until that time and beyond. Presumably, at some point Xcel's customer demand would increase to the level proposed by Excelsior, but until then the customers would be paying for more plant, equipment and operating expense then is contemplated by the most recently approved resource plan. This PPA would cost ratepayers in excess of $2 billion, over 22 years. Customers can not afford this. (See MCC Exhibit ___ (BB Surrebuttal 2)).

Q. *In other publications, MCC has maintained Xcel's baseload resources are inadequate, please reconcile that statement with your position in this case.*

A. It is my position that Xcel is currently behind in baseload resources. That will not be the case in 2012 when this PPA would come online.

Q. *Are there things that Excelsior and Xcel could do with respect to this PPA that could make it more beneficial to the state?*

A. Yes, in addition to revising numerous provisions of the PPA to protect Xcel's ratepayer interests, the PPA could be modified to only sell the amount of power that is necessary to fulfill Xcel's baseload needs according to its most recent resource acquisition plan. As discussed above, Xcel will have excess power that will be sold on the market. If Excelsior reduces the power purchased by Xcel and changes the appropriate payment terms, this should result in a reduction of the over two billion dollars of increased costs that is a result of this PPA as it is currently drafted.

Economic Development

Q. *Please respond to reply comments made by James A. Skurla on behalf of Excelsior Energy Inc. regarding the economic development impact of the project.*

A. I want to respond to the updated Research Report that was prepared under Mr. Skurla's direction by the University of Minnesota – Duluth Labovitz School of Business and Economics, Bureau of Business and Economic Research. Both the updated and the original report (2005) are economic multiplier and input/output analysis using a model created by the Minnesota IMPLAN Group, Inc. Basically, this model estimates the impact in both the Arrowhead Region and the state as a whole of the proposed investment. It provides estimates for both the project's construction phase and for a typical operating year.

The most accurate way to understand its estimates is to consider them the static or "gross impact" of the project. They show how dollars spent will flow through the region's and state's economy. They are not adjusted for the other economic effects of the project, most notably the economic impact of any increase in electric rates that result from this project. Factoring in this effect would produce estimates of the project's dynamic or "net impact" on the region and most importantly, the state as a whole. Most importantly because the majority of the rate impact of this proposal will occur in Xcel's service territory which is outside of the area that will benefit most by Excelsior's investment in plant, equipment and operating payroll, i.e. the Arrowhead Region. In summary, the modeling that has been done is "static" and to meet the test of Minn. Stat. § 216B.1694, which requires "economic development benefits to the state," a "dynamic" analysis must be done.

Our state Department of Employment and Economic Development does this for major economic development projects using the REMI (Regional Economic Models, Inc.) model. It is a common tool for projecting the full economic impact of the benefits and costs associated with any major capital investment or policy change.

Let me elaborate on the type of economic impact analysis that is needed. First, I think the economic development benefits from this project should be estimated and compared against the economic benefits that would otherwise occur by virtue of Xcel Energy, Inc., acquiring baseload necessary to fulfill its existing resource plan, i.e. if Xcel was to add more baseload at its Sherburne County facility.

Second, the economic benefits should be measured against the economic costs associated with increasing rates for Xcel's ratepayers (See MCC Exhibit ___ (BB Surrebuttal 3)) beyond what they otherwise need to pay under other baseload acquisition scenarios. As discussed in my rebuttal testimony, there will be a cost to increased rates in the form of less disposable income for individuals who, will in turn, be reducing spending, which will create less revenue for businesses and less sales tax collections for Minnesota, and businesses will have less revenue as well as higher electric bills, which will mean less income, which will increase the cost of doing business in Minnesota and cost Minnesotans jobs and less income tax collections for the state as a result.

Attached as MCC Exhibit ____ (BB Surrebuttal 4) is a copy of a study showing the effects of increasing rates beyond what is necessary for ratepayers, which demonstrates that increasing rates does have a negative impact on economic development. MCC has not performed such a study in Minnesota nor apparently has Excelsior. Absent such analysis and a positive result from it, Excelsior does not meet the statutory burden of demonstrating that there are net positive economic development benefits to the state as a result of this project.

Q. Please respond to Ms. Sass's contention that negative impacts associated with higher prices should not be incorporated into the economic development benefit analysis.

A. I strongly disagree. First of all, I do not think that the PPA as currently drafted will produce baseload electricity that is or is likely to be least cost resource, exhibits attached hereto show the contrary. There is sufficient evidence to demonstrate that the project as currently defined is not least cost, specifically, Xcel's modeling that demonstrates this PPA is over $2 billion more expensive than its next cheapest alternative.

Furthermore, this position is confusing as Excelsior has maintained that they are entitled to the PPA under Minn. Stat. § 216B.1694 despite the costs of the PPA (I disagree with this interpretation). If Excelsior claims, as Ms. Sass does, that economic development does not need to analyze rate impacts because they are the least cost resource, they must prove they are a least cost resource in order to satisfy economic development requirements of

Minn. Stat. § 216B.1694, and thus, price is a factor that is weighed under that statute. If not, the economic development analysis must be redesigned with a dynamic model.

Default/Security

Q. Please discuss concerns with respect to collection of damages in the event of an Excelsior default under a PPA in this proceeding.

A. I am concerned that Excelsior Energy is not adequately capitalized to protect Xcel and its ratepayers in the event of a default by Excelsior.

See Excelsior's response to MCC's Information Request No. 6. (See MCC Exhibit ____ (BB Surrebuttal 5)). Excelsior represents that it will only be capitalized to the extent necessary to meet lender or PPA obligations. The PPA must require additional capitalization or other security to protect ratepayers. Xcel typically includes such provisions in its contracts. See Xcel's response to MCC's Information Request No. 19 (See MCC Exhibit ____ (BB Surrebuttal 6)).

Innovative Energy

Q. How should the Commission ensure that Innovative energy is produced pursuant to statute?

A. Xcel energy entered into PPA's under the biomass statutes, those PPA's required a minimum amount of the output was biomass based, similar provisions should be put into any PPA for IGCC electricity in this proceeding. Mr. Osteraas's rebuttal testimony suggests that the company might agree with and incorporate this concept into a new draft of the PPA. We appreciate that and would like to discuss this suggestion, including how it could also be applied to fuel charges.

PPA Terms

R. *How should the Commission review or modify this PPA if the necessary statutory requirements are met?*

A. As I discussed in my rebuttal testimony, the economic risks should be fairly balanced with respect to what is commonly entered into for ratepayer protections in PPAs. The economic risks as proposed by Excelsior appear to be disproportionately pushed off to ratepayers.

The following issues also need to be addressed: if the plant is more expensive than what similar technology would cost by another provider, only those costs that are reasonable should be recovered; if the plant is scaled larger than is necessary, only those costs for an appropriately scaled facility should be recoverable, or only the proportional costs based on the size of the PPA as a percentage of total costs of the facility; if Excelsior is attempting to recover or sell power that is not generated from "innovative" sources (natural gas), those purchases and the related fuel charges should be limited, similar to statutory limitations of not more than 25% from non-biomass sources that apply to biomass purchases.

Q. *What changes should be made to Excelsior's PPA?*

A. Several parties have provided helpful testimony with respect to specific provisions that could or should be included in a PPA, including Elion Amit of the Minnesota Department of Commerce, and Karen T. Hyde and John J. Reed of Xcel Energy, but ultimately, the majority of these are considerations that should be negotiated and considered in their entirety within the context of a PPA. Making one change may have an unintended effect on other provisions if the PPA in its entirety is not considered.

There are certain provisions that could be ordered in this proceeding and other provisions that could be negotiated, all of which should be addressed and included to some extent in the PPA.

An example of provisions that should be ordered:

1. The PPA should not be for more than the power to satisfy Xcel's ratepayer's needs pursuant to Xcel's 2004 resource plan; and

2. There should be a maximum amount of power produced by natural gas under this PPA.

Examples of items that should be negotiated and/or addressed in some manner are discussed by other intervenors such as Elion Amit and Karen Hyde.

On behalf of customers, I look forward to discussing and reviewing a revised PPA, which better meets the public interests involved.

1. Executive Summary

Northern States Power Company d/b/a Xcel Energy ("Xcel Energy" or "Company") submits to the Minnesota Public Utilities Commission ("MPUC" or "Commission") our 2002 Resource Plan for consideration and approval. This Plan covers the period 2003 - 2017 and identifies a number of issues and risks that will significantly affect the reliability and economy of our customer's electrical energy supply. We look forward to discussion of this plan with stakeholders.

As in previous filings, this Plan presents our analysis of customer needs and resource options under a variety of assumptions to assist in selecting an appropriate path for resource acquisition. More so than previous plans, however, this Plan highlights critical decisions to be made within the five-year planning horizon that will significantly affect our future resource mix. Central among these decisions are:

- The future of our Prairie Island nuclear power plant, which will largely determine the future of nuclear generation in Minnesota.
- Whether the Commission approves our proposed 500-MW contract with Manitoba Hydro.
- The selection and ultimate acquisition of resources from our 2001 All-Source Bidding.
- The future of several key coal-fired power plants, which we have proposed to convert to natural gas and/or install state-of-the-art pollution control equipment.
- What framework of environmental, wholesale market, and transmission regulations will be in effect during the planning period.

In addition, we face normal planning risks (such as forecast risks) and decisions (such as what forecast confidence level to select for determining resource need).

Given the significant number of important issues to be addressed in the near future, our key objectives are to:

- *Anticipate the impacts and consequences of the various possible combinations of resource and regulatory options, and*
- *Ensure that we have adequate, affordable, and environmentally responsible resources to meet our customers' needs.*

Our five-year action plan focuses on managing through this period to ensure continued reliable, economic, environmentally sound service to our customers.

Not all of these decisions will be made by the Commission in this proceeding. Indeed, nuclear issues must be addressed by the Minnesota Legislature, given existing laws. Others are pending before the Commission in other proceedings, such as our Emissions Reduction Proposal (Docket No. E002/M-02-633) and the Manitoba Hydro contract (Docket No. E002/99-888), or may be primarily subject to federal regulation, such as environmental regulations and wholesale market design.

As such, this Plan is complex and will be considered in multiple forums. This Resource Plan attempts to provide a comprehensive view of these issues. As in prior years, we have analyzed a number of scenarios for consideration, modeling various assumptions regarding customer demand, the availability of resources, environmental policy, and market changes. In addition, we undertook significant modeling of various potential outcomes of decisions regarding nuclear power and pending Commission decisions. We believe our Plan presents information important to state policy makers, which we hope will help inform the debate regarding our energy future.

Five-Year Action Plan

To successfully manage our resources through a period of significant risk and uncertainty and to ensure we have adequate resources available to meet our customers' needs, we propose the following five-year action plan:

- *Continue to aggressively pursue the conservation and load management goals established in the 2000 Resource Plan Proceeding.* To date, we have been successful in meeting the goals established in the previous plans. We intend to continue to develop new programs to ensure that we continue to meet these goals as cost-effectively as possible.

- *Obtain Commission approval of the Manitoba Hydro 500-MW contract.* This approval would complete the 1999 All-Source Bidding process and address resource needs beginning in 2005.

- *Complete the 2001 All-Source Bidding process in 2003.* This process, stemming from our last Resource Plan, seeks to secure up to 1,000 MW of additional resources. We are near final selection in this process. Successful completion is needed to ensure adequate supply resources in the 2005 – 2009 timeframe.

- *Obtain approval of our Emissions Reduction Proposal.* This Proposal provides 1,500 MW of environmentally sound, long-term supply, a net increase of approximately 300 MW over the existing plants. While the Commission will decide this matter in a separate proceeding, we include it in our recommended action plan. We believe this Proposal offers significant benefits to our customers.

- *Seek resolution of the future of nuclear generation in Minnesota by the legislature in 2003.* Our analysis indicates that an electricity future that includes nuclear generation is preferable to one that requires shutdown of our Prairie Island and Monticello plants. We have also identified options for replacement resources. Implementing a replacement to Prairie Island's generation will take time, and our analysis indicates significant transmission improvements will be needed as well. Given current Minnesota law, action by the legislature will be required to address this issue, and we intend to provide various options for consideration. Our five-year action plan in this proceeding, however, will be significantly impacted by the outcome of this consideration.

- *Initiate an All-Source Bidding process in 2005 for up to 450 MW of generation to be in service between 2011 and 2013.* We plan to issue this solicitation with sufficient lead-time to accommodate competition from base load resources. We project a need for additional resources beginning in 2011.

- *Continue to closely monitor and manage the transition to new market and regulatory structures.* Dramatic industry changes brought about by new federal regulations will continue to influence our ability to plan for, acquire, construct, and transmit electricity. At the time of our last Resource Plan, the Federal Energy Regulatory Commission had just issued Order 2000, requiring Regional Transmission Organizations ("RTOs"). Now, the Midwest Independent System Operator ("MISO") has commenced operations and independent transmission companies such as TRANSLink have been approved to provide certain RTO services. We expect that restructuring of the transmission function and change over to new organizations will continue to evolve over the coming years. This transition must be closely monitored to ensure that acquisition of needed supply resources can occur in a timely and efficient manner under the new structure. Xcel Energy anticipates filing its TRANSLink proposal, which is designed to help bridge some of these issues, with the Commission yet in December. Likewise, changes to environmental regulations could have significant impact on our resources, and should be carefully monitored.

While these action items seek to implement our preferred course, we recognize the uncertainty over whether all components will be approved and successfully accomplished. Therefore, we have also developed plans to help hedge this risk, making available options that will allow us to best meet our customer needs. These plans include:

- *If continued operation of our nuclear plants is not the State's preferred option, seek legislation expediting the Prairie Island alternative and begin the solicitation process in the 2003 – 2004 timeframe for replacement of Monticello's output in 2010.* We plan to seek approval from the Commission of the PI Contingency finalist list and move forward with negotiations with the selected bidder(s) in order to maintain our options. In the event that the State does not agree with our preference for continued operation of nuclear generation, we will seek relief to provide timely siting and permitting of the Prairie Island replacement generation and transmission infrastructure. Continued operation of the Monticello nuclear generating plant beyond 2010 also depends on additional on-site dry storage if no out-of-state alternative is available. To ensure continued reliable supply, we would begin the resource acquisition process to replace the output from Monticello, which exhausts its storage capabilities in 2010.

- *Establish an acquisition strategy for up to 500 MW of potential additional generation to as a hedge against the uncertainties and risks during this planning period* Seeking resources that offer implementation flexibility would enhance our ability to have available sufficient resources in the event any component of our Preferred Plan fails to develop or other risks materialize. Possibilities for this acquisition strategy include a Request for Proposals for contingency capacity, as is being done for Prairie Island, or rapid development of additional Company-owned resources. Such a strategy will provide an important hedge on the risks identified in this Plan, including forecast risk.

- *Conduct a competitive solicitation program for up to 100 MW of biomass generation resources as a backstop so that we can respond quickly should current market conditions create difficulty for pending biomass projects.* Of three projects currently under contract for 125 MW, only one (25 MW St. Paul District Energy) is financed and under construction. Changing independent power producer market conditions could conceivably impact the remaining two. To enhance our ability to respond quickly to meet our biomass objectives in the event of changed circumstance we intend to develop and pursue additional biomass resource bidding as a backstop.

- *Conduct periodic assessments to consider the combined impacts of the many events that will be occurring on our system* We will continue to carefully monitor developments affecting our system. To the extent that we need to act in response to any development in a way not addressed by this Resource Plan, we will file with the Commission under Minn. Rule 7543.0500, Subd. 5 for a notice of changed circumstance. Careful monitoring and prompt action will be required to ensure we successfully manage resources during this period.

We recognize that others may view these issues differently and come to different conclusions. We welcome the opportunity to engage in a dialogue of these issues and work toward ensuring continued reliable, economical, and environmentally sound energy for our customers.

Chapter Summaries

To assist in understanding the key components of our proposed Resource Plan, we provide the following summaries of each chapter of this filing.

Electric Energy and Peak Demand Forecast

In general, our forecasted needs for energy and capacity remain comparable to the projections made in our 2000 Resource Plan. We used slightly different forecasting methods in this Plan than in previous filings, responding to issues raised by parties in our 2000 Plan.

Our current projections place the median forecast of native *energy requirements* at an average annual growth of 1.7 percent over the 2003 – 2017 forecast period, compared to an average annual growth rate of 1.65 percent in the 2000 – 2015 period covered by the previous plan. The median base *peak demand* forecast shows an average annual growth rate of 1.6 percent, compared to a 1.63 percent average annual growth rate in the 2000 Resource Plan. The difference in growth over the years from 2003 through 2008 between the 2000 Resource Plan forecast and this Resource Plan forecast is only 22 MW.

Xcel Energy supplements the median forecasts with two others to measure uncertainty and quantify uncertainty and errors in the models used to forecast electricity sales and peak demand. These forecasts predict system demand will increase at a rate between 1.4 and 1.8 percent per year, with a base of 8,637 to 9,309 MW of predicted demand in 2003. Figures 1-1 and 1-2 show the 2003 through 2017 long-range forecast of net energy requirements and net summer peak demand for the three forecasts.

Figure 1-1
Xcel Energy Net Energy (MWh)

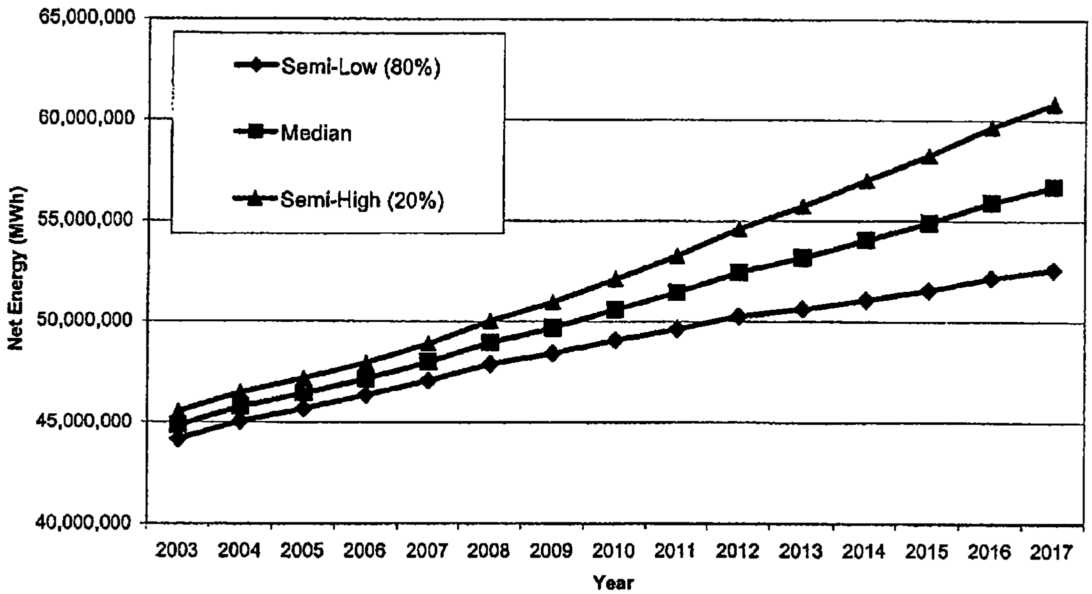
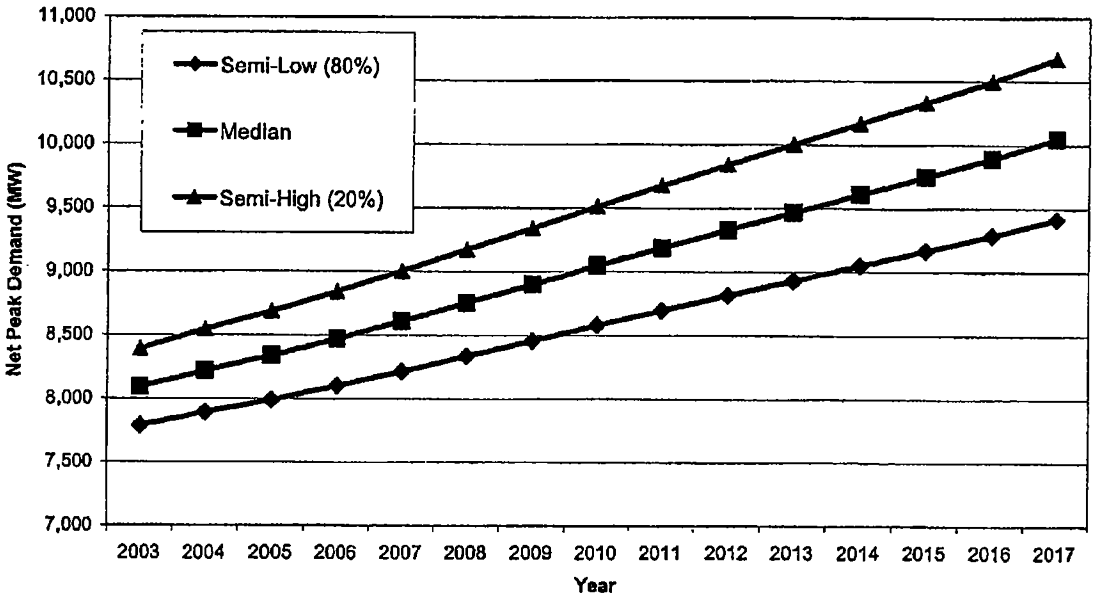


Figure 1-2
Xcel Energy Net Summer Peak Demand (MW)



Resource Needs and Action Planning

Xcel Energy may need up to 4100 - 5800 MW of new capacity by 2017. The resource need over the next five years depends on decisions to be made by Xcel Energy, the Commission, the Legislature, and other entities. Therefore, identification of resource needs is considerably more uncertain in this Plan than prior submissions. Key issues include: whether Prairie Island will continue to operate, how many megawatts will be procured in the 2001 competitive bidding solicitation, whether the pending 500 MW contract with Manitoba Hydro will be approved, and whether the Emissions Reduction Proposal will be approved. A number of these issues will be resolved within the coming year.

Depending on the resolution of these issues, our resource need by 2007 could range from 0 MW to over 1800 MW of capacity. Close monitoring and contingency plans will be important to ensuring that we can respond appropriately as these outcomes are decided.

In this Resource Plan, we advocate issuing an All-Source RFP in 2005 for up to 450 MW of capacity to be available beginning in 2011. In addition, we seek to develop an acquisition strategy for up to 500 MW of contingent capacity, potentially through an RFP for contingent power or the development of additional Company-owned generation. Such a strategy will allow us to better manage risk and provide an important hedge, given the significant uncertainties during this planning period. Having more potential suppliers in the event other projects fail to materialize or demand exceeds our forecast will benefit our resource acquisition efforts.

Resource Plan Analysis

Having identified expected need, Xcel Energy tests a spectrum of resource combinations that might be used to meet future electrical demand, allowing the impacts of various energy policy objectives to be tested. This analysis provides the basis for developing a robust action plan that will serve our customers well while furthering public policy objectives.

In this Resource Plan, we present many scenarios for consideration. The significant number of scenarios evaluated is indicative of the amount of potential variability and risk we see in this planning period. Therefore, we present analysis of the effects of: variability in the future demand for electricity; various renewable energy scenarios; and various nuclear power scenarios. We also examine the potential impacts various environmental strategies could have on the Minnesota's economy and power supply decisions.

Demand-Side Management

As in our most recent Plan, we anticipate that it will become increasingly difficult to cost-effectively acquire additional DSM on our system. While demand-side management offers a number of advantages to our system and our customers, it can also pose implementation issues, particularly as we begin to saturate the market for particular technologies.

At present, however, we have met the aggressive goals adopted in the 2000 Resource Plan. We believe it is appropriate to continue to operate under these goals at this time, and seek Commission approval for continuation of these goals in our current Plan.

Fossil-Fuel Resources

Xcel Energy currently has 3,758 MW (summer rating) of coal-fired generation on our system. With respect to this existing fleet, we recently completed the conversion of Black Dog Units 1 and 2 from coal to natural gas. During the upcoming planning period, we expect that more change will occur within our coal fleet through the Emissions Reduction Proposal, which would convert the High Bridge and Riverside plants from coal to natural gas in 2008 and 2009 and substantially refurbish the King Plant with new pollution control equipment in 2007. We have assumed that all other coal plants continue to operate through the planning horizon without any major changes in O&M expenses or capital commitments. We will, however, continue to make incremental improvements at existing plants when cost effective.

With respect to natural gas-fired generation, Xcel Energy currently has 1,277 MW of on our system, including 987 MW of combustion turbines and 290 MW of combined cycle plant. We have assumed all these plants operate through the planning horizon without any major changes in O&M expenses or capital commitments.

Nuclear Generation and Its Alternatives

Xcel Energy's current resource mix includes the Prairie Island ("PI") and Monticello nuclear plants. Minnesota law limits the amount of spent nuclear fuel storage at these plants, such that the PI plant will need to shut down in 2007 without legislative action. Monticello may operate until end of license (2010), but would not have the capability of seeking license extension (required to be filed in 2005). Therefore, electricity supply issues in the middle part of the planning period will be largely influenced by whether nuclear generation will continue to be part of the state's resource mix.

Our Plan provides information regarding the status of initiatives to provide storage and disposal of spent nuclear fuel and analysis of the options available to Minnesota policymakers regarding nuclear generation and its alternatives. Our analysis indicates that an electricity future that includes nuclear resources is preferable to one that requires shutdown of these facilities. The Plan provides detail on the options Xcel Energy will present to the Minnesota Legislature in the 2003 Session.

Spent Fuel Storage: Since our last Resource Plan, Congress authorized the Department of Energy's ("DOE") permanent spent fuel repository at Yucca Mountain, Nevada. While this milestone is significant, the repository will not be available to address the needs of PI and Monticello during the planning period. Although less promising than reported in our previous Resource Plan, Private Fuel

Storage ("PFS") solution remains a potential interim solution. PFS anticipates that the Nuclear Regulatory Commission ("NRC") will issue a license for the facility in 2003, such that the storage facility could be operating by the end of 2005. The project will continue to face political and legal challenges, as well as uncertainty as to whether it can attract sufficient customers. The progress on Yucca Mountain may cause many utilities to defer to the Yucca site rather than using off-site, interim storage. While we continue to believe PFS is a viable initiative and we intend to continue to pursue development of the project, we can no longer make planning decisions under the assumption that it will exist. Given the status of both the federal and private initiatives, the Minnesota Legislature will need to resolve the future of nuclear generation in this state absent a 2007 out-of-state spent nuclear fuel solution. We will present our analysis and potential options for consideration by the 2003 Minnesota Legislatures.

Steam Generator Replacement: Our analysis indicates that Prairie Island can produce power more economically if steam generators are replaced. However, it would not be economical to invest in new steam generators if the plant must shut down in 2007 due to spent fuel storage limitations. The most advantageous course is to replace steam generators in Unit 1 in 2004. We have taken incremental steps to preserve our ability to do that. However we have reached a point at which a decision whether to continue must be made. That decision necessarily depends on spent nuclear fuel decisions to be made by the legislature.

Relicensing: Applications must be made to the NRC five or more years before the current licenses expire and the work to prepare applications takes approximately two years. Therefore, Xcel Energy must decide soon whether to continue the process of application preparation for relicensing for the Monticello plant, or alternatively commence decommissioning planning. To date, 26 nuclear power plant licensees have made application for 20-year extensions to their operating licenses; 26 others have announced their intention to apply. Licenses have been renewed at five nuclear generating plant sites.

In this resource plan we examine a variety of alternatives to replace Prairie Island should it become necessary. Xcel Energy has received bids for the replacement of Prairie Island in a special competitive bidding process designed for that purpose. We anticipate finishing the selection process soon and continuing through the rest of the process as expeditiously as possible to preserve our ability to replace Prairie Island if necessary. The bids available to us consist of new gas- and coal-based generating plants. All require substantial transmission investments to ensure system reliability as the result of the significant change in the operating dynamics of the grid resulting from the absence of Prairie Island.

In addition, we have explored the feasibility of repowering Prairie Island as a natural gas fired facility. While nuclear power plants have been repowered, such a conversion has never been done seamlessly. Rather, gas conversion has only taken place after decommissioning is well advanced, several years after operations cease. Repowering does not appear to be a replacement option but may be a strategy to consider in order to make use of the site's infrastructure in the future.

Our comparative analysis of the replacement alternatives and continued operation indicates that the cost of electricity will be more economical with nuclear generation than without it. We also found the emission of fossil fuel related pollutants and green house gases to be lower with a nuclear generating component in our resource mix. We believe the risks associated with nuclear generation are manageable. We also conclude that the difference in the amount of spent nuclear fuel produced as the result of early shutdown is small and does nothing to address the fundamental responsibilities we as a nation have to properly manage and dispose of radioactive wastes. However, if Minnesota does not agree, we are prepared to pursue the resources necessary to replace our nuclear generating plants.

Renewable Energy

Xcel Energy's use of renewable energy is expected to increase during the planning period. We anticipate that biomass facilities developed pursuant to 1994 Minnesota legislation will begin to operate during this period. We anticipate that additional wind resources will be procured under the All-Source Bidding processes, both underway and planned. Due to the relative costs of various renewable energy resources, we expect that most renewable energy additions will be wind. We continue to believe that All-Source Bidding is the most appropriate means for determining additions to our resource mix, including renewable energy.

Other developments regarding renewable energy since our last Resource Plan include: adoption of renewable energy objectives by the Minnesota Legislature; implementation of a tariff for small wind producers to allow for streamlined connection to our distribution system; approval of our green-pricing offering; and awards of the first round of funding under the Renewable Development Fund, which has selected 19 projects for grants totaling $16 million for renewable energy projects.

Environment

Xcel Energy's fossil-fueled plants continue to comply with environmental regulations. Since our last Resource Plan, we have implemented several pollution-control equipment installations at our plants, submitted a voluntary mercury reduction plan, and proposed significant projects at the King, High Bridge, and Riverside plants under the Emissions Reduction Rider statute.

There is uncertainty in predicting the future of environmental compliance regulations. Consequently, we modeled various scenarios of potential future regulations to assess their impacts. This analysis shows that independent actions of either Minnesota or the United States will have more of a detrimental impact on the state's economy than operation under international environmental agreements would have. In addition, we provide various analyses in compliance with the

Commission's Order in our most recent Resource Plan regarding alternative environmental scenarios.

Transmission Impacts Associated with Generation Decision Making

Like other utilities in the country, Xcel Energy's transmission system is operating with very little excess capacity. Major improvements will be necessary as generation is added and customer demands continue to grow. The new market created by Open-Access transmission tariffs have increased the volume of transactions often to the point of raising the transmission network loading to its limits, such that line-loading relief and curtailment procedures are implemented more frequently than ever before. Implementation of RTOs, the start-up of MISO, and anticipated operation of TRANSLink pose transitional issues that impact resource planning and acquisition. Managing through these transitions as efficiently and effectively as possible will be important. Close monitoring of these transitions will be needed.

Legislative and Regulatory Changes have been made that require a separate Minnesota Transmission Planning proceeding. Minnesota transmission providers must now file a report on November 1 of odd numbered years outlining the system deficiencies their planning must address and potential solutions. The inaugural State Transmission Planning Report was filed November 1, 2001, and rulemaking is underway to guide future transmission planning dockets.

In this Resource Plan we provide a general discussion of the transmission implications associated with the generation decision making discussed throughout the plan. New high voltage transmission lines will be needed to support just about any large generation addition to the system. The actual requirements are very dependent on the specific site, size and operating characteristics of the proposal.

In general, small increments of additional electric power can probably be delivered within the Twin Cities metropolitan area without significant transmission investments. However, large units, approaching 400 – 500 MW in size, will probably require new transmission lines so that the added electrical power can be injected at more than one point in the interconnected electrical grid. Remote large generators (for example wind or coal-based plants in the Dakotas or additional purchases from Canada) will require new longer, and therefore more expensive, high-voltage transmission lines.

Distributed Generation

Much work has been completed since the last Resource Plan to facilitate the addition of distributed generation resources on our system. Key among these include implementation of our tariff for projects 2 MW and under, and the work to establish generic state standards for projects sized up to 10 MW. Straightforward processes to connect distributed resources to our system are important to encouraging their development.

While we do not expect that distributed generation will provide a significant portion of our resource needs in the near future, we are working to support its implementation. In this chapter, we provide a summary of the pilot projects underway as part of our approved Conservation Improvement Plan.

Conclusion

Xcel Energy appreciates this opportunity to present this Resource Plan to the parties and decision makers. We believe that a successful Resource Plan will allow us to successfully manage our resources through risk and uncertainty and ensure that we have ample, viable resources available to meet our customers' needs. Our five-year action plan focuses on managing through this period to ensure continued reliable, economic, environmentally sound service to our customers.

We look forward to discussion of our action plan with key stakeholders and decision makers. We recognize that others may view these issues differently and come to different conclusions. We welcome the opportunity to engage in a dialogue of these issues and work toward ensuring continued reliable, economical, and environmentally sound energy for our customers.

2. Electric Energy and Peak Demand Forecast

- *We project an energy growth rate of 1.68% (average annual) over the planning period.*
- *We project a peak demand growth of 1.6% (average annual) over the planning period.*
- *Our forecast methodology no longer involves separate short- and long-term forecasts.*

Xcel Energy prepares a 15-year forecast of the demand for electricity as part of the bi-annual resource planning process. The Commission reviewed our forecast methodology in the 2000 Resource Plan and approved it with minor modifications. We prepared the current Resource Plan forecast using a slightly different methodology. The change in methodology responds to comments received on the 2000 Resource Plan and was presented to the Department prior to preparation of this Plan.

Results

The median forecast of native energy requirements for the Xcel Energy – North[1] service territory has an average annual growth of 1.68 percent over the forecast period 2003 – 2017. This forecast is similar to the 2000 Resource Plan, which had an average annual growth rate of 1.65 percent from 2000 – 2015.

System peak demand is the maximum demand for capacity faced by the Xcel Energy – North system. Xcel Energy must be prepared to meet this demand through generation, purchases, or load-management programs. Our maximum demand occurs in the summer, during periods of hot and humid weather.

The median base peak demand forecast shows an average annual growth rate of 1.60 percent between 2003 and 2017. This is comparable to a 1.63 percent average annual growth rate from the 2000 Resource Plan. The difference in growth

[1] "Xcel Energy – North" refers to the five-state electric service territory of Northern States Power Company (Minnesota, North Dakota, and South Dakota) and Northern States Power Company – Wisconsin (Wisconsin and Michigan).

between the 2000 Resource Plan forecast and this Resource Plan forecast for the period 2003 - 2008 is only 22 MW on a 9,700-MW base.

Xcel Energy has had load-relief programs, or interruption of load during hot summer weather, for several years. Participation in the programs has grown significantly, and we adjust our peak forecast to reflect this decrease in demand. The resulting median net peak demand is expected to grow 1.55 percent annually over the planning period versus 1.50 percent in the 2000 Plan.

Forecast Methodology

Xcel Energy's forecast is prepared by major customer class sector and by jurisdiction using a variety of statistical and econometric techniques.

We develop our system median sales forecast by using a set of econometric models at the jurisdictional level for the Residential, Small Commercial and Industrial, and Large Commercial and Industrial sectors. These models relate Xcel Energy's historic electric sales to economic and demographic variables such as prices, income, employment, number of customers, and weather. Trending is used for the remaining sectors: Public Street and Highway Lighting, Other Sales to Public Authorities, Interdepartmental, and Firm Wholesale. We then compile our system sales by summing the individual forecasts for each sector in each jurisdiction.

Loss factors are used to convert the sales forecasts (obtained from the econometric models) into annual energy requirements (at the generator). It is assumed that these loss factors will hold constant over the forecast period. An econometric model was developed, with native energy requirements as a key driver, to forecast base peak demand in the Xcel Energy - North service territory.

A more complete documentation of the econometric modeling used to develop Xcel Energy's forecast of electric energy and peak demand is included in Appendix A.

Key Variables

Following is a discussion of some of the key demographic and economic variables affecting the 2002 Resource Plan forecasts.

Demographic Assumptions: Population projections are essential in the development of the long-range forecast. The forecasts of residential customers are derived from population and number of household projections at the state level provided by Data Resources, Inc. – Wharton Econometric Forecasting Associates[2] ("DRI-WEFA"). The number of residential customers is the key variable in the residential MWh sales forecasts. Xcel Energy forecasts an annual growth rate for the number of total system residential customers of 1.19 percent, or approximately 17.9 percent over the period 2003 – 2017.

Economic Assumptions: Xcel Energy used forecasts of several key economic indicators as received from DRI-WEFA, including gross state product, employment, and productivity. Most variables used were specific to the jurisdiction, and proved key in the sales forecast of the commercial and industrial customer classes.

Electricity Prices: Xcel Energy created historic prices by calculating a price per MWh from billing information at the customer class and jurisdictional level. We then used the wholesale price index for electricity as created by DRI-WEFA to determine the forecast.

Forecast Variability

As a measure of the uncertainty in any forecasting effort, Xcel Energy prepared a semi high and semi low forecast. The semi high forecast (20% forecast) is that level of energy consumption and power demand that is likely to be exceeded only 20 percent of the time. The semi low forecast (80% forecast) is that level of

[2] DRI-WEFA has recently merged and changed the company name to Global Insight.

power demand and energy consumption that is likely to be exceeded more than 80% of the time.

These forecasts predict system demand will increase at a rate between 1.40 and 1.80 percent per year, with a base of 8,637 to 9,309 MW of predicted demand in 2003. Tables 2-1 and 2-2 and Figures 2-1, 2-2 and 2-3, and show the 2003 to 2017 long-range forecast of net energy requirements and summer peak demand for the three forecasts.

Table 2-1 Xcel Energy
2003 Long Range Forecast

Annual Net Energy (MWh)

	Semi-Low (80%)	Median	Semi-High (20%)
2003	44,154,985	44,843,980	45,532,978
2004	45,057,594	45,777,599	46,497,608
2005	45,672,494	46,430,154	47,187,812
2006	46,350,252	47,154,797	47,959,342
2007	47,072,332	47,984,010	48,895,690
2008	47,879,117	48,950,604	50,022,089
2009	48,419,144	49,689,519	50,959,891
2010	49,077,644	50,590,274	52,102,904
2011	49,635,225	51,449,293	53,263,364
2012	50,263,086	52,443,251	54,623,415
2013	50,621,610	53,172,225	55,722,846
2014	51,089,639	54,054,566	57,019,494
2015	51,563,357	54,913,439	58,263,524
2016	52,179,777	55,927,765	59,675,752
2017	52,589,962	56,705,792	60,821,624
Average Growth 2003-2017	1.25%	1.68%	2.07%

Table 2-2 Xcel Energy
2003 Long Range Forecast

Annual Base Summer Peak Demand (MW)

	Low (80%)	Median	High (20%)
2003	8,637	8,973	9,309
2004	8,770	9,134	9,498
2005	8,902	9,289	9,676
2006	9,037	9,451	9,864
2007	9,177	9,617	10,057
2008	9,315	9,782	10,248
2009	9,452	9,945	10,439
2010	9,592	10,113	10,634
2011	9,724	10,271	10,817
2012	9,857	10,430	11,003
2013	9,987	10,586	11,185
2014	10,119	10,744	11,369
2015	10,247	10,898	11,549
2016	10,380	11,058	11,735
2017	10,520	11,226	11,932
Average Growth 2003-2017	**1.41%**	**1.60%**	**1.77%**

Annual Net Summer Peak Demand (MW)

	Low (80%)	Median	High (20%)
2003	7,787	8,090	8,393
2004	7,894	8,221	8,549
2005	7,991	8,338	8,686
2006	8,102	8,472	8,843
2007	8,215	8,609	9,003
2008	8,336	8,754	9,171
2009	8,457	8,898	9,339
2010	8,581	9,047	9,512
2011	8,697	9,186	9,675
2012	8,815	9,328	9,840
2013	8,931	9,467	10,003
2014	9,050	9,609	10,168
2015	9,166	9,748	10,330
2016	9,287	9,893	10,499
2017	9,416	10,048	10,680
Average Growth 2003-2017	**1.36%**	**1.55%**	**1.72%**

Figure 2-1
Xcel Energy Net Energy (MWh)

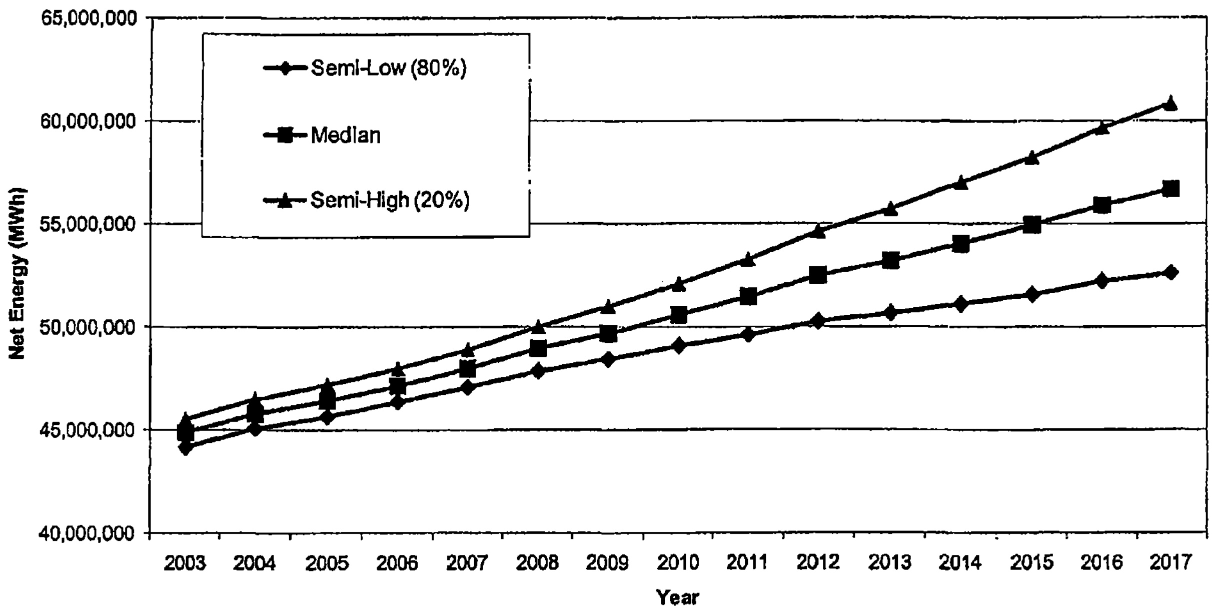


Figure 2-2
Xcel Energy Base Summer Peak Demand (MW)

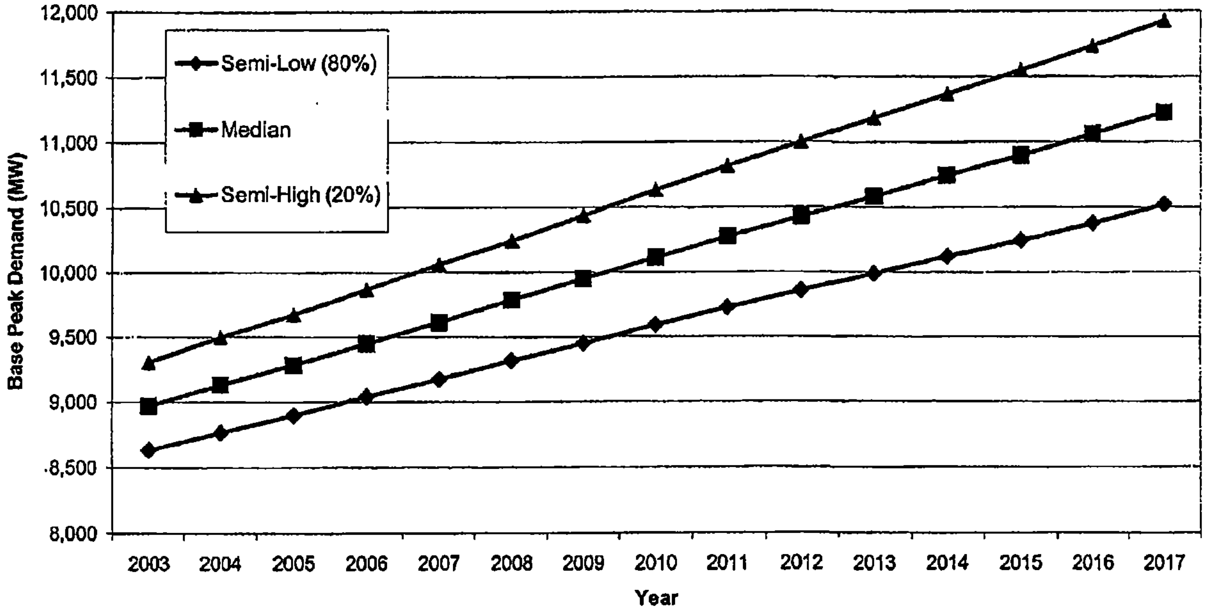
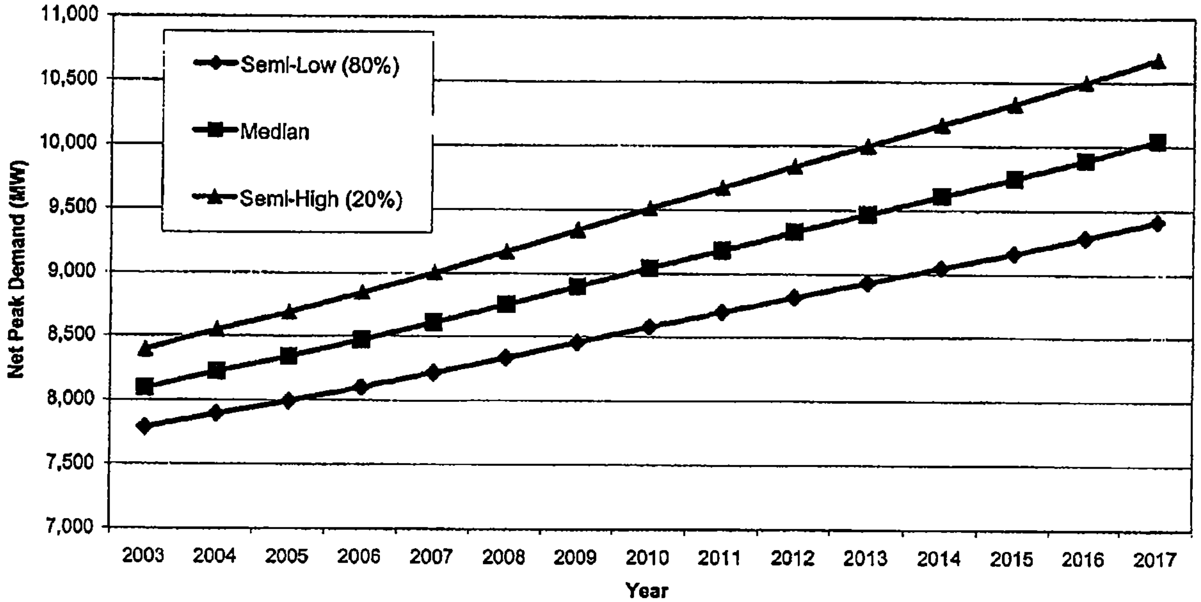


Figure 2-3
Xcel Energy Net Summer Peak Demand (MW)



Forecast Compliance Issues

We met with the staff of the Department of Commerce ("Department") to discuss the recommendations from the 2000 Resource Planning process and present our plan for addressing these. Issues addressed the Department are discussed below.

Calibration Methodology: The Department disagreed with how Xcel Energy calibrated the short- and long-term forecasts in the 2000 Resource Plan. For the 2002 Resource Plan, we created one forecast for each customer class and jurisdiction for the entire planning period, eliminating the need for calibration. Because we no longer need to calibrate short-term and long-term forecasts, the explanation of that process is appropriately removed from the documentation.

Inconsistent Methodologies: The Department suggested the methods used to create the peak demand forecast in the short- and long-term forecasts were inconsistent. For the 2002 Resource Plan, we are no longer using load factors to create peak demand forecasts. Rather, we are using an econometric model to forecast peak demand for the entire planning period and have included the model and data series in Appendix A.

Language Clarification: The Department suggested a clarification in the language regarding the short-term sales and peak demand methodologies. We have modified the forecast process, eliminating the need for both a short-term and long-term forecast and thus a calibration of the two forecasts. The current methodology is described at length in Appendix A.

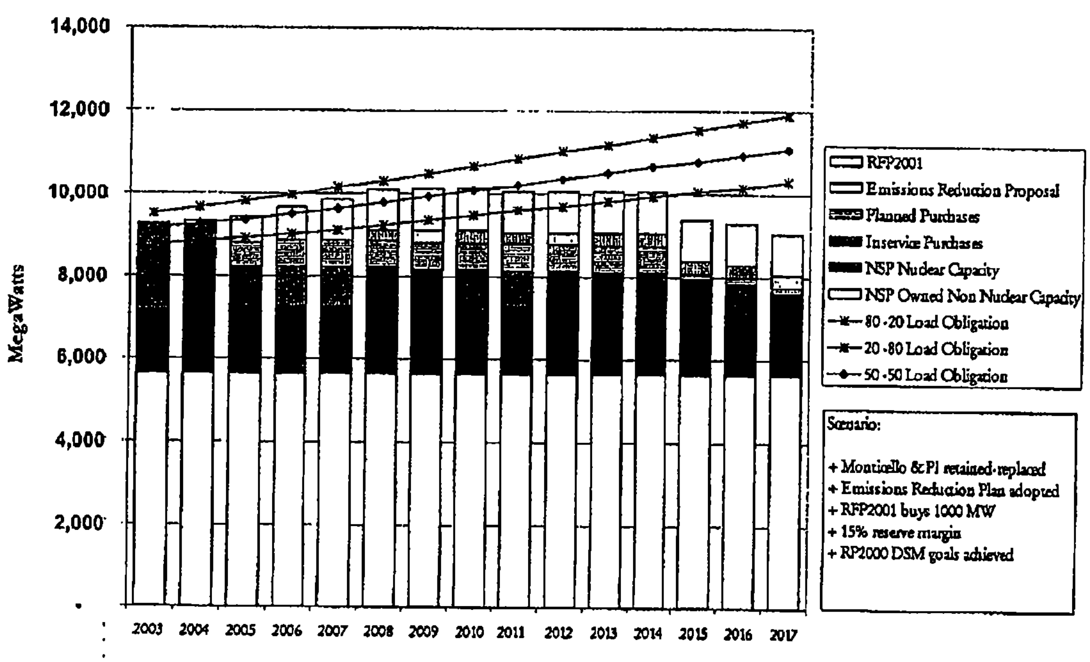
3. Resource Needs and Action Planning

- *Additional resources are required to meet our customers' requirements.*
- *Our plans focus on meeting customer requirements in an affordable, reliable, and environmentally responsible manner.*
- *Creating a process for ensuring the availability of additional resources should our plans fail to deliver expected capacity and energy is an important component of our action plan.*

Figure 3-1 presents the results of Xcel Energy's forecast of production capacity requirements compared to existing generation resources and pending generation acquisitions.

Figure 3-1

Resource Need



The forecast lines in Figure 3-1 reflect the demand-side management goals resulting from the 2000 Resource Plan proceeding and the 15% generation reserve requirement. After adjustments, Xcel Energy's median forecast predicts the peak demand for electricity will be 9,128 MW in 2003, 10,070 MW in 2010, and 11,096 MW in 2017. On the supply side, Xcel Energy owns approximately 5,800 MW of existing non-nuclear accredited production capacity and approximately 1,700 MW from Prairie Island and Monticello nuclear plants. Existing power purchases amount to 1,980 MW in 2003 but decline over time as purchase agreements expire.

Based on our forecasted demand and expected available resources, we anticipate the need to issue an All-Source Bid solicitation for approximately 450 MW in 2005 for resources to be placed in service between 2011 and 2013. This expected need and acquisition plan assumes successful completion of a number of our pending initiatives, including the outcome of several on-going acquisition programs, the decisions concerning the conversion and upgrade of existing plants in the Emission Reduction Proposal (Docket No. E002/M-02-633), and the Legislature's consideration of the future of nuclear generation. If any of these initiatives fail to deliver the expected energy and capacity, we will require additional replacement resources. Reaching consensus on an action plan to hedge this risk will be important to ensuring we are able to reliably and cost-effectively meet our customers' needs.

Issues and risks during the planning period that may affect our expected resource needs include:

- *DSM Risk.* Our forecasts rely on our ability to achieve an additional 50 to 80 MW of peak reduction each year due to conservation and load management. Based on our research, we believe it will become increasingly difficult to maintain this pace of DSM.

- *Developer Risk.* There are on the order of 1,900 MW in our anticipated power supply portfolio currently in development, contracted but not yet under construction, or yet to be secured in ongoing acquisition dockets. There is risk that some portion of those anticipated resources may not be implemented, despite our best efforts.

- *Existing Supply Risks.* Our Emission Reduction Proposal would provide 1,525 MW of capacity over the planning period, an increase of approximately 300 MW over the capacity of the existing plants. If the Commission does not adopt our Proposal, our resource need will grow.

- *Storage Capacity Risks.* Prairie Island does not have the ability to operate beyond 2007 unless additional spent fuel storage becomes available. If out-of-state spent fuel storage is not an option by that time and the Minnesota Legislature does grant additional storage, the output from Prairie Island must be replaced. If additional storage is not authorized for Prairie Island, it is unlikely Monticello would be able to operate beyond 2010 since it would also require additional spent fuel storage by that time.

- *Short-term Supply Risks.* Xcel Energy has traditionally met its median forecast with long-term supplies. We then make short-term purchases to cover variations due to weather, load forecast, forced plant outages, and wholesale market fluctuations. Our short-term purchases have increased dramatically in recent years. Increasing transmission constraints have restricted import of short-term purchases to our system. Additional long-term supplies coupled with additional transmission capacity may be needed to ensure continued reliable access to supplies.

Given these pending issues and uncertainties, we believe it is prudent to acquire – in an effort separate from the 450-MW solicitation identified above – up to 500 MW of additional long-term resources, provided we can achieve flexibility regarding timing of those resources. We believe we can achieve this needed flexibility in a number of ways, either individually or in combination. We could design an RFP similar to the Prairie Island contingent-bidding program. In that case we asked developers to provide bids that included cancellation provisions. In this case we could similarly seek cancellation and/or delay provisions to give added flexibility. Second, we could pursue staged development of Company-owned resources with short lead times, like natural-gas-fired combustion turbines deployed at existing power plant sites. We believe there are other flexibility strategies that could be explored. We welcome comment and discussion during consideration of this Resource Plan. We believe that achieving consensus and approval of a plan to hedge these risks is needed to ensure adequate supply of reliable, economic power to meet our customers' needs.

Five-Year Action Plan

To successfully manage our resources through a period of significant risk and uncertainty and to ensure we have adequate resources available to meet our customers' needs, we propose the following five-year action plan:

- *Continue to aggressively pursue the conservation and load management goals established in the 2000 Resource Plan.* To date, we have been successful in meeting the goals established in the previous plans. We intend to continue to develop new programs to ensure that we continue to meet these goals as cost-effectively as possible.

- *Obtain Commission approval of the Manitoba Hydro 500-MW contract.* This approval would complete the 1999 All-Source Bidding process and address resource needs beginning in 2005.

- *Complete the 2001 All-Source Bidding process in 2003.* This process, stemming from our last Resource Plan, seeks to secure up to 1,000 MW of additional resources. We are near final selection in this process. Successful completion is needed to ensure adequate supply resources in the 2005 – 2009 timeframe.

- *Obtain approval of our Emissions Reduction Proposal.* This Proposal provides 1,500 MW of environmentally sound, long-term supply, a net increase of approximately 300 MW over the existing plants. While the Commission will decide this matter in a separate proceeding, we include it in our recommended action plan. We believe this Proposal offers significant benefits to our customers.

- *Seek resolution of the future of nuclear generation in Minnesota by the legislature in 2003.* Our analysis indicates that an electricity future that includes nuclear generation is preferable to one that requires shutdown of our Prairie Island and Monticello plants. We have also identified options for replacement resources. Implementing a replacement to Prairie Island's generation will take time, and our analysis indicates significant transmission improvements will be needed as well. Given current Minnesota law, action by the legislature will be required to address this issue, and we intend to provide various options for consideration. Our five-year action plan in this proceeding, however, will be significantly impacted by the outcome of this consideration.

- *Initiate an All-Source Bidding process in 2005 for up to 450 MW of generation to be in service between 2011 and 2013.* We plan to issue this solicitation with sufficient lead time to accommodate competition from base load resources.

- *Continue to closely monitor and manage the transition to new market and regulatory structures.* Dramatic industry changes brought about by new federal regulations will continue to influence our ability to plan for, acquire, construct, and transmit electricity. At the time of our last Resource Plan, the Federal Energy Regulatory Commission had just issued Order 2000, requiring Regional Transmission Organizations ("RTOs"). Now, the Midwest Independent System Operator ("MISO") has commenced operations and independent transmission companies such as TRANSLink have been approved to provide certain RTO services. We expect that restructuring of the transmission function and change over to new organizations will continue to evolve over the coming years. This transition must be closely monitored to ensure that acquisition of needed supply resources can occur in a timely and efficient manner under the new structure. Likewise, changes to environmental regulations could have significant impact on our resources, and should be carefully monitored.

While these action items seek to implement our preferred course, we recognize the uncertainty over whether all components will be approved and successfully accomplished. Therefore, we have also developed plans to help hedge this risk, making available options that will allow us to best meet our customer needs. These plans include:

- *If continued operation of our nuclear plants is not the State's preferred option, seek legislation expediting the Prairie Island alternative and begin the solicitation process in the 2003 – 2004 timeframe for replacement of Monticello's output in 2010.* We plan to seek approval from the Commission of the PI Contingency finalist list and move forward with negotiations with the selected bidder(s) in order to maintain our options in case the authorization of for additional on-site spent fuel storage is not obtained from the legislature. In the event that the State does not agree with our preference for continued operation of nuclear generation, we will seek relief to provide timely siting and permitting of the Prairie Island replacement generation and transmission infrastructure. Continued operation of the Monticello nuclear generating plant beyond 2010 also depends on additional on-site dry storage if no out-of-state alternative is available. To ensure continued reliable supply, we would begin the resource acquisition process to replace the output from Monticello, which exhausts its storage capabilities in 2010.

- *Establish an acquisition strategy for up to 500 MW of potential additional generation to as a hedge against the uncertainties and risks during this planning period.* Seeking resources that offer implementation flexibility would enhance our ability to have available sufficient resources in the event any component of our Preferred Plan fails to develop or other risks materialize. Possibilities for this acquisition strategy include a Request for Proposals for contingency capacity, as is being done for Prairie Island, or rapid development of additional Company-owned resources. Such a strategy will provide an important hedge on the risks identified in this Plan, including forecast risk.

- *Conduct a competitive solicitation program for up to 100 MW of biomass generation resources as a backstop so that we can respond quickly should current market conditions create difficulty for pending biomass projects.* Of three projects currently under contract for 125 MW, only one (25 MW St. Paul District Energy) is financed and under construction. Changing independent power producer market conditions could conceivably impact the remaining two. To enhance our ability to respond quickly to meet our biomass objectives in the event of changed circumstance we intend to develop and pursue additional biomass resource bidding as a backstop.

- *Conduct periodic assessments to consider the combined impacts of the many events that will be occurring on our system* We will continue to carefully monitor developments affecting our system. To the extent that we need to act in response to any development in a way not addressed by this Resource Plan, we will file with the Commission under Minn. Rule 7543.0500, Subd. 5 for a notice of changed circumstance. Careful monitoring and prompt action will be required to ensure we successfully manage resources during this period.

We look forward to discussion of this action plan with key stakeholders. We recognize that others may view these issues differently and come to different conclusions. We welcome the opportunity to engage in a dialogue of these issues and work toward ensuring continued reliable, economical, and environmentally sound energy for our customers.

4. Resource Plan Analysis

- *The "Strategist" tool has replaced EGEAS, performing the same type of analysis.*
- *We developed a Preferred Plan after developing a Reference Case and modeling various assumptions. We recommend the Commission adopt the Preferred Plan as a basis for decision-making in this proceeding*

After resource needs have been identified, the planning process next investigates resource combinations that might be used to meet future electrical demand. Our analytical tools allow us to determine the most efficient resource mix under a variety of assumptions. With this information, we can compare the economic, environmental, and reliability impacts of various potential energy policy objectives over the planning period.

Modeling Tool

Xcel Energy uses the "Strategist" resource expansion model[3] to analyze various long-range electric supply-demand alternatives. Strategist replaces the EGEAS model that we used in the past, but essentially does the same work. Specifically, Strategist:

- Develops the optimized selection of resources to meet the resource need, given the input assumptions.
- Determines the supply patterns of existing and required new resources to met the identified customer needs.
- Calculates the present value of revenue requirements ("PVRR") to measure the economic impacts of various planning scenarios. (Our reported present values are in 2003 dollars ["2003$"]).
- Calculates environmental impacts of the plan using input externality values.

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[3] "Strategist" is a registered trademark of New Energy Associates, Inc. New Energy Associates developed and maintains the Strategist model.

Our Emissions Reduction Proposal included the results of Strategist analysis, and we have used this model in our evaluation of bids submitted in both the Prairie Island ("PI") Contingency and All-Source Bid processes. We would be happy to provide additional detail on this model, if needed.

Reference Case

To perform the analysis, we first construct a Reference Case against which all other scenarios can be compared. Through comparisons, the supply patterns, relative economic impacts, and environmental impacts of various alternatives under different sets of assumptions can be determined and analyzed. The Reference Case is not necessarily the least-cost plan, but a starting point for the analysis.

Assumptions

The 2002 Resource Plan Reference Case assumes:

- Our median forecast of demand and energy requirements.
- DSM at the level adopted by the Commission in our most recent resource plan, which corresponds to the ordered values of 1,174 MW and 3,253 GWh.
- Continued operation of our existing power plants as currently configured (i.e., without the changes proposed in the Emissions Reduction Proposal).
- PI Units retired in 2006 and 2007; Monticello in 2010.
- The value of unserved energy is $150/MWh.
- Continuation of existing purchased power contracts, and placeholders for 800 MW to represent selections from the 2001 All-Source Bidding process.[4]
- Installation of 480 MW of wind by the end of 2005 and 125 MW of biomass by 2004. We do not assume any additional wind that might be purchased in our 2001 All-Source Bidding program. We model wind using MAPP accredited capability at 10% of nameplate capacity, a $2/MWh ancillary

[4] We used 800 MW instead of the full 1,000 MW potentially sought by the bid to fit with the generic plant size used by the Strategist model.

service charge, and a 25 – 32% annual capacity factor, depending on the size of the installation.

Strategist requires generic resources to meet future demand when installed resources fall short. This Resource Plan uses the following generic resources, developed using information from bidding processes and the Energy Information Agency.

- 200 MW purchase, based on combustion turbines.
- 200 MW purchase, based on combined-cycle generators.
- 450 MW purchase, based on coal-fired generation.
- 400 MW (nameplate) purchase, based on wind resources.

Results

The resulting Reference Case has a PVRR of $14,817 million. Table 4-1 shows the results for the high and low forecasts.

Table 4-1 Strategist Results

Forecast Study Results from Strategist 2002 Resource Plan – Study Timeframe 2003-2017 PVRR in $000,000 (millions of dollars)			
Forecast	PVRR	Low Externalities	High Externalities
Low (80/20)	14,031	14,355	16,102
Reference Case (50/50)	14,817	15,155	16,998
High (20/80)	15,607	15,951	17,843

Compliance Requirements

Order Point 4 of our 2000 Resource Plan Order directed Xcel Energy to present the needs identified by Strategist in baseload, intermediate, peaking, and other categories. In compliance with that Order, we present the following tables. Strategist matches a particular resource to the need, such that coal plants represent baseload, natural-gas combined-cycle generators represent intermediate, and combustion turbines represent peaking. The "Other" category is represented by wind, a resource with a fixed delivery pattern that does not fit a baseload, intermediate, or peaking definition.

**Table 4-2 Incremental Resource Needs (MW)
Reference Plan, Median Forecast**

	Base (Coal)	Intermediate (CC)	Peaking (CT)	Other (Wind*)	Total
2003					0
2004					0
2005		600			600
2006		200			200
2007		400	200		600
2008	902				902
2009					0
2010				40	0
2011	902				902
2012					0
2013	451				451
2014					0
2015	451		200		651
2016			200	40	200
2017	451				451

* Accredited capability; 10% of nameplate capacity.

Table 4-3 Cumulative Resource Needs (MW)
Reference Plan, Median Forecast

	Base (Coal)	Intermediate (CCs)	Peaking (CTs)	Other (Wind*)	Total
2003					0
2004					0
2005		600			600
2006		800			800
2007		1200	200		1400
2008	902	1200	200		2302
2009	902	1200	200		2302
2010	902	1200	200	40	2342
2011	1804	1200	200	40	3244
2012	1804	1200	200	40	3244
2013	2255	1200	200	40	3695
2014	2255	1200	200	40	3695
2015	2706	1200	400	40	4346
2016	2706	1200	600	80	4586
2017	3157	1200	600	80	5037

* Accredited capability; 10% of nameplate capacity.

Comparative Analysis

We next studied many potential changes to the reference case assumptions to explore different ways to meet our customers' needs under a variety of scenarios. We chose the scenarios to model varying potential outcomes of key areas of risk during the planning period. These key risk areas include demand forecast, the Emissions Reduction Proposal implementation, continued nuclear generation, and environmental regulation impacts. Further, because the cost of natural gas can significantly influence PVRR, we ran scenarios of low, median, and high natural gas prices within each of the key areas.

Below we provide a general summary of our comparative analysis in each of these key areas. Details regarding the outcome of these analyses are included in the chapters that follow.

Forecast

To test the sensitivity of resource additions to slower or faster demand growth, Xcel Energy varied the demand forecast by selecting a variety of confidence intervals. In addition to the median forecast, we tested the semi-high ("20-80") and semi-low ("80-20") forecasts. The results of these analyses are contained in Table 4-1 of this Plan.

As discussed above, we based the Reference Case on a median load forecast. Other cases presented in this Resource Plan are based on load forecasts at different points on a normal distribution of weather over the past 40 years. None of these cases accurately predict load patterns we could expect during the extreme summer weather periods that occur every few years in Minnesota. Thus, the Company explored the question of whether the load patterns resulting from these sporadic extreme summer weather periods suggest a different set of resource needs than those identified in the Reference Case.

We used actual weather data for each hour in June, July, and August of the years 1987 – 2001 in our load-forecasting model to simulate load patterns for each summer in the resource planning period (2003 –2017). In other words, 1987 summer weather was simulated in the load forecast model for 2003, 1988 summer weather was simulated in the load forecast model for 2004, and so on to produce simulated summer load patterns for each summer in the planning period. The simulated monthly summer peak load and total monthly energy were then substituted for the summer peak load and energy used in Strategist for the Reference Case. A typical week per month pattern was created based on the simulated peak load and energy along with the load pattern from the Reference Case. Strategist was then allowed to optimize using the same generic units available for the Reference Case optimization. The results of the Summer Simulation Case optimization are presented in Table 4-4.

Table 4-4 Summer Simulation Case
Capacity by Generic Plant Type (MW)

Weather Year	Simulation Year	Coal	CC	CT	Wind*	Total	Cumulative Total
1987	2003		400			400	400
1988	2004			400	40	440	840
1989	2005		600			600	1440
1990	2006		200			200	1640
1991	2007			200		200	1840
1992	2008					0	1840
1993	2009	450				450	2290
1994	2010	450				450	2740
1995	2011	900				900	3640
1996	2012					0	3640
1997	2013					0	3640
1998	2014				40	40	3680
1999	2015	1350			40	1390	5070
2000	2016					0	5070
2001	2017	450		200	40	690	5760
	Total	3600	1200	800	160	5760	

* Accredited capability; 10% of nameplate capacity.

Annual comparisons of resource needs identified in the Reference Case (presented earlier in this chapter) versus the Summer Simulation Case are probably not meaningful because it is unreasonable to expect, as an example, that summer 1988 weather will be experienced again in 2004 or in any other particular year. However, we believe it is instructive to compare resource needs over the entire planning period by resource type and in terms of total resource needs.

The Summer Simulation Case suggests Xcel Energy could have 730 MW more resource needs than the Reference Case has identified if, in fact, actual summer weather patterns from the past 15 years are repeated over the course of the resource planning period (2003 – 2017). This additional resource need would take the form of one additional peaking resource (200 MW), one additional coal resource (450 MW) and two additional wind resources (80 MW accredited). While it is unlikely that the summer weather pattern for the past 15 years will repeat itself exactly over the next 15 years, we have concluded from this preliminary analysis

MCC Exhibit __ (BB Surrebuttal 2)

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☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy		
Docket No.:	E6472/M-05-1993	
Response To:	MN Chamber of Commerce	Information Request No. 23
Date Received:	October 17, 2006	

Question:

What would Xcel do with excess baseload capacity if the Power Purchase Agreement as proposed by Excelsior is approved?

Response:

If there was excess system capacity as a result of the PPA being approved, Xcel Energy would likely try to sell the excess to other utilities in the market.

Response By:	Elizabeth Engelking
Title:	Manager, Resource Planning and Bidding
Date:	October 30, 2006

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy		
Docket No.:	E6472/M-05-1993	
Response To:	MN Chamber of Commerce	Information Request No. 24
Date Received:	October 17, 2006	

Question:

In the event Excelsior does not meet the commercial operation date pursuant to its proposed timeline, how would replacement baseload be acquired, and what would be the cost of that compared to the cost under the Excelsior PPA?

Response:

If Mesaba Unit 1 did not meet its proposed commercial operation date, Xcel Energy would utilize its own resources and available market resources to procure the capacity and energy necessary to meet its load obligations. Pursuant to our approved resource plan, the Minnesota Public Utilities Commission has determined that Xcel Energy does not need additional baseload capacity until 2015 and we do not anticipate the need to replace capacity that is in excess of our approved resource plan.

Response By:	Elizabeth Engelking
Title:	Manager, Resource Planning and Bidding
Date:	October 30, 2006

MCC Exhibit __ (BB Surrebuttal 3)

☐ **Non Public Document – Contains Trade Secret Data**
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☒ **Public Document**

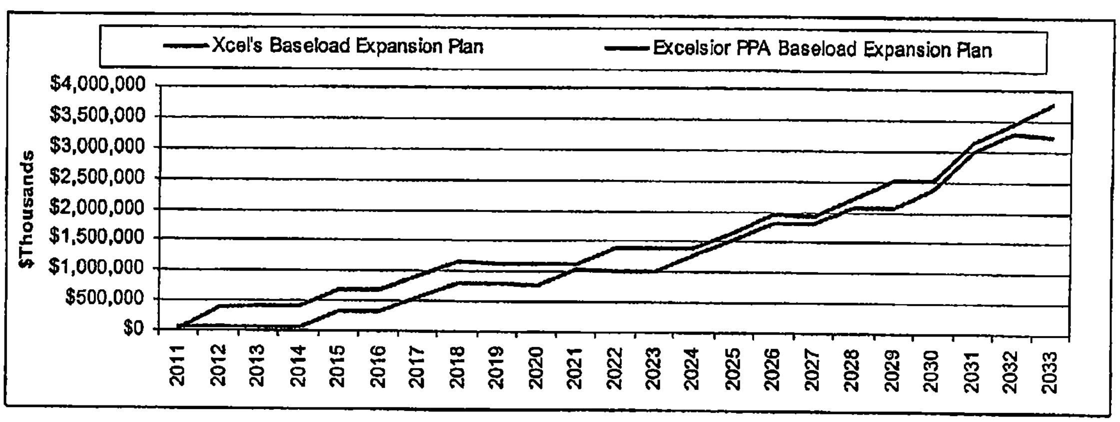
Xcel Energy
Docket No.: E6472/M-05-1993
Response To: MN Chamber of Commerce Information Request No. 21
Date Received: October 17, 2006

Question:

What is the cost of Xcel's own expansion of baseload generating facilities over the 25-year period proposed by Excelsior for its PPA?

Response:

Xcel Energy's analysis shows that its base load expansion plan is substantially less expensive than the expansion plan that includes the Excelsior PPA. Summing the total cost of baseload additions from 2011 to 2033, the last year of Xcel Energy's strategist model, the 2007 net present value of the increased costs caused by Excelsior is $2,126,666,000. The following chart illustrates the differences in baseload expansion costs.



Response By: Elizabeth Engelking

1957646v1

Title:	Manager, Resource Planning and Bidding
Date:	October 30, 2006

MCC Exhibit ____ (BB Surrebuttal 4)

Economic Impacts from Rate Increases to Non-DSI Federal Power Customers Resulting from Concessional Rates to the DSIs

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Moscow, Idaho 83843

Submitted to the Public Power Council,
Marilyn Showalter, Executive Director.
1500 NE Irving Street, Suite 200
Portland, Oregon 97232

May 31, 2006

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Executive Summary

Our charge in this study was to look at the consequences for the rest of the regional economy if non-DSI purchasers of wholesale power were required by the Bonneville Power Administration to pay higher electricity rates in order to fund DSI electric rates lower than the incremental cost of acquiring the electricity needed to serve that load. The magnitude of such a DSI rate subsidy is uncertain. It would depend on the quantity of electricity subsidized, and on the difference between the incremental acquisition price and the price at which the power is sold to the DSIs. In our analysis the annual subsidy is assumed to be $150 million.

Our modeling is based on an input-output model for the Pacific Northwest (PNW) region, including Oregon, Washington, Idaho and the western portion of Montana. Using this model as the starting point, we produced short-run and long-run model analyses.

Our short-run model assumed that the non-household sectors had a perfectly inelastic demand for electricity. The impact to business and industrial users was assumed to be a loss of owners' income, and the impact to government was assumed to be a reduction in payroll. Households, faced with this income loss and higher prices, were assumed to reduce consumption. This initial impact is assumed to propagate through the regional economy with further rounds of job losses and value added losses. The short-run model result is a total value added loss of $182.8 million per year and a total employment loss of 2,235 jobs throughout the regional economy.

Table ES1

Short-Run and Long-Run Employment and Value Added Effects of Higher Electric Rates to Non-DSI Electricity Users

	Direct	Indirect	Total
Short-Run			
Value Added ($ million per year)	-$77.4	-$105.4	-$182.8
Employment (# of jobs)	-287	-1,948	-2,235
Long-Run			
Value Added ($ million per year)	-$41.3	-$118.6	-$160.0
Employment (# of jobs)	-720	-2,103	-2,823

Our long-run model assumed somewhat more flexibility in responding to electricity price increases. Demands for output of the commercial and industrial sectors was assumed to have unitary elasticity – so while prices would increase somewhat in response to higher electricity prices, production levels would fall by the same amount, and total revenues would remain unchanged. The long-run model results show somewhat less value added loss per year, $160.0 million, and a bit more job loss, 2,823 jobs, than the short-run model.

We discuss possible reasons why the real-world flexibility that electricity users have in responding to higher prices might have caused our rather rigid models to under- or over-estimate the true value added and income effects. We conclude that there are arguments for both under- and over-estimation, and that our models probably take a reasonable middle road. We do note that as the size of the DSI rate subsidy gets larger, it takes larger electricity price increases to the non-DSU electricity users to balance BPA's budget. The higher price increases make it more likely that some firms will reduce their production levels or shut down. Thus at high subsidy levels, our models may underestimate the loss of employment and value added.

Our conclusion from our modeling is that if a DSI rate subsidy of $150 million is passed back to all non-DSI customers in the form of higher electric rates, the result would be a value added loss of $160 million to $180 million per year and an employment loss of at least 2,200 to 2,800 jobs. This potential significant loss of employment and value added from higher electricity prices to non-DSI consumers needs to be seriously weighed by policy-makers before any decision is made to provide rate subsidies to the DSIs.

One further conclusion should be noted. Our model did not disaggregate the effects of the price changes by region. However, if the model had allowed this level of detail, it would have shown that the effects of the DSI rate subsidy differ considerably between different parts of the PNW. The price increases were assumed to be borne by non-DSI electricity users all across the BPA service area. However, the job and value added benefits from the aluminum industry would be concentrated in the sub-regions near the smelters. The large parts of the BPA service area that are distant from smelters would bear significant costs from a DSI rate subsidy, but reap few benefits.

Introduction

The purpose of this project is to analyze the impact on other electricity consumers in the Northwest if the direct service industrial customers (DSIs) are supplied by Bonneville Power Administration (BPA) with up to 560 average megawatts (aMW) of power beginning in FY2011 at rates that are equivalent to BPA's priority firm rate, which is expected to be less than the incremental cost to BPA of acquiring that electricity. It is expected that such sales of power below the marginal cost of acquiring that power would result in a cost which would have to be met by rate increases to other electricity users in the BPA service area. The Public Power Council commissioned this study as input to Bonneville Power Administration discussions about this topic.

The PNW aluminum industry has faced serious financial difficulties in recent decades. International factors including globalization contributed first to weak world prices for aluminum metal. Increased electricity prices and electricity supply shortages in the PNW severely squeezed the industry, peaking in 2001.[1] More recently very high prices for alumina, the primary raw material (besides electricity) to aluminum production, have continued to plague the industry. Out of ten aluminum smelters in the region with a total potential demand of 3,150 aMW, only three of the lowest cost smelters are presently operating, with demand totaling about 300 aMW.

While BPA is not legally obligated to provide firm power contracts to the DSIs, it currently has agreed to provide up to 320 MW to Alcoa, up to 140 MW to Columbia Falls, up to 100 MW to Golden Northwest and 17 MW to Port Townsend Paper Company, for a total commitment of up to 577 MW for the years 2006 through 2010[2]. Presently these users are paying flat undelivered rates designated as "IP-TAC A and B" (Industrial Power, Targeted Adjustment Clause). The "A" rate is presently $30.70 per MWH and the "B" rate is $32.60 per MWH[3], including the effects of various surcharges levied on most of BPA's rates during the 2002-06 rate period.

Present electricity demand by the DSIs is substantially below the amounts that BPA has announced a willingness to sell. Table A1 shows that in 2005 BPA sold electricity valued at $82.5 million to the DSIs, which at the prices in the previous paragraph would have been 297 aMW. The table also shows that in 2006 BPA has contract obligations to sell 271 aMW to the DSIs. Sales in the first calendar quarter of 2006 totaled $21.3 million, or about 307 aMW[4].

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[1] Appendix A to the Council's 5th Power Plan contains a good summary of the status of the PNW aluminum industry, including forecasts of electricity demand. This document is available on the web at http://www.nwcouncil.org/energy/powerplan/plan/Appendix%20A%20(Demand%20Forecast).pdf Another good (although more dated) information source on the aluminum industry is the March 2001 report of the BPA Northwest Aluminum Industry Study Team http://www.bpa.gov/power/pl/aluminumstudy/ReviewSummary.pdf

[2] These quantity commitments come from an article in the Oregonian "BPA Fixes Contracts as 577 Megawatts" by Jonathan Brinkman, July 2, 2005, http://www.fwee.org/news/getStory?story=1390

[3] From BPA's posted average rates, found at http://www.bpa.gov/power/psp/rates/current.shtml

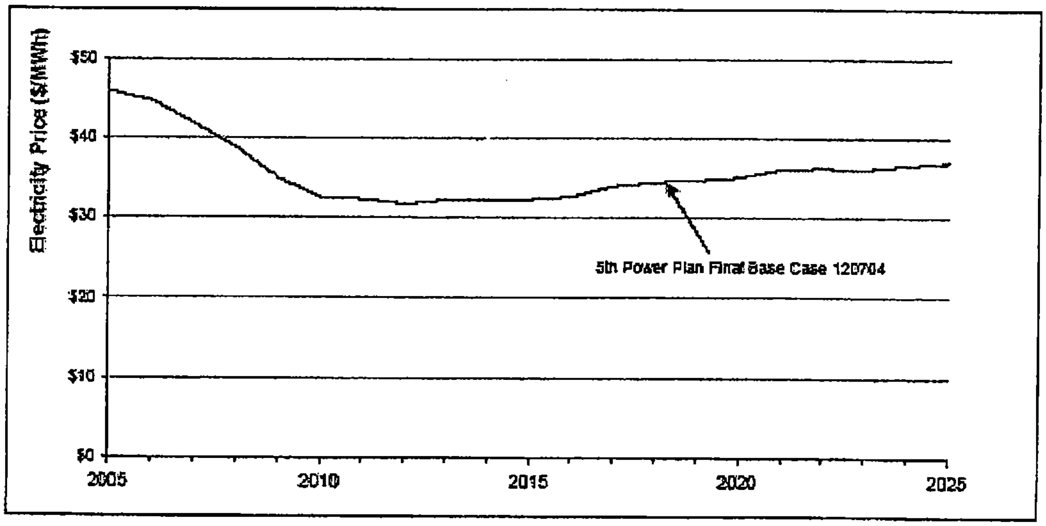
[4] From the BPA 2nd Quarter 2006 Financial Report http://www.bpa.gov/corporate/Finance/q_report/06/06-2qtrly.pdf

The Council's 5th Power Plan forecast for DSI demand in 2010 is 958 aMW, which implies considerable recovery from present conditions. Presently DSI demand is about 1/3 this level. Meeting the 958 aMW demand level would require some combination of electric costs lower than BPA's current rates, higher aluminum metal prices, or lower alumina prices.

The Possible Magnitude of the DSI Rate Subsidy

The magnitude of the possible DSI rate subsidy starting in 2011 is uncertain. As noted above, the quantity of the concessional DSI sales is very uncertain, although the 560 aMW current obligation to the aluminum industry would seem to be a reasonable starting point[5].

The dollar magnitude of the subsidy would also depend critically on the difference between the BPA priority firm rate and the incremental cost to BPA of acquiring that electricity. The Council's 5th Power Plan (Appendix C) presents the following forecast Mid Columbia electricity spot prices:



The Council forecast is based on assumptions that fuel prices (especially the price of natural gas) will decline from their highs in recent years. Under this assumption, spot market prices would decline to a marginal cost of generation of about $33 per MWh by 2011[6].

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[5] This is also the amount noted in Paul Norman's March 10, 2006 letter announcing the BPA study: http://www.bpa.gov/power/pl/regionaldialogue/03-30-2006_dsi_letter.pdf

[6] This study includes prices and dollar values at several points in time, for example historic power sales in 2004 and 2005 and electricity prices for 2006 and 2011. For simplicity in the short time we had available for the analysis, we have chosen to ignore the possible but uncertain effects of inflation. We have not attempted to inflate or deflate these figures to a common base time period.

Another measure of the future incremental cost that BPA might face to acquire the additional power it would need to serve these DSI loads comes from what the investor-owned utilities expect to pay for their future power purchases. PacifiCorp publishes its avoided-cost price (which it agrees to pay to buy power from Oregon cogeneration and other power producers of 10,000 KW or less). The current avoided cost figure for power delivered in 2011 is 6.54 cents per kWh on-peak and 4.57 cents off-peak,[7] [8] Given that 96 out of 168 hours in each week are considered on-peak, the weighted average cost of this power is $57.68 per MWh

$$(\$0.0654 * 96 / 156 + \$0.0457 * 72 / 168) * 1000 = \$57.68$$

The rate at which this power might be sold to the DSIs is also in question. Presently the DSIs pay rates averaging about $31.70 per MWh – somewhat above the present "shaped" firm power rate of $29.10 per aMW, and well above the current "flat" firm power rate of $25.80 per aMW. Since the DSI demand is essentially flat (meaning that it varies little over time) they will presumably argue for the $25.80 rate. Since that would result in the largest subsidy, we will use that as a limiting case in the analysis that follows.

Given these numbers, one can get an idea of the size of the possible DSI subsidy. Using the Council's forecast of a Mid Columbia spot price of about $33 in 2011 as the acquisition price, and $25.80 as the price at which the power would be sold to the DSIs, gives a difference of $7.20. Applying this to 560 aMW and 8,760 hours per year gives an annual DSI subsidy of:

$$(\$33.00 - \$25.80) * 560 * 8,760 = \$35,329,320$$

Alternatively, if PacifiCorp's recent avoided cost filing is a better predictor of the cost of acquiring this power, then the subsidy would be:

$$(\$57.68 - \$25.80) * 560 * 8,760 = \$156,378,755$$

Obviously, there is considerable uncertainty about both the quantity of electricity that might be subsidized, the cost that BPA would face in acquiring that power on the regional electricity market, and the price at which this power might be sold to the DSIs. In the analysis that follows, we will use $150 million as the assumed magnitude of the subsidy. We will also discuss how that assumption affects our results: how the results would change if the subsidy were less than, or more than, $150 million.

[7] From Pacific Power and Light Company Schedule 37, July 12, 2005, http://www.pacificorp.com/Regulatory_Rule_Schedule/Regulatory_Rule_Schedule55260.pdf

[8] It is possible that the Council's forecast is a "Mid-C Hub" price, whereas PacifiCorp's is "at the meter", which will be higher because it includes transmission losses from Mid-C to the retail meter: PacifiCorp is able to avoid both the purchase of energy at Mid-C and the major variable cost associated with transmission and distribution of energy to retail loads. In the short time available for our study we have not attempted to untangle these assumptions.

The Impacts of a DSI Rate Subsidy on Other Electricity Consumers

BPA is required by law to price its electricity and other services to cover its costs. If the DSIs are granted a rate that is less than the incremental cost of acquiring their block of power, then these added rates will have to be woven into the rates charged to other regional electricity users. One might characterize this as a "tax" on the other users.

Some of the other users are probably immune to this tax. The rates charged to US Bureau of Reclamation projects and a few other federal entities are based on long-term contracts, and are not likely to be affected. This leaves power sales to non-DSI and non-federal entities to absorb most of the tax. In practice this will be mostly the "public" power utilities – municipal utilities, the Rural Electric Associations (REAs) the Public (and People's) Utility Districts (PUDs), and the Municipals (MUNIs). Numbers provided by NPCC staff (Table A1) indicate that the publicly owned utilities account for about 44% of total non-DSI electricity sales volume in the Pacific Northwest, and about 82% of BPA's non-DSI electricity sales revenues.

BPA's non-DSI power sales revenues totaled $2,107 million in 2005[9]. A $150 million DSI rate subsidy, if passed back equally as a tax to all these other users would amount to a 7.1% increase in rates:

$150 million / $2,107 million = 7.1 %

If it were passed back only to the publicly owned utilities (excluding the federal entities with long-term contracts and the investor owned utilities who now buy mostly non-firm power from BPA) from whom BPA received $1,717 million in revenue in 2005, the resulting rate increase would be somewhat less than 8.7%.

$150 million / $1,717 million = 8.7%

The "somewhat less" is because PGE and PacifiCorp both have firm power purchase agreements with BPA (although PGE's is going to expire fairly soon). PacifiCorp's contract rate is tied to BPA's average system cost, so presumably would increase if BPA subsidized the DSIs, reducing the amount that would need to be passed to the publicly owned utilities.

If the DSI rate subsidies are less than the $150 million assumed here, the required rate increases for everybody else would be proportionately smaller. However this works out though, we are talking about significant rate increases to non-DSI customers. These rate increases would be large enough that we would expect them to have real, measurable impacts on the non-DSI sectors of the regional economy.

[9] The revenue numbers come from page 37 of the BPA 2005 Annual Report, http://www.bpa.gov/corporate/Finance/A_Report/05/AR2005.pdf

Estimating the Economic Impacts of Rate Increases for Non-DSI Customers

Economic Modeling Specialists, Inc. (EMSI) builds regional Input-Output models for use in estimating economic impacts of alternative scenarios or policies.[10] For this study EMSI built a 468 sector model of the economies of Washington, Oregon, Idaho and Western Montana (the "Northwest"). This model region closely approximates the region within which the BPA service is contained.

We use this model to develop two alternative ways of looking at the impact of these electric rate increases on BPA non-DSI customers. We characterize these applications as a short-run model and a long-run model

The Short-Run Model

The short-run is characterized as a time period short enough so that capital assets of the electricity consuming business or household are fixed. In practice we tend to think of the short-run as measured in months or perhaps a year or so. The time period is too short for businesses to invest in new more energy efficient machinery or alternative technologies, and too short for households to buy new appliances or switch heating systems.

For modeling simplicity our short-run model adopts a rather extreme interpretation of what can be done in the short-run. The model assumes that the quantity of electricity demanded by all sectors except households is unchanged in the face of the expected price increases. In the language of economists, our short-run model assumes that non-household electricity demand is perfectly inelastic – or that the price elasticity[11] of demand is zero. Using this zero elasticity assumption means that business and industrial electricity users continue to use the same amount of electricity and continue to operate at the same level and produce the same output which they sell for the same revenue[12]. Because they have to pay more for their electricity purchases, this reduces their owners' income (measured as a change in value added[13]). Since the government

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[10] See the "Appendix on the EMSI IO Model" at the end of this report.

[11] Elasticity is defined as the percent change in quantity of electricity demanded for a one percent change in price. If elasticity were -0.2, for example, then a 1% increase in price would result in a 0.2% decrease in quantity demanded.

[12] One of the reasons why we adopted the modeling assumption of perfectly inelastic demand is that this assumption is consistent with the Input-Output model assumption of a fixed (Leontief) input mix. That is, the I-O model assumes that industries do not change their mix of inputs in response to price changes.

[13] Value added is defined as labor income (equal to the sum of wages, salaries and proprietors' incomes) plus a collection of non-labor or "owners' incomes," including mainly profits and rents. For our short-run analysis, we assume that only owner's incomes, and wages in the case of government sectors, change in response to the electricity price increase.

sector does not have "owners" to absorb the effect of higher electricity prices, we assume that they respond by reducing payrolls[14].

Households are hit by the electricity price increase in three ways. First, the loss of value added in the business and industrial sectors means that this lost owners' income will result in less consumption spending by owners' households. Second, the loss of government payroll reduces the income and consumption spending of the households of government workers. Third, all households will have to pay more for the electricity they consume, effectively reducing their "real" income. With reduced incomes and higher electricity prices, households will have to reduce their consumption of all items, including electricity. The initial reduced consumption spending will be multiplied as it works its way through the rest of the economy, producing further rounds of value added and employment losses.

We use our short-run regional model to track the economic and employment effects from the $150 million rate increase to non-DSI customers. The model allows us to track the effects by sector of the economy. Table 1 provides current value added and job totals for the Northwest Economy – these serve as backdrop for computing relative impacts. The short-run model results themselves are shown in Tables 2 and 3.

Table 1 shows the baseline 2005 value added and employment, aggregated to 20 sectors. There is a total of $429 billion in value added for the Northwest region (modeled as Washington, Oregon, Idaho and western Montana).[15] The jobs total for the region is 6.93 million.

Table 2 shows how the $150 million per year increase in electricity prices would affect value added in the region, under our assumption of a perfectly inelastic demand for non-household electricity. The first set of columns shows the direct value added effect – the loss of value added directly due to owners' income loss in the commercial and industrial sectors, and the loss of payroll in the government sector. Since about half of the electricity is consumed by these sectors, the direct value added effect of $77.4 million is about half of the $150 million total rate increase. As this initial impact works its way through the economy, along with the direct household consumption impact of higher electricity prices, it spreads out more evenly across the sectors, especially those sectors that play a large role in household consumption, causing an additional $105.4 million loss of value added. The total impact, direct plus indirect value added, is $182.8 million per year.

Table 3 shows the impacts on jobs. The initial direct loss of 287 jobs is restricted to the government sector, reflecting our assumption that government responds to the electricity price increase by reducing payroll. The business sectors were assumed to keep payrolls unchanged, but absorb the price change in reduced owners' incomes. The indirect job loss as the impact

[14] Assuming that government responds by increasing taxes would produce nearly identical total employment and value added results, but with impacts shown for government in Tables 2 and 3 spread instead across the other non-government sectors of the model.

[15] Value added at the state level is sometimes referred to as "Gross State Product," or "GSP," and the values reported in Table 2 are generally consistent with published GSP estimates (e.g., www.bea.gov).

Table 1
Baseline 2005 Value Added and Employment
BPA Four-State Service Area

NAICS Code	Description	Value Added ($1,000)	% total	Jobs	% total
110000	Agriculture	$ 12,523,062	2.9%	288,937	4.2%
210000	Mining	$ 970,983	0.2%	13,594	0.2%
220000	Utilities	$ 6,170,056	1.4%	11,853	0.2%
230000	Construction	$ 22,114,500	5.2%	440,660	6.4%
3A0000	Manufacturing: nondurable goods	$ 16,279,910	3.8%	156,234	2.3%
3B0000	Manufacturing: durable goods	$ 42,748,611	9.9%	407,647	5.9%
420000	Trade	$ 54,552,500	12.7%	1,019,240	14.7%
480000	Transportation	$ 13,383,122	3.1%	219,511	3.2%
510000	Information	$ 30,185,826	7.0%	160,218	2.3%
520000	Finance and insurance	$ 26,993,770	6.3%	268,353	3.9%
530000	Real estate and leasing	$ 33,322,234	7.8%	273,325	3.9%
540000	Professional, Scientific, and Technical Services	$ 28,722,225	6.7%	429,010	6.2%
550000	Management of companies and enterprises	$ 6,861,370	1.6%	70,978	1.0%
560000	Administrative, support, waste mgt and remediation serv	$ 14,645,361	3.4%	362,637	5.2%
610000	Educational services	$ 2,901,989	0.7%	118,962	1.7%
620000	Health care and social assistance	$ 32,464,069	7.6%	675,477	9.7%
710000	Arts, entertainment and recreation	$ 4,160,522	1.0%	150,155	2.2%
720000	Accommodation and food services	$ 12,826,040	3.0%	455,011	6.6%
810000	Other services	$ 10,928,254	2.5%	364,701	5.3%
	Government	$ 56,571,074	13.2%	1,050,238	15.1%
	Total	$ 429,325,477	100.0%	6,936,738	100.0%

Table 2
Short-Run Value Added Impact of Electricity Rate Increase on Non-DSI Users
BPA Four-State Service Area

NAICS Code	Description	Direct ($1,000)	% total Direct	Indirect ($1,000)	% total indirect	Total ($1,000)	% total Total
110000	Agriculture	$ (2,715)	3.5%	$ (1,698)	1.6%	$ (4,413)	2.4%
210000	Mining	$ (640)	0.8%	$ (80)	0.1%	$ (721)	0.4%
220000	Utilities	$ (201)	0.3%	$ (1,980)	1.9%	$ (2,181)	1.2%
230000	Construction	$ (1,788)	2.3%	$ (1,356)	1.3%	$ (3,144)	1.7%
3A0000	Manufacturing: nondurable goods	$ (8,831)	11.4%	$ (4,275)	4.1%	$ (13,106)	7.2%
3B0000	Manufacturing: durable goods	$ (8,983)	11.6%	$ (2,619)	2.5%	$ (11,602)	6.3%
420000	Trade	$ (10,062)	13.0%	$ (21,142)	20.1%	$ (31,204)	17.1%
480000	Transportation	$ (1,334)	1.7%	$ (3,078)	2.9%	$ (4,412)	2.4%
510000	Information	$ (1,613)	2.1%	$ (5,135)	4.9%	$ (6,748)	3.7%
520000	Finance and insurance	$ (1,191)	1.5%	$ (8,656)	8.2%	$ (9,847)	5.4%
530000	Real estate and leasing	$ (10,266)	13.3%	$ (10,373)	9.8%	$ (20,639)	11.3%
540000	Professional, Scientific, and Technical Services	$ (1,629)	2.1%	$ (4,631)	4.4%	$ (6,260)	3.4%
550000	Management of companies and enterprises	$ (1,223)	1.6%	$ (1,544)	1.5%	$ (2,767)	1.5%
560000	Administrative, support, waste mgt and remediation serv	$ (1,641)	2.1%	$ (3,131)	3.0%	$ (4,772)	2.6%
610000	Educational services	$ (388)	0.5%	$ (836)	0.8%	$ (1,224)	0.7%
620000	Health care and social assistance	$ (3,425)	4.4%	$ (16,032)	15.2%	$ (19,457)	10.6%
710000	Arts, entertainment and recreation	$ (983)	1.3%	$ (1,734)	1.6%	$ (2,717)	1.5%
720000	Accommodation and food services	$ (4,175)	5.4%	$ (6,002)	5.7%	$ (10,177)	5.6%
810000	Other services	$ (1,649)	2.1%	$ (4,091)	3.9%	$ (5,740)	3.1%
	Government	$ (14,661)	18.9%	$ (7,020)	6.7%	$ (21,680)	11.9%
	Total	$ (77,397)	100.0%	$ (105,415)	100.0%	$(182,812)	100.0%

Table 3
Short-Run Jobs Impact of Electricity Rate Increase on Non-DSI Users
BPA Four-State Service Area

NAICS Code	Description	Direct	% total direct	Indirect	% total indirect	Total	% total Total
110000	Agriculture	-	0.0%	(47)	2.4%	(47)	2.1%
210000	Mining	-	0.0%	(1)	0.1%	(1)	0.1%
220000	Utilities	-	0.0%	(4)	0.2%	(4)	0.2%
230000	Construction	-	0.0%	(27)	1.4%	(27)	1.2%
3A0000	Manufacturing: nondurable goods	-	0.0%	(44)	2.2%	(44)	2.0%
3B0000	Manufacturing: durable goods	-	0.0%	(34)	1.8%	(34)	1.5%
420000	Trade	-	0.0%	(442)	22.7%	(442)	19.8%
480000	Transportation	-	0.0%	(53)	2.7%	(53)	2.4%
510000	Information	-	0.0%	(32)	1.6%	(32)	1.4%
520000	Finance and insurance	-	0.0%	(83)	4.2%	(83)	3.7%
530000	Real estate and leasing	-	0.0%	(93)	4.8%	(93)	4.2%
540000	Professional, Scientific, and Technical Services	-	0.0%	(74)	3.8%	(74)	3.3%
550000	Management of companies and enterprises	-	0.0%	(16)	0.8%	(16)	0.7%
560000	Administrative, support, waste mgt and remediation serv	-	0.0%	(83)	4.3%	(83)	3.7%
610000	Educational services	-	0.0%	(32)	1.6%	(32)	1.4%
620000	Health care and social assistance	-	0.0%	(330)	16.9%	(330)	14.8%
710000	Arts, entertainment and recreation	-	0.0%	(53)	2.7%	(53)	2.4%
720000	Accommodation and food services	-	0.0%	(216)	11.1%	(216)	9.7%
810000	Other services	-	0.0%	(142)	7.3%	(142)	6.4%
	Government	(287)	100.0%	(143)	7.4%	(430)	19.3%
	Total	(287)	100.0%	(1,948)	100.0%	(2,235)	100.0%

spreads out through the rest of the economy produces a further job loss of 1,948 jobs. The total short-run employment loss caused by the electricity price increase is estimated to be 2,235 jobs.

Our short-run model assumed that electricity consumers have no ability to adjust their electricity use in the time frame of a few months to a year. We know that is not really true – there are always some opportunities for both businesses and households to reduce power usage in response to higher prices. There are opportunities to turn down thermostats and turn out lights, in a few cases existing hardware may be amenable to fuel switching, but in the short-run these opportunities are limited relative to the longer-run, which we will discuss below. In the short-run, and for price increases of the magnitude used here, we would not expect to see major changes in output levels by businesses and manufacturing firms in the region, and we would expect few firms to close in the short-run because they can't pay the power costs.

Appendix Tables A2 and A3 include estimates of short-run elasticities from various studies, including the elasticity estimates embedded in the Energy Information Agency energy sector model. Clearly, the electricity demand estimates are quite diverse, depending on the assumptions, data and estimation methods used. The one-year short-run electricity demand elasticity estimates from Table A3 look quite plausible at -0.20 for residential and -0.10 for commercial electricity consumers.

Using the 7 to 8% electricity price increase to BPA non-DSI electricity consumers corresponding to a $150 million DSI rate subsidy would mean that customers would cut their electricity consumption by only 1 to 2%. This suggests that our short-run model assumption of perfectly inelastic demand response is probably not a bad assumption.

To the extent that some short-run demand response does occur, the effect can be both positive and negative. If electricity users are moved to adopt conservation measures because conservation is cheaper than paying the higher electricity price, then this reduces the regional effects of the price increase below our model estimates. If businesses are moved to make some cuts in output by higher power costs, this would cut profits, and increase the regional effects of the price increase above our model estimates. Our short-run model takes a middle route between these two offsetting paths.

The Long-Run Model

Over a longer time period, there will be opportunities for electricity users to adapt to higher prices. They may implement conservation; switch fuels, or implement other changes that reduce electricity use. In the extreme, businesses may be driven to drastically reduce production levels, suspend production, or even go out of business. Households face a similar range of options in the long-run. Comprehensively modeling all this would require information on the characteristics and adjustment alternatives facing each sector that are beyond the scope and the 2 ½ week time frame of this study. What we do is to build a model that allows for some of the flexible response we expect to occur. Our long-run model results are shown in tables 4 and 5.

Table 4
Long-Run Value Added Impact of Electricity Rate Increase on Non-DSI Users
BPA Four-State Service Area

NAICS Code	Description	Direct ($1,000)	% total direct	Indirect ($1,000)	% total indirect	Total ($1,000)	% total Total
110000	Agriculture	$ (968)	2.3%	$ (3,171)	2.7%	$ (4,139)	2.6%
210000	Mining	$ (333)	0.8%	$ (221)	0.2%	$ (554)	0.3%
220000	Utilities	$ (111)	0.3%	$ (2,360)	2.0%	$ (2,471)	1.5%
230000	Construction	$ (803)	1.9%	$ (2,758)	2.3%	$ (3,561)	2.2%
3A0000	Manufacturing: nondurable goods	$ (2,569)	6.2%	$ (4,978)	4.2%	$ (7,547)	4.7%
3B0000	Manufacturing: durable goods	$ (3,447)	8.3%	$ (4,253)	3.6%	$ (7,700)	4.8%
420000	Trade	$ (6,085)	14.7%	$ (21,521)	18.1%	$ (27,607)	17.3%
480000	Transportation	$ (725)	1.8%	$ (3,889)	3.3%	$ (4,614)	2.9%
510000	Information	$ (897)	2.2%	$ (5,819)	4.9%	$ (6,716)	4.2%
520000	Finance and insurance	$ (706)	1.7%	$ (8,713)	7.3%	$ (9,419)	5.9%
530000	Real estate and leasing	$ (7,126)	17.2%	$ (12,341)	10.4%	$ (19,468)	12.2%
540000	Professional, Scientific, and Technical Services	$ (1,091)	2.6%	$ (6,219)	5.2%	$ (7,311)	4.6%
550000	Management of companies and enterprises	$ (863)	2.1%	$ (2,217)	1.9%	$ (3,080)	1.9%
560000	Administrative, support, waste mgt and remediation serv	$ (923)	2.2%	$ (4,352)	3.7%	$ (5,276)	3.3%
610000	Educational services	$ (221)	0.5%	$ (774)	0.7%	$ (995)	0.6%
620000	Health care and social assistance	$ (2,052)	5.0%	$ (14,185)	12.0%	$ (16,237)	10.2%
710000	Arts, entertainment and recreation	$ (588)	1.4%	$ (1,628)	1.4%	$ (2,216)	1.4%
720000	Accommodation and food services	$ (2,229)	5.4%	$ (5,654)	4.8%	$ (7,883)	4.9%
810000	Other services	$ (915)	2.2%	$ (4,030)	3.4%	$ (4,945)	3.1%
	Government	$ (8,674)	21.0%	$ (9,556)	8.1%	$ (18,230)	11.4%
	Total	$ (41,327)	100.0%	$ (118,639)	100.0%	$(159,966)	100.0%

Table 5
Long-Run Jobs Impact of Electricity Rate Increase on Non-DSI Users
BPA Four-State Service Area

NAICS Code	Description	Direct	% total direct	Indirect	% total indirect	Total	% total Total
110000	Agriculture	(28)	3.9%	(74)	3.5%	(102)	3.6%
210000	Mining	(4)	0.6%	(3)	0.2%	(8)	0.3%
220000	Utilities	(0)	0.1%	(5)	0.2%	(5)	0.2%
230000	Construction	(16)	2.2%	(55)	2.6%	(71)	2.5%
3A0000	Manufacturing: nondurable goods	(20)	2.8%	(49)	2.3%	(70)	2.5%
3B0000	Manufacturing: durable goods	(35)	4.9%	(53)	2.5%	(88)	3.1%
420000	Trade	(134)	18.6%	(429)	20.4%	(563)	19.9%
480000	Transportation	(11)	1.6%	(67)	3.2%	(78)	2.8%
510000	Information	(6)	0.8%	(36)	1.7%	(42)	1.5%
520000	Finance and insurance	(8)	1.2%	(83)	3.9%	(91)	3.2%
530000	Real estate and leasing	(65)	9.0%	(109)	5.2%	(174)	6.2%
540000	Professional, Scientific, and Technical Services	(16)	2.2%	(99)	4.7%	(115)	4.1%
550000	Management of companies and enterprises	(9)	1.2%	(23)	1.1%	(32)	1.1%
560000	Administrative, support, waste mgt and remediation serv	(13)	1.8%	(114)	5.4%	(127)	4.5%
610000	Educational services	(9)	1.3%	(30)	1.4%	(39)	1.4%
620000	Health care and social assistance	(51)	7.1%	(293)	13.9%	(344)	12.2%
710000	Arts, entertainment and recreation	(19)	2.7%	(51)	2.4%	(70)	2.5%
720000	Accommodation and food services	(79)	10.9%	(202)	9.6%	(281)	10.0%
810000	Other services	(27)	3.7%	(134)	6.4%	(161)	5.7%
	Government	(170)	23.5%	(195)	9.3%	(365)	12.9%
	Total	(720)	100.0%	(2,103)	100.0%	(2,823)	100.0%

Our model assumes a unitary demand elasticity for the products produced in the region (that is, if the price of these products increases, the quantity demanded will fall by the same percentage, leaving total revenues unchanged). We also keep the usual assumption of input-output analysis that physical production inputs change in constant proportion. Now, value added in the production sectors will fall, both because businesses and industries pay more for electricity, and because they will be producing less output. Again, the resulting losses of value added in the production sectors and the real income effects of higher prices for electricity to the household sectors will be translated into impacts on employment and income by sector.

Our long-run model results in tables 4 and 5 are actually not that much different from our short-run model results shown in tables 2 and 3. The comparison is summarized in Table 6. The total impacts on value added and the total impacts on jobs are quite similarly distributed across the sectors. The $160.0 million total annual impact on value added is somewhat less than the $182.8 million annual impact estimated by the short-run model. The 2,823 long-run jobs impact is somewhat more than the 2,235 jobs found by the short-run model.

Table 6

Short-Run and Long-Run Employment and Value Added Effects of Higher Electric Rates to Non-DSI Electricity Users

	Direct	Indirect	Total
Short-Run			
Value Added ($ million per year)	-77.4	-105.4	-182.8
Employment (# of jobs)	-287	-1,948	-2,235
Long-Run			
Value Added ($ million per year)	-41.3	-118.6	-160.0
Employment (# of jobs)	-720	-2,103	-2,823

There is no a priori reason why the long run economic impact of an electricity price increase should be higher or lower than the economic impact in the short run. The long-run allows time for electricity consumers to take steps to adjust to the higher prices in ways that would reduce their economic impact. On the other hand, the long run may give some marginal users time to face the reality that higher electricity prices have made them no longer competitive in the marketplace, and to perhaps move from the region or exit from production, which would increase the economic impact.

However it is instructive to compare short-run Tables 2 and 3 and long-run Tables 4 and 5. In particular, the short-run value-added impact ($182.8 million) is larger than the long-run value-added impact ($160 million). In contrast, the impacts on jobs are just the opposite. The short-run model estimates the employment loss as 2,235, while the long-run model estimate is higher at 2,823. Recall that in the short-run higher electricity prices are covered by reduced owners' incomes, while holding direct output levels constant: in the short-run, a relatively large portion of the overall value added impact is reduced owners' incomes, with no corresponding effect on direct employment. In the long-run, owners move to restore profit margins by raising output prices: the response is a reduction in the level of output, with a loss of employee wages. The long-run thus results in a greater job loss than the short-run because it allows for this output change. At the same time, value added impacts decline because profit margins are restored: with time to adjust, a considerable portion of the burden of the electricity price increase is shifted from business owners to employees.

In the long-run, consumers have many options for responding to and adjusting to higher electricity prices. Tables A-2 and A-3 illustrate the wide range of estimates of long-run elasticity of electricity demand with respect to electricity price. The elasticity estimates range from about -0.5 to -2.0 or even more. This means that a 1% increase in electricity price would cause electricity demand to drop by somewhere between 0.5% and 2.0%. This kind of response would be expected from both commercial and household electricity users. Table A-3 suggests that commercial sectors for which electricity is a "core end use" (e.g. computer server farms, pulp and paper mills, or other industries which use electricity for process heat) would be even more responsive to price than other electricity users, especially if they respond by exiting from production or from the region.

Contrary to the standard input-output model assumption, that production inputs are used in fixed proportions, which we adhered to in our model, electricity users actually have many opportunities to change the input mix they use. Faced with higher electricity prices, electricity users may substitute capital investment for electricity – we normally call this "conservation". Businesses may invest in new energy efficient machinery, better insulation, and energy saving process control devices. Households may invest in new energy efficient appliances, compact fluorescent lighting, and automated lighting and heating control systems, or just do a little better in turning out lights in unoccupied rooms. If the costs of these conservation measures are exceeded by the savings in electricity costs then this investment reduces the total economic impact of the electricity price increase.

The flexibility to change input mix goes well beyond just conservation. Electricity is one of several alternative energy sources. Fuel substitution – substituting one energy source for another -- is often a possible response to price changes. Both commercial and residential space heating can be powered by electricity, natural gas, or fuel oil, whichever is cheaper. Some industries require process heat, which could be supplied by natural gas, fuel oil or electricity, whichever is cheaper. Of course the changeovers can be expensive, so this is usually a long-run proposition. However, if the costs of these fuel substitution measures are exceeded by the savings in electricity costs then this reduces the total economic impact of the electricity price increase.

In some cases there may be businesses which use lots of electricity but find little scope for electricity conservation or fuel substitution. In these instances higher fuel prices simply translate into higher costs and reduced competitiveness of that business. Such businesses may be able to survive for a time paying higher electricity costs, living on the depreciation of the business assets, and surviving on reduced owner's income. However, that is not a viable long-run strategy. In the long-run such a business will face the reality that their capital has depreciated and replacing it with new investment is not justified. In the long-run the owners of such businesses will find better things to do than survive on reduced owners' incomes. One example of such an industry might be electric pump irrigation. Irrigators who pump from very deep wells, or lift water to fields a considerable height above a river may have little they can do to mitigate higher prices for pumping electricity. Another example might be a pulp and paper mill that uses large amounts of electricity for mechanical power. In the long-run businesses such as these can be expected to cut back production, leave the region, or go out of business if electricity prices increase above some threshold. To the extent that this happens, the economic impact of higher electricity prices on jobs and value added will be higher than estimated by our long-run model.

We have given reasons why the adjustment opportunities actually available to electricity users might result in economic impacts somewhat above or below what we estimated with our somewhat rigid long-run model, and why the long run impacts might be less than or more than the short-run impacts. We view our models as taking an intermediate road between these possibilities, unless the subsidy and the consequent rate increase is at the upper end of the possible range, in which case our model may underestimate the value added and jobs impact.

Our bottom line is that we believe that the economic impact of a $150 million rate subsidy for the DSIs would be a decrease in the range of at least $160 to $180 million in annual regional value added and a decrease in the range of at least 2,200 to 2,800 jobs throughout the regional economy.

What if the subsidy is less than $150 million?

We indicated earlier that the $150 million rate subsidy was a very uncertain number. The $150 million is perhaps close to an upper bound, and the actual number might be $100 million -- or $50 million.

To actually empirically estimate the impacts of these alternative rate subsidy levels would require some quite sophisticated modeling (similar to what the Council did for the aluminum industry in their 5th Power Plan) which was beyond the data we had and the time we had available to do this study.

However, we can say what kind of response pattern we would expect. We would expect the severity of the economic impacts to escalate with the increased size of the subsidy, and this effect will be greater for the more electricity intensive sectors of the economy. For small electricity rate increases, users face a range of adjustment possibilities, such as conservation and fuel switching, which can mitigate the economic impacts. For larger price increases the easy adjustment opportunities will be typically exhausted, and the remaining ones more expensive.

For the electricity intensive industries with few opportunities to adjust to higher prices, when prices increase above some threshold the likely response is to go out of business or go bankrupt. Thus at high subsidy levels to the DSIs, and the resulting high rate increases to all other users, loss of employment and loss of value added may be even higher than estimated by our model.

Of course, our short-run and long-run models assumed that inputs were used in fixed proportions and did not actually allow for all these adjustment possibilities. Thus in a formal sense, if one were to use our models to estimate the impacts of smaller subsidies, the impacts would be proportional as shown in table 7.

It is still useful to keep in mind that in the real world these impacts would escalate with the larger subsidy, and that at higher subsidy and rate increase levels our model may underestimate the impacts.

Table 7

Employment and Value Added Effects of Higher Electric Rates to Non-DSI Electricity Users, at Various Subsidy Sizes

	Size of Subsidy to DSIs		
	$50 million	$100 million	$150 million
Short-Run			
Value Added ($ million)	-$60.9	-$121.9	-$182.8
Employment (# of jobs)	-745	-1,490	-2,235
Long-Run			
Value Added ($ million)	-$53.3	-$106.6	-$160.0
Employment (# of jobs)	-941	-1,882	-2,823

Conclusions

Our conclusion from our modeling is that if a DSI rate subsidy of $150 million is passed back to all non-DSI customers in the form of higher electric rates, the result would be a value added loss of $160 million to $180 million per year and an employment loss of at least 2,200 to 2,800 jobs. This potential significant loss of employment and value added from higher electricity prices to non-DSI consumers needs to be seriously weighed by policy-makers before any decision is made to provide rate subsidies to the DSIs.

One further conclusion should be noted. Our model did not disaggregate the effects of the price changes by region. However, if the model had allowed this level of detail, it would have shown that the effects of the DSI rate subsidy differ considerably between different parts of the PNW. The price increases were assumed to be borne by non-DSI electricity users all across the BPA service area. However, the job and value added benefits from the aluminum industry would be concentrated in the sub-regions near the smelters. The large parts of the BPA service area that are distant from smelters would bear significant costs from a DSI rate subsidy, but reap few benefits.

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Appendix A: Data

Table A1: Basic Data for Public Power Council Study

	Item	Source	Year	Units	Total	Residential	Commercial	Industrial Non-DSI	DSI	Irrigation	Other
1	Total Regional Electricity Demand	NPCC 5th Power Plan	2006	average MW	19,621	7,340	5,509	4997	958	631	186
			2011	average MW	20,917	7,789	5,835	5498	958	644	193

	Item	Source	Year	Units	Total	DSI	Public Entities	Federal & Other	Investor Owned	Exports
2	Total Regional Firm Energy Load	BPA 2004 PNW Loads & Resources Study	2006	average MW	21,706	296	8,531	457	11,025	1,397

	Item	Source	Year	Units	Total	DSI	Public Owned	USBR	Federal Agency
3	BPA Contract Load Obligations, PNW Region	BPA 2004 PNW Loads & Resources Study	2006	average MW	7,019	271	6,481	149	118
			2011	average MW	7,450	0	7,155	149	146

	Item	Source	Year	Units	Commercial	Residential	DSI Firm	Non DSI Firm	Irrigation	Other	Total Firm Sales	Total Non-DSI Sales
4	Total Annual Sales to End-Use Customers (Not Weather Adjusted)											
	Total	NPCC Staff	2004	average MW	5,547	6,685	311	3654	713	178	17,088	16,777
	Public Customer Pool	NPCC Staff	2004	average MW	2,169	2,918	311	1819	369	140	7,726	7,415
	Public as % of Total	Computed	2004	percent	39.1%	43.6%	100.0%	49.8%	51.8%	78.7%	45.2%	44.2%

	Item	Source	Year	Units	Total	DSI	Non-DSI	Public Owned	Investor owned
5	BPA Sales Within the PNW Region	BPA 2005 Annual Report	2005	$ thousands	2,190,028	82,454	2,107,574	1,717,063	390,511

	Item	Source	Residential	Commercial	Irrigation
6	Long-Run Elasticity for Electricity Demand	NPCC Staff	-0.4	-0.53	-0.24

	Item	Source	Period	Units	Shaped	Flat
7	BPA Priority Firm Wholesale Rate (undelivered)	BPA	4/1/06 to 9/30/06	cents/kWh	2.91	2.58

Table A2. Summary of Ranges of Residential and Commercial Elasticities From Dahl (1993)

Survey Source	Fuel	Data Type	Model Class	Short Run	Intermediate Run	Long Run
Residential Sector						
Taylor (1977)	Electricity	Grouped	Grouped	-0.07 to -0.61	-0.34 to -1.00	-0.01 to -1.66
	Natural Gas	Aggregate		0.00 to -0.16		0.00 to -3.00
Bohi (1981)	Electricity	Aggregate	Static	-0.00 to -0.45		-0.40 to -1.53
	Electricity	Aggregate	Dynamic	0.49		-0.44 to -1.09
	Electricity	Aggregate	Structural	-0.18		0.00 to -1.20
	Electricity	Aggregate	Other	-0.10 to -0.54		-0.72 to -2.10
	Electricity	Household	Dynamic	-0.16		-0.45
	Electricity	Household	Static	-0.14		-0.7
	Electricity	Household	Structural	-0.25		-0.66
	Natural Gas	Aggregate	Static			-1.54 to -2.42
	Natural Gas	Aggregate	Dynamic	-0.15 to -0.50		-0.40 to -1.02
	Natural Gas	Aggregate	Structural	-0.50		-2.00
	Natural Gas	Household	Dynamic	-0.20		-0.57
	Natural Gas	Household	Static			-0.17 to -0.45
(1984)	Electricity	Aggregate	Static		0.00 to -1.57	-0.10 to -0.52
	Electricity	Aggregate	Dynamic	0.00 to -0.55		-0.26 to -2.50
	Electricity	Household	Structural	-0.20 to -0.76		
	Electricity	Household	Static		-0.55 to -0.71	-0.05 to -0.71
	Electricity	Household	Structural	0.67		-1.40 to -1.51
	Natural Gas	Aggregate	Dynamic	-0.20 to -0.35		-2.79 to -3.44
	Natural Gas	Aggregate	Dynamic	-0.03 to -0.05		0.55
	Natural Gas	Household	Static			0.60
Surveys	Fuel Oil	Grouped	Grouped	0.00 to -0.70		0.00 to -1.50
Dahl (1993) New Studies	Electricity	Aggregate	Grouped	-0.57 to -0.60	-0.11 to -1.11	-0.77 to -2.20
	Electricity	Household	Grouped	-0.02 to -0.97	-0.05 to -0.97	-0.30 to -1.40
	Natural Gas	Aggregate	Grouped	0.35	1.06 to -2.41	1.56 to -3.44
	Natural Gas	Household	Grouped	0.00	-0.06 to -1.00	-1.09 to -1.49
	Fuel Oil	Aggregate	Grouped	-0.10 to -0.59	-0.77 to -1.22	-1.05 to -3.5
	Fuel Oil	Household	Grouped	-0.10 to -0.19	-1.09 to -1.56	-0.62 to -0.67
Commercial Sector						
Taylor (1977)	Electricity	Aggregate	Grouped	-0.24 to -0.54		-0.05 to -1.22
	Natural Gas	Aggregate		-0.30		-1.45
Bohi (1981)	Electricity	Aggregate	Dynamic	-0.17 to -1.10		-0.56 to -1.60
	Natural Gas	Disaggregate	Static			-1.04
(1984)	Electricity	Disaggregate	Grouped		0.00 to -4.56	0.00 to -1.05
	Natural Gas	Aggregate	Dynamic	0.00 to -0.37		0.00 to -2.27
Surveys	Fuel Oil	Grouped	Grouped	-0.30 to -0.61		-0.55 to -0.70
Dahl (1993) New Studies	Electricity	Aggregate	Grouped	0.00 to -0.02	-0.59 to -0.90	0.36 to -4.74
	Natural Gas	Aggregate	Grouped	-0.16 to -0.31	1.92 to -2.60	0.06 to -2.27
	Fuel Oil	Aggregate	Grouped	-0.07 to -0.19	-0.30	-0.40 to -3.50

Source: Quoted in Steven H. Wade, Price Responsiveness in the NEMS Building Sector Model, Report#:EIA/DOE-0607(99)
[illegible]

Table A3:. Summary of Price Responses in the NEMS *AEO2003* and *AEO99*
Residential and Commercial Buildings Models

Sector and Fuel	NEMS Model Year	Short-Run Own-Price Elasticity			Long-Run Own-Price and Cross-Price Elasticity		
		1-Year	2-Year	3-Year	Electricity	Natural Gas	Distillate Fuel
Residential							
Electricity	*AEO2003*	-0.20	-0.29	-0.34	-0.49	0.01	0.00
	AEO99	-0.23			-0.31	0.03	0.00
Natural Gas	*AEO2003*	-0.14	-0.24	-0.30	0.13	-0.41	0.02
	AEO99	-0.26			0.08	-0.43	0.02
Distillate Fuel	*AEO2003*	-0.15	-0.27	-0.34	0.01	0.05	-0.60
	AEO99	-0.28			0.06	0.16	-0.63
Commercial							
Electricity	*AEO2003*	-0.10	-0.17	-0.20	-0.45	0.01	0.00
	AEO99	-0.23			-0.24	0.00	0.00
Natural Gas	*AEO2003*	-0.14	-0.24	-0.29	0.86	-0.40	0.01
	AEO99	-0.26			0.00	-0.34	0.03
Distillate Fuel	*AEO2003*	-0.13	-0.23	-0.28	0.08	0.75	-0.39
	AEO99	-0.47			0.00	0.49	-0.87
Commercial Electricity by End Use							
Core End Uses	*AEO2003*	-0.17	-0.29	-0.36	-0.88	—	—
	AEO99	-0.24			-0.31	—	—
Other End Uses	*AEO2003*	-0.03	-0.05	-0.06	-0.24	—	—
	AEO99	-0.24			-0.20	..	.

Source: Steven H. Wade, Price Responsiveness in the AEO2003 NEMS Residential and Commercial Buildings Sector Models, Energy Information Agency, March 2005
http://www.eia.doe.gov/oiaf/analysispaper/elasticity/

Appendix B
Comments on the EMSI Input-Output Model

We completed the impact analysis reported above using the Economic Modeling Specialists, Inc. (EMSI) EI Model. The EMSI EI Model is constructed using the U.S. National IO Model using standard non-survey IO modeling techniques. For more information on the EMSI EI Model see: www.economicmodeling.com.

Short-Run

Following standard practice, we define the "short-run" as the period over which little adjustment to higher electricity prices are possible: there is no direct change in industry outputs, industry inputs or the relative proportion of total income spent on the various goods that make up the household consumption bundle. The $150 million in increased electricity costs are entirely born by business owners in the case of private industry, by reductions in employee wages in the case of government, and by a reduction in the real purchasing power of households. We display the short-run "direct impact" as the direct loss of business owner and government sector incomes. Indirect impacts are estimated by applying the effective loss of household income, i.e., the loss of owners' and government worker incomes, and the net real reduction in household spending, to the household sector of the IO model.

Long-Run

Generally speaking, IO models do not allow for changes in the relative use of production inputs: e.g., the adoption of conservation measures, or the substitution of natural gas or other energy sources for electricity. Within the context of fixed input proportion we are, however, able to model the effect of higher electricity prices on overall industry outputs, and speculate on the magnitude of neglected substitution effects.

For our long-run analysis, we assume businesses owners move to recapture lost profit margins by raising prices, and that government reduces overall service levels. We assume the elasticity of demand for final products are unitary, so the effect of shifting electricity price increases to final output prices is an exactly equal reduction in business output. We enter these reductions into the model as changes in final demand.

Minnesota Chamber of Commerce
Information Request No. 6 to Excelsior Energy

6. In the event the Commission orders provisions in the contract that require liquidated damages or actual damages for failure to perform under the PPA, please describe Excelsior's ability to pay for damages, i.e. Excelsior and/or Affiliate's retained earnings or cash or other means available to pay such damages.

Excelsior Energy
Response to Minnesota Chamber of Commerce IR No. 6

MEP-I LLC, as the owner of Mesaba Unit 1, will have assets in excess of $1.5 billion and will otherwise be appropriately capitalized to meet all obligations required by its lenders and under the PPA.

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy		
Docket No.:	E6472/M-05-1993	
Response To:	MN Chamber of Commerce	Information Request No. 19
Date Received:	October 17, 2006	

Question:

A. Has Xcel ever contracted with an independent power producer that was unable to provide security in the event that plant is not online as scheduled or unable to produce baseload power?

B. In other PPAs Xcel has entered into, is the independent power producer liable for actual or liquidated damages, and does the power producer ordinarily have sufficient net worth to pay for such damages?

Response:

A. Yes. In the early days of PURPA, one of the operating companies of Xcel Energy Inc. had one contract fail in part for failure by the seller to post required security. Posting the security is generally viewed as a prerequisite to Xcel Energy's willingness to go forward with the transaction. It should be noted that financial security has not been required for some of the smaller projects that Xcel Energy has been involved with. For example, in the less-than-two-megawatt wind PPA context, some contracts were negotiated without security. For larger PPAs, such as Calpine/Mankato and Invenergy/Cannon Falls, security has been required and has been posted.

B. Typically, our PPAs have liquidated damages for delays in Commercial Operation. In addition, power sellers are liable for actual damages for harm caused to Xcel Energy as a result of breaches of the agree. In some circumstances, those actual damages can include the obligation to reimburse Xcel Energy for the cost of replacement power resulting from the seller's failure to perform. Typically, PPAs are entered into with a "seller" who is a single-purpose entity designed to hold the investment. Because of this structure, in our larger transactions, Xcel Energy uses a basket of tools to increase the likely of being paid for damages due, including a security fund or parental guarantee, rights to offset amounts due Xcel Energy from amounts due from Xcel Energy to Seller, and subordinated liens.

Response By:	Karen Hyde
Title:	Managing Director, Resource Planning and Acquisition
Date:	October 30, 2006

AFFIDAVIT OF SERVICE BY E-MAIL AND U.S. MAIL

STATE OF MINNESOTA)
) ss.
COUNTY OF RAMSEY)

Callie Johnson, of the City of St. Paul, County of Ramsey, State of Minnesota, being duly sworn upon oath, says that on the 31st day of October, 2006, she served the attached Surrebuttal Testimony of William Blazar on the following person(s) at their last known address, by e-mail and by placing a true and correct copy of said document in an envelope addressed to said person at his/her last known address, and placing said envelope with said contents in the U.S. Mail at St. Paul, Minnesota:

See Service List.

Callie Johnson

Callie Johnson

Subscribed and sworn to before me
this 31st day of October, 2006.

DeAnn R Simonson

Notary Public

DEANN R. SIMONSON
Notary Public
Minnesota
My Commission Expires January 31, 2010

STPL-Word:90414.1

OAH Docket No. 12-2500-17260-2
E-6472/M-05-1993

In the Matter of a Petition by Excelsior Energy, Inc., . . .
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